North Killingholme Power Project

Non-Material Change to Development Consent Order

Carbon Capture Readiness Feasibility Study / Carbon Capture and Storage Design Concept Report

C.GEN Killingholme Limited

QUALITY CONTROL

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LIST OF ABBREVIATIONS

Ar	Argon
ASU	Air Separation Unit
BAT	Best Available Techniques
BEIS	Business, Energy and Industrial Strategy
CAPEX	Capital Expenditure
CCGT	combined cycle gas turbine
CCR	carbon capture readiness / carbon capture ready
CCS	carbon capture and storage
CEMP	Construction Environmental Management Plan
CO2	carbon dioxide
DCO	Development Consent Order
DECC	Department of Energy and Climate Change
DLN	Dry Low NO_x
EA	Environment Agency
EPC	Engineering, Procurement and Construction
EPS	Emissions Performance Standard
EU	European Union
FEED	Front End Engineering Design
FOAK	First of a Kind
H_2	hydrogen
H_2O	water
H_2S	hydrogen sulphide
ha	hectares
HCl	hydrochloric acid
HDD	Horizontal Directional Drilling
HHV	higher heating value
HP	high pressure
HRSG	Heat Recovery Steam Generator
HSC	Hazardous Substances Consent
HSE	Health and Safety Executive
HV	high voltage
IED	Industrial Emissions Directive
IGCC	integrated gasification combined cycle
IP	intermediate pressure
km	kilometres
LCPD	Large Combustion Plant Directive
LHV	lower heating value
LP	low pressure
LV	low voltage
m	metres
MV	medium voltage
MW	megawatt
N_2	nitrogen

NH_3	ammonia
NOAK	Next of a Kind
NPS	National Policy Statement
NSIP	Nationally Significant Infrastructure Project
OPEX	Operation and Maintenance Costs
PAH	Polyaromatic Hydrocarbons
SAC	Special Area of Conservation
SMA	Special Marine Area
SNS	South North Sea
SPA	Special Protection Area
SSSI	Site of Special Scientific Interest
TPH	Total Petroleum Hydrocarbons

EXECUTIVE SUMMARY

An application was made for a Development Consent Order in April 2013 ('the Application') to construct and operate a new 470 megawatt (MW) electrical generating station (generating station) and associated development on land at North Killingholme, North Lincolnshire ('the Project'). The North Killingholme (Generating Station) Order 2014 was granted by the Secretary of State on 11 September 2014 (amended by correction order on 26 October 2015) (together 'the Order').

Since being granted the Order, C.GEN has been developing the Project for delivery, including appointing a preferred contractor and participating in the Capacity Market auctions. Given the time that has elapsed since the Order was granted, C.GEN is seeking an extension to the Order to enable it to deliver the Project to reflect current market conditions as well as the operation of the Capacity Market.

This "Feasibility Study" document has been prepared as a revision to the Carbon Capture Readiness Feasibility Study / Carbon Capture and Storage Design Concept Report, 22 March 2013, Document Reference: 8.4 ("2013 Submission").

The 2013 Submission looked at a pre-combustion for carbon capture based on an IGCC Plant using 100% coal as fuel. Whilst the IGCC mode of operation does not currently look feasible to deliver as it is dependent on development of a carbon transport and storage network by third parties, the IGCC option remains a viable technological solution to low-carbon energy production needs. However, as the Order enables C.GEN to deliver and operate the Project in CCGT mode, C.GEN is now seeking an amendment to the provisions of the Order to secure the provision of post-combustion carbon capture, which includes allocating and protecting a sufficient area of land for that purpose. This amendment will mean that the carbon capture readiness of the Project will be secured by a post-combustion carbon capture solution, rather than the IGCC option. It will still be possible to bring forward the IGCC elements of the Project. If that happens, the post-combustion capture solution would not be required, and the Project would rely on pre-combustion carbon capture. The proposed amendment ensures that the Project reflects current requirements for carbon capture readiness.

This revised Feasibility Study incorporates carbon capture ready solutions for the two key operating scenarios (simplified to two key operating scenarios from the five scenarios outlined in the Environmental Statement Volume 1, 22 March 2013, Document Reference 6.1):

- Operation of Generating Station as a CCGT plant (using natural gas as fuel).
- Operation of Generating Station as an IGCC Plant (using 100% coal as fuel as it represents the worst-case scenario for CO2 capture).

In line with the requirements of the Overarching National Policy Statement for Energy ('NPS EN-1'), the Carbon Capture Readiness (CCR) – A Guidance Note for Section 36 Electricity Act 1989 Consent Applications ('CCR Guidance') and the Draft Supplementary Guidance for Section 36 Electricity Act 1989 Consent Applications for Coal Power Stations: A Consultation ('Draft Supplementary Guidance'), this revised CCR Feasibility Study / CCS Design Concept Report has been prepared to support the application for an extension to the Order.

With regards to the requirement for a CCR Statement / Feasibility Study, the European Union (EU) agreed the text of the Directive on the geological storage of carbon dioxide (Directive 2009/31/EC) ('the CCS Directive') on 17 December 2008. This text was published in the Official Journal of the EU on 5 June 2009 and the CCS Directive came into force on 25 June 2009.

The CCS Directive amended (inserting Article 9a) Directive 2001/80/EC on the limitation of emissions of certain pollutants into the air from large combustion plants (commonly known as the Large Combustion Plant Directive or LCPD). The LCPD has since been replaced by Directive 2010/75/EU on industrial emissions (integrated pollution prevention and control) (commonly known as the Industrial Emissions Directive or IED).

Consequently, Member States are required to ensure that operators of all combustion plants with an electrical power generating capacity of 300 MW or more (and for which the construction / operating licence was granted after the entry into force of the CCS Directive) have assessed whether the following conditions are met in respect of each combustion plant:

a) Suitable storage sites for CO2 are available;

b) Transport facilities are technically and economically feasible; and,

c) It is technically and economically feasible to retrofit the combustion plant for CO2 capture.

The assessment of whether these conditions are met is to be submitted to the relevant competent authority, who will use the assessment (and other available information) in their decision-making process in respect of consent for each combustion plant. If the conditions are met, the competent authority is to ensure that suitable space is set aside for the CO2 capture technology necessary to capture and compress CO2 from the combustion plant.

In the UK the relevant competent authority (in respect of applications for DCOs on energy matters) is the Department for Business, Energy and Industrial Strategy (BEIS) (formerly known as the DECC). BEIS must ensure the requirements of the relevant EU Directives are implemented and their transposition into domestic law/policy. BEIS is also able to impose more stringent regulations or requirements on combustion plants in the UK. In giving effect to this, the UK Government has published policy on CCR (CCR Policy) within sections at 4.7 of NPS EN-1.

Under the CCR Policy within NPS EN-1, and as part of an application for a DCO, applicants will be required to demonstrate:

- *"that sufficient space is available on or near the site to accommodate carbon capture equipment in the future;*
- *the technical feasibility of retrofitting their chosen carbon capture technology;*
- *that a suitable area of deep geological storage offshore exists for the storage of captured CO2 from the proposed power station;*
- *the technical feasibility of transporting the captured CO2 to the proposed storage area; and*
- *the likelihood that it will be economically feasible within the power station's lifetime, to link it to a full CCS chain, covering retrofitting of capture equipment, transport and storage".*

Furthermore, the CCR Guidance states that: "if applicants' proposals for operational CCS involve the use of hazardous substances, they may be required to apply for Hazardous Substances Consent (HSC). In such circumstances, they should do so at the same time as they apply for ... [a DCO]".

Under the Draft Supplementary Guidance, and as part of an application for a DCO (in respect of a new coal-fired electrical generating station), applicants will be required to submit:

- *"Technically feasible plans for a capture unit covering the minimum size requirement of at least 300 MWe net capacity of the power station … ;*
- *An Environmental Statement for the power station, including the impacts of the proposed capture facilities … ; and,*
- *Documentation to ensure compliance with all other existing policy including that the entire plant's capacity is CCR".*

It is considered that the information provided in this CCR Feasibility Study has successfully demonstrated compliance with the CCR Policy within NPS EN-1 and the requirements within the Draft Supplementary Guidance.

1 INTRODUCTION

1.1 Overview

An application was made for a Development Consent Order in April 2013 ('the Application') to construct and operate a new 470 megawatt (MW) electrical generating station (generating station) and associated development on land at North Killingholme, North Lincolnshire ('the Project'). The order was granted by the Secretary of State on 11 September 2014 (amended by correction order on 26 October 2015) (together 'the Order').

The Order authorises the operation of the Project in two modes: either as a CCGT plant or as an IGCC plant. The CCGT plant would be fired on natural gas, obtained from existing high-pressure gas supply pipes in the area that cross C.GEN's land. If operating as an IGCC plant, the Project would be fuelled by coal, possibly blended with petroleum coke or biomass.

Since being granted the Order, C.GEN, (as the promoter / developer) has been developing the Project for delivery, including appointing a preferred contractor and participating in the Capacity Market auctions. Given the time that has elapsed since the Order was granted, C.GEN is seeking an extension to the Order to enable it to deliver the Project to reflect current market conditions as well as the operation of the Capacity Market.

This "Feasibility Study" document has been prepared as a revision to the Carbon Capture Readiness Feasibility Study / Carbon Capture and Storage Design Concept Report, 22 March 2013, Document Reference: 8.4 ('the 2013 Submission').

The 2013 Submission looked at a pre-combustion for carbon capture based on an IGCC Plant using 100% coal as fuel. Whilst the IGCC mode of operation does not currently look feasible to deliver as it is dependent on development of a carbon transport and storage network by third parties, the IGCC option remains a viable technological solution to low-carbon energy production needs. However, as the Order enables C.GEN to deliver and operate the Project in CCGT mode, C.GEN is now seeking an amendment to the provisions of the Order to secure the provision of post-combustion carbon capture, which includes allocating and protecting a sufficient area of land for that purpose. This amendment will mean that the carbon capture readiness of the Project will be secured by a post-combustion carbon capture solution, rather than the IGCC option. It will still be possible to bring forward the IGCC elements of the Project. If that happens, the post-combustion capture solution would not be required, and the Project would rely on pre-combustion carbon capture. The proposed amendment ensures that the Project reflects current requirements for carbon capture readiness.

This revised Feasibility Study incorporates carbon capture ready solutions for the two key operating scenarios (simplified to two key operating scenarios from the five scenarios outlined in the Environmental Statement Volume 1, 22 March 2013, Document Reference 6.1):

- Operation of Generating Station as a CCGT plant (Using natural gas as fuel).
- Operation of Generating Station as an IGCC Plant (Using 100% coal as fuel as it represents the worst-case scenario for CO2 capture).

The revised Feasibility Study will demonstrate it is technically feasible to retrofit the plant to capture, transport and store CO2 for both of the two key operating scenarios in line with the Draft Supplementary Guidance[1] and CCR Guidance[2].

1.2 Application for a Development Consent Order

Under Section 31 of the Planning Act 2008, a DCO is required to authorise a Nationally Significant Infrastructure Project (NSIP). In England and Wales, an onshore electricity generating station is considered to be a NSIP if the electrical power generating capacity is more than 50 MW. As the electrical power generating capacity of the generating station will exceed this threshold, a DCO is required. A DCO may only be granted pursuant to an application under Section 37 of the Planning Act 2008.

To inform decisions upon applications under Section 37 of the Planning Act 2008 for NSIPs in England and Wales, the Planning Act 2008 required the development and implementation of new Policy. Accordingly, Policy for NSIPs is set out in National Policy Statements (NPS). Those that are relevant to this CCR Feasibility Study are:

The Overarching National Policy Statement for Energy (NPS EN-1); and,

The National Policy Statement for Fossil Fuel Electricity Generating Infrastructure (NPS EN-2).

1.3 Purpose and Structure of this Document

In line with the requirements of NPS EN-1, the CCR Guidance, CCS Directive[3] (with the relevant language since recast in the IED[4]) and the Draft Supplementary Guidance, this Feasibility Study will follow the same structure as the 2013 Submission but include the following additional detail (Shown in red):

Introductory Information:

Section 1 - This brief introduction. *(Minor updates as applicable)*

Section 2 – The context and assessment methodology. *(Updated to include government policy on post-combustion capture).*

Section 3 – A description of the North Killingholme Power Project. *(Minor updates as applicable)*

Carbon Capture Technology Information:

Section 4 – A description of the proposed CO2 capture technology *(Updated to include description, performance and calculations for both pre-combustion and post-combustion technology).*

Technical Assessments:

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[1] *November 2009 consultation document - Draft Supplementary Guidance for Section 36 Electricity Act 1989 Consent Applicants for Coal Power Stations*

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

[3] *Directive on the geological storage of carbon dioxide (Directive 2009/31/EC) (the Carbon Capture and Storage (CCS) Directive)*

[4] *Directive on industrial emissions (integrated pollution prevention and control) (Directive 2010/75/EU) (the Industrial Emissions Directive (IED))*

Section 5 – The technical assessment of the CO2 capture technology space. *(Updated to assess space requirements for both pre-combustion and post-combustion technology. Separate assessments and layouts are provided for each technology)*

Section 6 – The technical assessment of the retrofitting and integration of the CO2 capture technologies. *(Updated to include what retrofitting and integration is required for both pre-combustion and post-combustion technology)*

Section 7 – The technical assessment of CO2 storage areas. *(Updated to include details of new required CO2 storage capacity and review to ensure original storage location is still valid)*

Section 8 – The technical assessment of CO2 transport. *(Updated to ensure original CO2 Transport route is still valid)*

Economical Assessment:

Section 9 – The economical assessment. *(Updated to include economic assessment for both pre-combustion and post-combustion technology. Separate, independent assessments carried out).*

Additional Information:

Section 10 – A discussion on the requirement for a Hazardous Substances Consent. *(Updated to evaluate the potential requirement for a HSC for both pre-combustion and post-combustion technology)*

Conclusions:

Section 11 – Conclusions *(Updated as applicable)*

Figures:

The following additional Figures have been added:

- *Figure 9 – Schematic of Post Combustion Carbon Capture*
- *Figure 10 – Outline Plot Level Plan for CCGT Power Plant with Post-Combustion CO2 Capture*

Appendix A:

Relevant Sections of the EU Directives *(No update required)*

Appendix B

CCR / CCS Requirements Checklist – *(Table B3 added to include CCR Guidance Requirements for CCGT Plant with post-combustion capture)*

Appendix C

Annex B of Carbon Capture Readiness (CCR) Guidance (November 2009) – "Environment Agency Verification of CCS Readiness New Natural Gas Combined Cycle Power Station Using Pre-Combustion CO2 Capture (including coal gasification) and Hydrogen-Rich Fuel Gas Combustion" *(No update required).*

Appendix D

Annex C of the ‘Draft Supplementary Guidance’ (November 2009) – “Environment Agency Verification of CCS Technical Feasibility: New Integrated Gasification Combined Cycle Power Station using Pre-Combustion CO2 Capture (Coal Gasification) and Hydrogen-Rich Fuel Gas Combustion)” *(No update required).*

Appendix E

Annex C of Carbon Capture Readiness (CCR) Guidance (November 2009) – “Environment Agency verification of CCS Readiness New Natural Gas Combined Cycle Power Station Using Post-Combustion Solvent Scrubbing” *(New Appendix added).*

2 CONTEXT ASSESSMENT AND METHODOLOGY

The directive and policy requirements set out in the 2013 Submission have been reviewed and updated to include government policy on post-combustion capture.

2.1 EU Directive on Geological Storage of Carbon Dioxide

The European Union (EU) agreed the text of the Directive on the geological storage of carbon dioxide (Directive 2009/31/EC) (the CCS Directive) on 17 December 2008. This text was published in the Official Journal of the EU on 5 June 2009 and the CCS Directive came into force on 25 June 2009.

The CCS Directive amended (inserting Article 9a) Directive 2001/80/EC on the limitation of emissions of certain pollutants into the air from large combustion plants (commonly known as the Large Combustion Plant Directive or LCPD). Consequently, Member States are required to ensure that operators of all combustion plants with an electrical power generating capacity of 300 MW or more (and for which the construction / operating licence was granted after the entry into force of the CCS Directive) have assessed whether the following conditions are met in respect of each combustion plant:

a) Suitable storage sites for CO2 are available;

b) Transport facilities are technically and economically feasible; and,

c) It is technically and economically feasible to retrofit the combustion plant for CO2 capture.

The assessment of whether these conditions are met is to be submitted to the relevant competent authority, who will use the assessment (and other available information) in their decision-making process in respect of consent for each combustion plant. If the conditions are met, the competent authority is to ensure that suitable space is set aside for the CO2 capture technology necessary to capture and compress CO2 from the combustion plant.

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

The requirement for such an assessment is also included in the more recent Directive on industrial emissions (integrated pollution prevention and control) (Directive 2010/75/EU) (the Industrial Emissions Directive or IED). The LCPD has effectively now been replaced by the IED. The relevant sections of the IED are also attached in Appendix A.

Although no longer a Member State, the requirements set out in the CCS Directive have been transposed into UK law/policy (as outlined in the following sections) and so the requirements outlined in UK guidance shall be adhered to.

2.2 UK Government

In the UK, the relevant competent authority (in respect of applications for DCOs on energy matters) is the Department for Business, Energy and Industrial Strategy (BEIS) (formerly the Department of Energy and Climate Change (DECC). BEIS must ensure the requirements of the relevant EU Directives are implemented and transposed into domestic law/policy. BEIS is also able to impose more stringent regulations or requirements on combustion plants in the UK.

To help transpose the CCR requirements as outlined in the IED into UK law, the Carbon Capture Readiness (Electricity Generating Stations) Regulations 2013 ('CCR Guidance')[5] was enacted. Further guidance on the requirements is provided in Section 0.0.

As a supporting document to the CCR Guidance, the 'Draft Supplementary Guidance'[6] was produced. The document was draft guidance produced specifically for carbon capture and storage on new coal power stations and was released in November 2009 as part of a consultation document. It is understood that the document was never further developed from the draft consultation document although as reference was made to the consultation document in the 2013 Submission (Refer to Section 0.0), it has been kept in for this revision for completeness.

In accordance with the Planning Act 2008 (PA 2008)[7], the Secretary of State (SoS) is required to determine an application for a DCO for an energy NSIP in accordance with the Overarching National Policy Statement for Energy (EN-1) (2011, DECC)[8]. Further guidance on the requirements is provided in Section 0.0.

CCR Guidance Requirements - General

Under the CCR Guidance, and as part of an application for a DCO, the guidance states (at paragraph 7) that applicants will be required to demonstrate:

a) "*That sufficient space is available on or near the site to accommodate carbon capture equipment in the future;*

b) The technical feasibility of retrofitting their chosen carbon capture technology;

c) That a suitable area of deep geological storage off shore exits for the storage of captured CO2 from the proposed power station;

d) The technical feasibility of transporting the captured CO2 to the proposed storage area; and

e) The likelihood that it will be economically feasible within the power station's lifetime, to link it to the full CCS chain, covering retrofitting of carbon capture equipment, transport and storage".

Furthermore, the CCR Guidance states that: "*if Applicants' proposals for operational CCS involve the use of hazardous substances, they may be required to apply for Hazardous Substances Consent (HSC). In such circumstances, they should do so at the same time as they apply for ...* [a DCO]".

If granted consent, the CCR Guidance states (at paragraph 8) that applicants / operators will be required to:

a) "*Retain control over sufficient additional space on or near the site on which to install the … carbon capture equipment, and the ability to … use it for that purpose; and,*

b) Submit reports to the Secretary of State for DECC as to whether it remains technically feasible to retrofit CCS to the power station".

The CCR Regulation transposes the IED into UK law.

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[5] Carbon Capture Readiness (Electricity Generating Stations) Regulations 2013.
[6] Draft Supplementary Guidance for Section 36 Electricity Act 1989 Consent Applicants for Coal Power Stations, November 2009
[7] Planning Act 2008
[8] 'Overarching National Policy Statement for Energy (EN-1)' (2011, DECC).

Regulation 3 provides that the SoS must not make a development consent order unless the SoS has determined whether the CCR conditions are met in relation to the combustion plant to which the consent order relates.

Regulation 2 provides that the CCR conditions are met in relation to a combustion plant, if, in respect of all of its expected emissions of CO2—

a) *Suitable storage sites are available;*

b) *It is technically and economically feasible to retrofit the plant with the equipment necessary to capture that* CO2*; and*

c) *It is technically and economically feasible to transport such captured* CO2 *to the storage sites referred to in sub-paragraph (a).*

In accordance with regulation 3(2) the SoS's determination as to whether such conditions are met must be on the basis of:

a) *A CCR assessment of the combustion plant prepared by the person who made the application for the relevant consent order; and*

b) *Any other available information, particularly concerning the protection of the environment and human health.*

Regulation 3(3) continues:

"If the Secretary of State -

(a) Determines that the CCR conditions are met in relation to a combustion plant; and

(b) Decides to make a relevant consent order in respect of that plant,

the Secretary of State must include a requirement in the relevant consent order that suitable space is set aside for the equipment necessary to capture and compress all of the CO2 *that would otherwise be emitted from the plant."*

This assessment provides the necessary information to inform the SoS determination.

The Draft Supplementary Guidance - Coal-Fired Electrical Generation

The UK Government is taking a number of steps to facilitate and encourage the demonstration of CO2 capture technology, CO2 transportation and CO2 storage. NPS EN-1 states (at paragraph 4.7.4) that these steps are focussed initially on coal-fired electrical generating stations because:

- "*The emissions from coal generation are substantially higher than from other fuels, including gas"*;
- *"The projected increase in coal use globally creates a greater urgency to tackling emissions from coal"*;
- *"Tackling emissions from coal first makes most economic sense because of the greater emissions intensity"*; and,
- *"New coal generating stations would contribute to the diversity and security of UK energy supplies as we make the transition to a low carbon mix*".

Therefore, in addition to the CCR Policy, there is CCS policy for new coal power stations such that (as stated in NPS EN-1 at paragraph 4.7.5) "*new coal-fired generating stations, or* *significant extensions to existing stations, in England and Wales must have Carbon Capture and Storage on at least 300 MW net of the proposed generating capacity and secure arrangements for the transport and permanent storage of carbon dioxide*".

Therefore, all new coal-fired power plant must have CCS in place (on at least 300 MW net of the proposed generating capacity) to operate. Accordingly, the trigger imposed by the CCS Policy for provision of CCS is the operation of the power plant as a coal-fired power plant.

In terms of the requirement for CCS operation of the power plant as a coal-fired power plant, the Draft Supplementary Guidance document was produced. The document was produced specifically for carbon capture and storage on new coal power stations as part of a consolation document in November 2009. It is understood that the document was never further developed from the draft consultation document.

The purpose of the Draft Supplementary Guidance consultation document is outlined below:

"This consultation seeks views on the clarity and coverage of draft guidance on complying with the Government's new policy to require carbon capture and storage on new coal power stations, or on existing power stations where consent is sought for the installation of super-critical coal-fired boilers in England and Wales."

"The guidance is designed for applicants seeking consent under Section 36 of the Electricity Act 1989 (and in due course under the Planning Act 2008), to construct and operate a coal-fired power generating station in England and Wales."

"The guidance document will be publicly available. It will supplement the existing guidance on Carbon Capture Readiness (CCR) for Section 36 Electricity Act (1989) Consent Applicants."

The draft guidance document was produced for specific reference for carbon capture and storage on new coal power stations. It is understood that the document was never further developed from the draft consultation document. Although, as reference was made to the consultation document in the 2013 Submission, it has been kept in for this revision for completeness

The Draft Supplementary Guidance notes (at Section 3.1, paragraph 11) that where consent is given for the electricity generating station it will be conditional on the developer submitting to the Secretary of State for Energy and Climate Change, prior to commencement of construction, clear evidence of:

a) A valid CO2 Storage Permit / valid contract with third party to provide CO2 storage;

b) Valid CO2 transportation arrangements / valid contract with third party to provide CO2 transportation; and,

c) Valid Environmental Permit which incorporates conditions for the operation of the carbon capture unit / CCS Chain.

However, fulfilling these requirements would be the subject of separate consent applications to be made in due course.

As part of an application for a DCO (in respect of a new coal-fired electrical generating station), the Draft Supplementary Guidance states (at Section 3.1) that applicants will be required to submit:

- *"Technically feasible plans for a capture unit covering the minimum size requirement of at least 300 MWe net capacity of the power station … ;*
- *An Environmental Statement for the power station, including the impacts of the proposed capture facilities … ; and,*
- *Documentation to ensure compliance with all other existing policy including that the entire plant's capacity is CCR".*

Therefore, in relation to the CO2 capture, transport and storage facilities associated with a new coal-fired power plant, it is technically feasible to seek powers for construction of gasification and CO2 capture facilities at the same time as the power plant itself. This is because it is possible to undertake an environmental impact assessment of the gasification and CO2 capture facilities at the same time as the power plant, and therefore it is also possible to promote and obtain consent for the gasification and CO2 capture facilities together with the power plant. However, CO2 transport and storage facilities are also needed and to make the process complete, and these would need to be the subject of a separate consenting process. In the same way that NPS EN-1 recognises electrical grid connections and gas connections can be promoted separately from a power plant[9] a similar approach can be taken for CO2 transport and storage facilities required. Accordingly, where this approach is taken it is appropriate to comply with the Government's policy by restricting use of coal-fired elements unless CO2 transport and storage facilities are available for use.

Therefore, overall the Draft Supplementary Guidance can be maintained where gasification and CO2 capture facilities are promoted as part of a power plant. Specifically for this Application, the use of the coal-fired facility of the plant (with consented gasification and / or CO2 capture facility) can be restricted unless CO2 transport and storage facilities are complete and available for use.

Overarching National Policy Statement for Energy (NPS EN-1) Requirements

The requirement for the consideration and/or implementation of CCS CCR, is detailed within section 4.7 of NPS EN-1.

Paragraph 4.7.10 of EN-1 states:

"To ensure that no foreseeable barriers exist to retrofitting carbon capture and storage (CCS) equipment on combustion generating stations, all applications for new combustion plants which are of generating capacity at or over 300 MW and of a type covered by the EU's Large Combustion Plant Directive (LCPD) should demonstrate that the plant is "Carbon Capture Ready" (CCR) before consent may be given."

To assure that the Proposed Scheme is CCR, EN-1 states that the proposal shall comply with the CCR Guidance requirements (outlined above).

In this regard, NPS EN-1 states (also at paragraph 4.7.10) that:

"In order to assure the [Secretary of State] *that a proposed development is CCR, applicants will need to demonstrate that their proposal complies with guidance issued ... in November 2009 or any successor to it".*

The guidance (referenced in the above paragraph) is referred to as the CCR Guidance.

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[9] See NPS EN-1, paragraph 4.9.2.

Furthermore, NPS EN-1 states (at paragraph 4.7.5) that:

"*In addition to satisfying the CCR criteria, to reduce CO2 emissions new coal-fired generating stations, or significant extensions to existing stations, in England and Wales must have CCS on at least 300 MW net of the proposed generating capacity and secure arrangements for the transport and permanent storage of carbon dioxide. Coal-fired generating stations of less than 300 MW net capacity should show that their proposed generating station will be able to capture CO2 from their full capacity. Operators of fossil fuel generating stations will also be required to comply with any Emissions Performance Standard (EPS) that might be applicable, but this is not part of the consent's process".*

In this regard, NPS EN-1 states (at paragraph 4.7.9) that:

"*Further information on the CCS obligations to be imposed on new coal-fired power stations will be available in guidance issued by DECC. The* [Secretary of State] *must follow this CCS Guidance, or any successor to it, when considering applications for combustion generating stations".*

The CCS Guidance reference in the above paragraph is the Draft Supplementary Guidance as discussed previously in this section.

2.3 Verification of CCR / CCS

This Document provides the information required by the CCR Guidance and the Draft Supplementary Guidance. A checklist of this information (with reference to the relevant requirements of the CCR Guidance and Draft Supplementary Guidance [Specifically for Coal-Fired Electrical Generation]) is provided in Appendix B. Appendix B also contains references to where the additional information as required by the CCR Guidance and the Draft Supplementary Guidance can be found within this Document.

Both the CCR Guidance and Draft Supplementary Guidance states that DECC [BEIS] will be advised by the Environment Agency (EA) whether the submitted information meets the CCR / CCS Requirements. The EA will provide its advice on the technical feasibility of a proposal based on the CCR Guidance:

- Annex B (Environment Agency Verification of CCS Readiness New Natural Gas Combined Cycle Power Station Using Pre-Combustion CO2 Capture (including Coal Gasification) and Hydrogen-Rich Fuel gas Combustion) (Included in Appendix C); and
- Annex C (Environment Agency verification of CCS Readiness New Natural Gas Combined Cycle Power Station Using Post-Combustion Solvent Scrubbing) of the CCR Guidance. (Included in Appendix E).

Annex C of the Draft Supplementary Guidance (Environment Agency Verification of CCS Technical Feasibility: New Integrated Gasification Combined Cycle Power Station using Pre-Combustion CO2 Capture (Coal Gasification) and Hydrogen-Rich Fuel Gas Combustion) (Included in Appendix D) was previously used by the EA to provide its advice of the technical feasibility. The extract was included in the 2013 Submission and so has been kept in for reference.

2.4 2013 Submission Compliance

The 2013 Submission demonstrated carbon capture readiness for an IGCC Power Plant with Pre-Combustion Capture through the requirements outlined in EN-1 and EN-2 and through the checklists provided in the CCR Guidance and Draft Supplementary Guidance, in which evidence of compliance was presented in Table B1 and Table B2 within Appendix B of the 2013 Submission.

Through the "Examining Authority's Report of Findings and Conclusions" (File Ref EN010038), the ExA have assessed the 2013 Submission report and have concluded that they believe that:

"CCS/CCR issues have been assessed adequately, and Requirements 34, 35 and 36 in the draft DCO [APP-114] for:

- *managing space arrangements;*
- *monitoring update reports and*
- *ensuring capture equipment is installed on site.*

Are robust and sufficient. The ExA believes that the requirements of NPS EN-1 and EN-2 have been adequately addressed."

As indicated in Section 2.3, this revised Feasibility Study retains the demonstration of carbon capture readiness for an IGCC Power Plant with Pre-Combustion Capture but also demonstrates compliance to EN-1 and the CCR Guidance for with a CCGT Power Plant with Post-Combustion Capture.

3 NORTH KILLINGHOLME POWER PROJECT

3.1 The Promoter / Developer

C.GEN, the promoter / developer of the Project, is a UK-based company that is part of the C.GEN Group of businesses (C.GEN Group), whose headquarters are in Luxembourg.

Established in early 2007, the C.GEN Group has been developing the concept of CCGT or coal-based electricity production with CO2 capture capabilities. In this regard, in 2007, the C.GEN Group started work with an engineering company, Foster Wheeler Italiana, to perform feasibility studies to allow the C.GEN Group to select the most appropriate technologies for this concept.

The C.GEN Group is affiliated to C.RO Ports Group, owners of the C.RO Ports Killingholme Limited Terminal (formerly Humber Sea Terminal). However, the businesses are separate and distinct, and the Project is being promoted by the C.GEN Group.

3.2 The Project

Since being granted the Order, C.GEN has been developing the Project for delivery, including appointing a preferred EPC contractor and participating in the Capacity Market auctions. Given the time that has elapsed since the Order was granted, C.GEN is seeking an extension to the Order to enable it to deliver the Project to reflect current market conditions as well as the operation of the Capacity Market.

The generating station is intended to operate either as a CCGT power plant or as an IGCC power plant. The generating station will be designed to provide a total electrical power generation capacity of up to 470 MW under normal operating conditions.

When operating as a CCGT power plant, the generating station will be fired on natural gas which will be obtained from existing high-pressure gas supply networks in the area.

When operating as an IGCC power plant, a variety of fuel mixtures may be used to allow the gas turbine to be fired on syngas. The variety of fuel mixtures include coal, either as a sole fuel or co-fired with petcoke or biomass (including as a sole fuel), which are subjected to pre-combustion treatment producing the syngas.

Accordingly, the generating station may be operated (and has been assessed for operation) in a number of modes. These modes include:

a) In CCGT power plant mode, fuelled by natural gas from the existing high-pressure National Gas Transmission System; and,

b) In IGCC power plant mode, fuelled by syngas produced by:

    i. The gasification of coal (or other fossil fuel / mixture of fossil fuels with biomass) with CO2 capture;

    ii. The gasification of coal (or other fossil fuel / mixture of fossil fuels with biomass) but without CO2 capture which may only take place in the circumstances outlined in Requirement 38(b)(ii) within the Order; or,

    iii. The gasification of torrefied biomass as a sole fuel without CO2 capture (as this is not required UK Policy).

For each of the above modes, the Environmental Statement (ES), which accompanied the application for a DCO, looked at worst case scenarios that include the above. This is based on the premise that:

a) CCGT power plant mode has been assessed in any event (and is included in the ES);

b) For operation in IGCC power plant mode, it is considered that gasification of coal (or other fossil fuel / mixture of fossil fuels with biomass) with CO2 capture represents the worst-case scenario (and is assessed and included in the ES);

c) Operation with the gasification of coal (or other fossil fuel / mixture of fossil fuels) with CO2 capture consumes the greatest amount of fuel. Therefore, (except for CO2 emissions) all parameters assessed on a coal / other fossil fuel / mixture of fossil fuels basis or biomass-only basis are worst case (e.g. air quality, noise, transport); and

d) Operation as an IGCC power plant without CO2 capture will not be a worst-case scenario, except in relation to CO2 emissions.

The 2013 Submission looked at a pre-combustion for carbon capture based on an IGCC Plant using 100% coal as fuel. Whilst the IGCC mode of operation does not currently look feasible to deliver as it is dependent on development of a carbon transport and storage network by third parties, the IGCC option remains a viable technological solution to low-carbon energy production needs. However, as the Order enables C.GEN to deliver and operate the Project in CCGT mode. C.GEN is now seeking an amendment to the provisions of the Order to secure the provision of post-combustion carbon capture, which includes allocating and protecting a sufficient area of land for that purpose. This amendment will mean that the carbon capture readiness of the Project will be secured by a post-combustion carbon capture solution, rather than the IGCC option. It will still be possible to bring forward the IGCC elements of the Project. If that happens, the post-combustion capture solution would not be required, and the Project would rely on pre-combustion carbon capture. The proposed amendment ensures that the Project reflects current requirements for carbon capture readiness. C.GEN notes that this approach has been permitted for other similar projects.

This revised Feasibility Study retains the IGCC Plant operating scenario but also incorporates the CCGT plant operating scenario. Specifically, the revised Feasibility Study looks at the physical and technical solutions comprising:

1. An IGCC power plant with CO2 capture (i.e. a pre-combustion gasifier with CO2 capture via a shift reactor when CO2 capture is taking place);

2. A CCGT power plant with post-combustion CO2 capture (i.e. the capture of CO2 from the flue gas leaving the exhaust through the use of amine based solvents).

Where other IGCC power plant operating scenarios apply (such as operation with no CO2 capture, or biomass-only production of syngas), the shift reactor would be bypassed, enhancing power plant efficiency, altering the composition of the syngas burned in the generating station gas turbines and allowing CO2 to be emitted. These IGCC power plant operating scenarios would only be allowed in controlled circumstances and / or in accordance with the DCO.

Comparative data for the different operating scenarios are set out in this Document to allow comparison with the CCGT power plant with post-combustion CO2 capture and IGCC power plant with pre-combustion CO2 capture.

3.3 The Project Site Location and Ownership

The Project comprises three main elements which make up the Application Site. These three main elements are:

a) The Principal Project Area;

b) The Electrical Grid Connection Land; and,

c) The Gas Connection Land.

The entire Application Site is located within the administrative boundary of North Lincolnshire Council. The Principal Project Area is wholly located within the parishes of North Killingholme and East Halton.

This CCR Feasibility Study considers plant / equipment within the Principal Project Area. The Principal Project Area is shown on Figure 1 and includes:

a) The Operations Area (The Operations Area is also shown on Figure 1) –

This is the area proposed for the generating station.

For the IGCC scenario, the generating station is made up of two principal elements: the power island and the gasification plant. The power island comprises all the equipment required for the generating station to operate as a CCGT power plant. The gasification plant comprises the further equipment required for the generating station to operate as an IGCC power plant (i.e. it comprises the equipment required for the gasification of solid fuels and accommodates facilities for CO2 capture).

In addition, this area will include common facilities required for operation as either a CCGT power plant or an IGCC power plant, such as: the cooling towers; offices and workshop; raw water treatment; wastewater treatment; and gas insulated switchgear.

a) For the CCGT plant retrofitted with post-combustion carbon capture, the generating station is again made up of two principal elements: the power island and the post-combustion CO2 capture plant. The power island comprises all the equipment required for the generating station to operate as a CCGT power plant. The post-combustion CO2 capture plant comprises the further equipment required to capture, processing and compression of CO2 from the flue gas from the CCGT power plant. Fuel Handling Areas –

These areas are the locations for the facilities needed for IGCC to supply solid fuel to the gasifier serving generating station via rail or sea and conveyors.

a) Cooling Water Connection Area –

This area will comprise an intake and outfall from the River Humber, at a location likely to be on or around the existing C.RO Ports Killingholme Limited Terminal jetties.

b) Construction Lay-Down Areas –

These areas are indicative locations for construction lay-down.

C.GEN controls (or is able to access and develop) the land comprising the Principal Project Area. Further information is provided in Section 5 (Technical Assessment – Space). The Principal Project Area (centred upon the Operations Area) is approximately 5 km north-west of Immingham Docks, on land adjacent to the C.RO Ports Killingholme Limited Terminal. This is in the Yorkshire and the Humber region of England.

The nearest residential settlements to the Operations Area are:

a) East Halton (approximately 1.2 km to the west);

b) North Killingholme (approximately 2 km to the south west); and

c) South Killingholme (approximately 3 km to the south west).

The Operations Area lies approximately 6 km north of the A180(T) dual carriageway. To the south of the Operations Area, the A160(T) runs east to west to provide a link with the A180, which in turn links with the M180 motorway (at Junction 5) and, thereby, with the wider motorway network. To the south of the Operations Area are the decommissioned (now demolished) Centrica Killingholme A Power Station and the non-operational (soon to be decommissioned) Killingholme B Power Station. .

3.4 The Current Conditions at the Application Site

Geotechnical Conditions

In terms of geotechnical conditions, BGS 1:50,000 Series, Sheet 81 (Partington) Solid and Drift Edition indicates that the Operations Area is underlain by alluvium, which overlies a thick layer of glacial till, which in turn overlies deposits of Burnham Chalk at significant depth. Geology maps also indicate that a relatively large area (circa 1 ha) in the south west of the Operations Area is underlain by made ground.

Previous ground investigations undertaken at the site largely confirmed this geological sequence. However, the Burnham Chalk deposits have not been proven by intrusive investigation.

As such, the importance of soils underlying the Operations Area has been classed as low as the Operations Area is predominantly brownfield land which has been used in the past by potentially polluting industry.

Further information, concerning the baseline and impact assessment, is provided in Section 14 of the ES (Geology and Land Contamination).

Site Contamination

In terms of site contamination:

a) The Operations Area is the site of a former Naptha Production Facility associated with the gas industry. As a result, there are a number of pollutants on site within the Operations Area. Indeed, previous reports undertaken of the Operations Area have identified elevated levels of contamination, including Polyaromatic Hydrocarbons (PAH) and Total Petroleum Hydrocarbons (TPH). Further information is provided in Section 14 of the ES (Geology and Land Contamination).

b) There are several potential off-site sources of contamination. Of the surrounding industries (both historical and current), the most likely off-site sources of contamination are from old landfill sites and the former Killingholme A Power Station site and the Killingholme B Power Station.

c) There are several landfill sites recorded within 1 km of the Operations Area. Of these landfill sites, the closest is at the C.RO Ports Killingholme Limited Terminal (formerly the Humber Sea Terminal), 16 m north of the proposed Operations Area. However, this landfill site is not currently active and is now covered in asphalt. In addition, when it was in operation it only accepted inert waste (as confirmed by the Environment Agency). Therefore, is it considered that there is a low potential for leachate / ground gas to migrate and contaminate the soils / groundwater at the Operations Area.

d) There are several pollution incidents which have occurred within 1 km of the Operations Area. However, none of these pollution incidents has a significant impact on land and there has been a significant time since the last incident occurred.

Therefore, it is considered that these are unlikely to have significantly impacted the quality of land at the Operations Area.

Further information, concerning the baseline and impact assessment, is provided in Section 14 of the ES (Geology and Land Contamination).

3.5 Site Access

The proposed access to the Operations Area is via either the A180 then the A160 or the A180 then the A1173.

The A180 is a rural 70 mph 2-lane dual carriageway with hard-strips rather than hard shoulders. It runs from east to west, to the south of the Application Site.

The A160 is split into a number of sections, and as such:

a) At departing from the A180, the A160 is known as Ulceby Road and is a 60 mph single carriageway rural road.

b) After the roundabout junction, the A160 is known as Humber Road and is a 70 mph 2-lane dual carriageway with hard-strips rather than hard shoulders. East of the junction with Eastfield Road, the Humber Road is within an industrial environment with minor access to the industrial areas.

The A1173 is also split into a number of sections, and as such:

a) At departing from the A180, the A1173 is a rural 60 mph single carriageway road.

b) After the first roundabout junction, the A1173 is known as Kings Road and is an urban industrial 40 mph single carriageway road.

c) After the second roundabout junction, the A1173 is known as Manby Road and is a 70 mph dual carriageway road.

Further information is provided in Section 12 of the ES (Traffic and Transport).

3.6 Propose Site Preparation and Building Design

Proposed Site Preparation

For both the construction of a CCGT power plant or an IGCC power plant, the proposed site preparation works are likely to be very similar. As such, in both cases the site preparation works will comprise the raising of the site (as necessary), earthworks, and the excavations for foundations.

Prior to site preparation works, further investigations / studies[10] to verify the assessed geotechnical conditions and site contamination will be undertaken. Based on the results of these further investigations / studies, a program of remediation works would be undertaken across the Principal Project Area as necessary. Remediation Validation Reports would be produced to document the remediation works undertaken.

[10] *To those undertaken as part of the Environmental Impact Assessment*

Building Layout and Design

In terms of building layout and design, the approach adopted is to apply a rationale to the layout of the Operations Area having regard to the surrounding landscape (both the immediate and wider landscape). Accordingly, the building layout and design will largely be related to limiting any landscape and visual impacts as well as other effects such as the effect of noise emissions upon nearby residential receptors.

With regard to limiting and landscape and visual impacts, the following will influence the final design:

a) The constraints imposed by the proposed building uses, including other structures and the need for boundary fencing);

b) The selection of colours to integrate new structures and boundary fencing into the receiving landscape and to blend with the colour of adjacent and nearby existing buildings;

c) The use of structured planting on the perimeter of the Application Site (where space permits and is compatible with ecological mitigation objectives); and,

d) The design of external lighting to reduce trespass, glare and spillage.

Further information is provided in Section 9 of the ES (Landscape and Visual Impact), and the Design and Access Statement.

3.7 Key Consents and Licences Required

The development and implementation of the Project will require a number of different Consents / Licences. A summary of the likely key Consents and Licences required for the Project is provided in Table 3.1. This summary will be regularly reviewed to reflect emerging information and accommodate changes in the regulatory regime relating to the Project and the gasification plant in particular.

3.8 Preliminary Programme

A preliminary programme for the development and implementation of the Project is provided in Insert 3.1. This preliminary programme will be regularly reviewed to reflect the options implemented for the Project.

The preliminary programme indicates the anticipated dates of Front End Engineering Design (FEED), Engineering Procurement Construction (EPC), commissioning and commercial operation.

The preliminary programme does not include the development, construction, commissioning and implementation of the facilities required for CO2 transportation or CO2 storage.

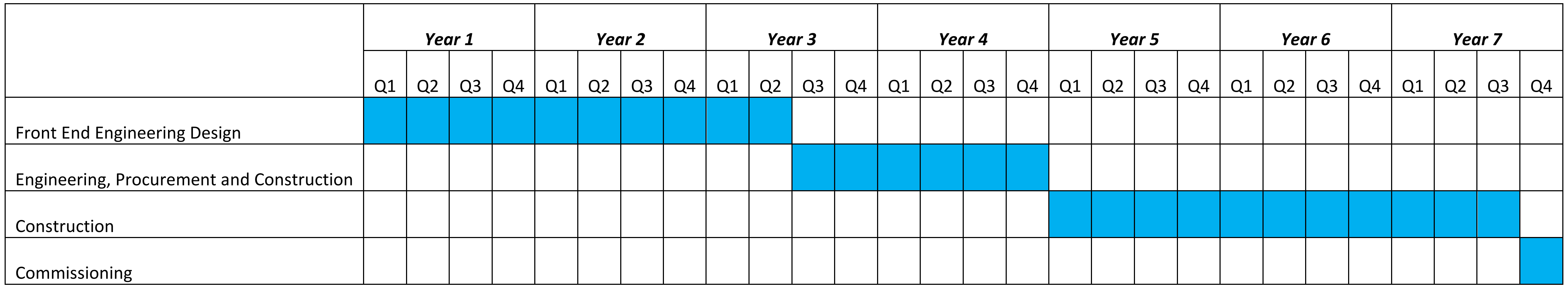
The preliminary programme provided in Insert 3.1 is for conversion to an IGCC pre-combustion solution; however, the high level programme for conversion to a post-combustion CCGT would be comparable (albeit most likely shorter in duration).

Table 3.1 - Key Consent and Licences Required

Area of the Project covered by the Consent / Licence	*Consent / Licence Title*	*Relevant Legislation*	*Granting Authority*	*Current Status*
Project	Development Consent Order	Planning Act 2008	Secretary of State for Energy and Climate Change	An application was made for a Development Consent Order in April 2013 ('the Application'), and an order was granted by the Secretary of State on 11 September 2014 (amended by correction order on 26 October 2015) (together 'the Order').
	Environmental Permit	Environmental Permitting (England and Wales) Regulations 2016	Environment Agency	Granted 2017
	Planning Hazardous Substances Consent	The Planning (Hazardous Substances) Regulations 2015	North Lincolnshire Council	To be determined whether applicable. Application process yet to commence.
	Control of Major Accident Hazard Licence	The Control of Major Accident Hazard Regulations 2015 (as amended)	Health and Safety Executive	To be determined whether applicable. Application process yet to commence.
	Greenhouse Gas Permit	The Greenhouse Gas Emissions Trading Scheme Regulations 2012 (as amended)	Environment Agency	Application process yet to commence.
	Water Abstraction Licence for the cooling water intake		Environment Agency	Application process yet to commence.
	Trade Effluent Licence for any discharges to sewer		Sewerage Undertaker	Application process yet to commence.
Associated Project Development	Planning Permission for the natural gas pipeline (from point of exit from the National Grid Gas National Transmission System to the site) and electrical grid connection	Town and Country Planning Act 1990	North Lincolnshire Council	The gas connection will be obtained with planning permission separate to this application. The grid connection will be delivered under permitted development rights.
	Advanced reservation of capacity agreement for the natural gas supply		National Grid Gas	There is a gas transportation agreement in place with Uniper Gas Transportation Services
	Bilateral Connection Agreement (for entry into the National Grid National Transmission System for the export of electricity from the site)		National Grid Electricity Transmission	Transmission Entry Capacity ('TEC') at the adjacent National Grid North Killingholme substation in place
CO2 Transport Pipeline (On shore)	Development Consent Order / Planning Permission for the on shore section of CO2 transport pipeline	Planning Act 2008 / Town and Country Planning Act 1990	Planning Inspectorate and Secretary of State / North Lincolnshire Council	Application process yet to commence.
	Health and Safety Notification and Approval for the on shore section of CO2 transport pipeline	Pipeline Safety Regulations 1996	Health and Safety Executive	Application process yet to commence.
CO2 Transport Pipeline Coastal Transition Point	Onshore to Offshore Connection Consent	Petroleum Act 1998	Department of Energy and Climate Change	Application process yet to commence.

Area of the Project covered by the Consent / Licence	*Consent / Licence Title*	*Relevant Legislation*	*Granting Authority*	*Current Status*
CO2 Transport Pipeline (Off shore)	Offshore Works Construction Authorisation	Coastal Protection Act 1949		Application process yet to commence.
	Pipeline Works Authorisation for the off shore section of CO2 transport pipeline	Petroleum Act 1998	Department of Energy and Climate Change	Application process yet to commence.
	Offshore Chemicals Permit for the off shore section of CO2 transport pipeline	Off shore Chemicals Regulations 2002	Department of Energy and Climate Change	Application process yet to commence.
CO2 Storage	CO2 Storage Lease		Crown Estates	Application process yet to commence.
	CO2 Storage Licence / Permit	Energy Act 2013	Department of Energy and Climate Change	Application process yet to commence.

Insert 3-1- Preliminary Programme [11]



[11] Year 1 is the first year after the decision is made to convert from a CCGT power plant to an IGCC power plant or to include post combustion CO2 capture on the CCGT plant.

4 PROPOSED CO2 CAPTURE TECHNOLOGY

Alongside the information from the 2013 Submission, a CCGT Power Plant with Post-Combustion CO2 Capture has been modelled in Thermoflow GT Pro software. The model calculates the amount of CO2 emitted, compares the auxiliary power requirements of each set-up and uses the heat rate LHV (kJ/kWH) in the cost modeller to provide a comparative economical assessment. A block flow diagram and heat and material balance (HMB) have also been produced and included within the section for comparative purposes.

4.1 Selection of Proposed CO2 Capture Technology

The proposed CO2 capture technologies used are pre-combustion CO2 capture technology using CO2 shift reaction gasification and post-combustion CO2 capture technology using amine based solvents.

However, as noted in the CCR Guidance (paragraph 26) *"the Government does not intend to insist that an applicant, when in time they come .... to install CCS must do so on the basis of the [CCS] technology declared at the CCR stage. [Indeed,] the Government recognises that CCS technology is still developing and does not wish to bind operators to a technology which may be less effective or less economic that that available to applicants at the stage of CCS retrofit"*.

Furthermore, as noted in the CCR Guidance (paragraph 27) *"the Government intends to consider applicants' CCR [Feasibility Studies] ... with a "no barriers" approach. Applicants are asked to demonstrate that there are no known technical or economic barriers which would prevent the installation and operation of their chosen CCS technologies". In addition, "Government does not intend to prescribe the detail of how CCS technology is applied in individual cases"*.

Therefore, although the proposed CO2 capture technology used as the basis for this Document pertains to a specific type of pre-combustion CO2 technology and a specific type of post-combustion CO2 technology, this is not considered to preclude the use of a different CO2 capture technology in the future.

In addition, it should be noted the values presented in this Document are indicative values. The values presented are based on generic and / or modelled information in respect of the CO2 capture technology currently proposed, and as such are sufficient for assessing the environmental impacts of the Project.

4.2 Description of Proposed CO2 Capture Technology

IGCC Power Plant with Pre-Combustion CO2 Capture

When operating as an IGCC power plant, a variety of fuel mixtures may be used to allow the gas turbine to be fired on syngas. The variety of fuel mixtures include coal, either as a sole fuel or co-fired with petcoke or biomass (including as a sole fuel), which are subjected to pre-combustion treatment producing the syngas.

Accordingly, and as noted previously, when operating in IGCC power plant mode, the generating station would be fired on syngas produced by:

a) The gasification of coal (or other fossil fuel / mixture of fossil fuels with biomass) with CO2 capture;

b) The gasification of coal (or other fossil fuel / mixture of fossil fuels with biomass) but without CO2 capture which may only take place in the circumstances allowed by the

UK Government under the proposed terms of Clause 38 of the Energy Bill which is currently before the UK Parliament (or similar provision); or,

c) The gasification of torrefied biomass as a sole fuel without CO2 capture (as this is not required UK Policy).

This Document assesses the proposed CO2 capture technology in accordance with the requirements of the CCR Guidance and Draft Supplementary Guidance.

Accordingly, whilst the selection and mixture of fuels has not yet taken place, this Document assumes operation in IGCC power plant mode fired on syngas produced by the gasification of coal (or other fossil fuel / mixture of fossil fuels with biomass) with CO2 capture. This is undertaken such that, for the purposes of this Document, a 'worst-case' scenario is assumed such that there is conservatism in the sizing of the capture, transportation and storage chain.

Figure 2 shows a schematic representation of the IGCC power plant with CO2 capture principle / pre-combustion CO2 capture technology.

The pre-combustion CO2 capture technology / IGCC power plant with CO2 capture principle comprises partial combustion (controlled oxidation) of a solid fuel in a gasifier. The partial oxidation produces a flammable syngas mixture which (at this stage) primarily consists of carbon monoxide (CO) and hydrogen (H2). The gasifier (marked (14) in Figure 2) consists of a pressurised vessel containing a gasification chamber and solid fuel injectors. The gasifer operates at a temperature between 1400°C to 1700°C. Oxygen for the gasifer is provided from an Air Separation Unit (ASU) (marked (20) in Figure 2).

The flammable syngas mixture is then scrubbed to remove any remaining solids and water-soluble gases (e.g. hydrochloric acid (HCl) and ammonia (NH3)). Then, to enable CO2 capture, the flammable syngas mixture is then passed through a CO2 shift reactor where water combines with the CO to produce carbon dioxide (CO2) and additional H2.

Following the CO2 shift reactor, the flammable syngas mixture is cooled to approximately 40°C and passed through an activated carbon filter (to remove traces of mercury and other substances) before being delivered to the acid gas and CO2 removal unit (marked (16) in Figure 2).

Within the acid gas and CO2 removal unit, the acid gases and CO2 are initially absorbed by a solvent solution. The resulting rich solvent solution is then passed through a selective regeneration process where the acid gases and CO2 are removed as separate streams and the lean solvent solution is recycled.

The captured acid gases will mainly comprise sulphur compounds (principally hydrogen sulphide) which will be converted to elemental sulphur, which it is intended be sold as a commercial by-product. The captured CO2 will pass to compression units.

The resulting syngas (comprising approximately 80 to 90 per cent H2) stream is then mixed with pure nitrogen (N2) (from the ASU (marked (20) in Figure 2)) before passing to the gas turbine (marked (1) in Figure 2). The syngas is mixed with N2 to control the fuel gas composition to within the tolerances for optimum firing efficiency prescribed by the manufacturer of the gas turbine, and to control NOx emissions.

Within the combustion chamber(s) of the gas turbine, the fuel gas is mixed with hot air from the compressor and the resulting combustion produces hot gases which are expanded across the turbine blades, turning the turbine rotor, which is directly coupled to the gas turbine generator, thus generating electrical power.

As the hot exhaust gases will still contain recoverable energy, the hot gases are routed through a Heat Recovery Steam Generator (HRSG) (marked (4) in Figure 2) to generate steam. The steam, produced at several pressure levels, is passed to the steam turbine (marked (2) in Figure 2) where the steam is expanded across the steam turbine blades, turning the turbine rotor, which is directly coupled to the steam turbine generator, thus generating additional electrical power. The expanded steam leaving the steam turbine will pass through a condenser and be returned to the HRSGs.

The use of gas turbines and steam turbines in a combined cycle increases the overall efficiency of the generating station.

When CO2 capture is not required, the CO2 shift reactor would be by-passed.

CCGT Power Plant with Post Combustion CO2 Capture

The post-combustion CO2 capture technology on which the technical assessments are based is a solvent based capture technology and consists of the following main process stages:

- Flue gas cooling;
- CO2 absorption;
- CO2 stripping;
- Flue gas discharge;
- CO2 discharge; and
- CO2 compression.

A schematic of the post-combustion CO2 capture technology can be seen in Figure 9 and a brief description is provided here.

For post-combustion, the flue gases are compressed then cooled in a direct contact cooler for processing in the CO2 capture plant.

After cooling, the flue gas passes through an absorber column where it comes into contact with the liquid amine solvent.

In the absorber column, the CO2 in the flue gas is chemically absorbed through acid-base neutralisation reactions with the amine solvent. This creates a CO2 rich stream of liquid amine solvent. The CO2 rich amine solvent is pumped out of the absorber column and is heated in a heat exchanger before entry into a stripper column.

In the stripper column, the CO2 rich amine solvent is heated further by the condensation of steam in a reboiler. As the amine can absorb less CO2 at higher temperatures, upon heating the amine solvent releases the CO2 as a gas. The lean liquid amine solvent is pumped from the bottom of the stripper column, cooled in the heat exchanger and further cooled before re-entry to the absorber column.

The CO2 gas, containing a large quantity of steam, exits at the top of the stripper column. 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 CO2 capture plant.

This CO2 capture technology can result in an end CO2 purity of over 99% based on the experience from similar technologies in the chemical processing industry.

If amine such as MEA is in contact with CO_2, the CO_2 will react with the amine and chemically absorb into it. The CO_2 capture process is driven by the fact that at lower temperatures more CO_2 will absorb into the amine than at higher temperatures. Therefore, in principle, CO_2 is absorbed by cold amine and released when the amine is heated.

In modern amine-based CO_2 capture processes, the stripper column operates at approximately 150°C. Temperatures higher than this will thermally degrade the amine. In theory, the absorber column can operate at any temperature below the stripper temperature. However, the larger the temperature difference between the two, the more CO_2 can be captured.

Indicative figures indicate an absorber column temperature of 35°C and a stripper column temperature of 150°C will enable a CO_2 capture rate of 90%. Actual values will depend on various other parameters of the CO_2 capture process, such as:

- The particular amine used;
- The CO_2 capture process temperature;
- The pressure in the absorber column and stripper;
- The residence time (i.e., the length of time the amine is in contact with the flue gas);
- The percentage of CO_2 in the flue gas; and,
- The amount of other substances.

4.3 Performance of Proposed CO2 Capture Technology

Table 4.1 shows an estimated performance of the generating station operating as an IGCC power plant fired on coal with CO_2 capture (with compression to 120 bar a) and a CCGT power plant fired on natural gas with post-combustion CO_2 capture. For the purposes of comparison, Table 4.1 also shows an estimated performance of the generating station operating as:

a) A CCGT power plant fired on natural gas, with dry low NOx (DLN) combustors in the gas turbine (i.e. prior to addition of post combustion or conversion to an IGCC power plant[12]);

b) An IGCC power plant fired on coal without CO_2 capture, with diffusion combustors in the gas turbine; and,

c) An IGCC power plant fired on biomass (torrefied biomass) without CO_2 capture, with diffusion combustors in the gas turbine.

[12] *After conversion of the CCGT power plant to an IGCC power plant, the DLN combustors would be replaced with diffusion combustors. The diffusion combustors will require steam injection for control of nitrogen oxides. Accordingly, the use of diffusion combustors will reduce the net electrical output and increase the heat rate.*

Table 4.1 - Estimated Performance of the Generating Station

Description	*Net Electrical Power Output* *(MW)*	*Approximate Net Electrical Efficiency (%)*		*Total CO2 Produced* *(kg/MWh)*	*Net CO2 Emitted* *(kg/MWh)*	*CO2 Captured (kg/MWh)* *[% CO2 Capture]*
		Lower Heating Value *(LHV)*	*Higher Heating Value* *(HHV)*			
IGCC power plant fired on coal with CO2 capture	418	38.0	36.3	823	101	722 [88]
CCGT power plant fired on natural gas with CO2 capture[13]	428	50.9	45.9	339	34	305 [90]
CCGT power plant fired on natural gas[14]	468	57.2	51.7	352	352	0 [0]
IGCC power plant fired on coal without CO2 capture	433	42.9	41.0	731	731	0 [0]
IGCC power plant fired on biomass (torrefied	445	43.3	41.4	712	712	0

[13] *Assuming the auxiliary power demand for the CO2 Capture technology is ~10% [link]*
[14] *Modelled as gas-fired with DLN combustors for control of nitrogen oxides, prior to conversion to an IGCC power plant.*

Description	***Net Electrical Power Output (MW)***	***Approximate Net Electrical Efficiency (%)***		***Total CO2 Produced (kg/MWh)***	***Net CO2 Emitted (kg/MWh)***	***CO2 Captured (kg/MWh) [% CO2 Capture]***
		Lower Heating Value (LHV)	***Higher Heating Value (HHV)***			
biomass) without CO2 capture						[0]

When operating as an IGCC power plant with CO2 capture, up to circa. 88 per cent of CO2 will be captured.

When operating as a CCGT power plant with post-combustion CO2 capture, up to circa. 90 per cent of CO2 will be captured.

In this regard, whilst the total quantity of CO2 captured per annum will be dependent upon the operating regime (including operational load factors and availability), for the purposes of this calculating the total amount of CO2 that needs to be captured, a 'worst-case' scenario has been assumed (i.e. operation for 100 per cent of the year) such that there is an inherent conservatism assumed for the sizing of the capture, transportation and storage chain.

Therefore, based on these assumptions, the sizing of the capture, transportation and storage chain for the IGCC power plant with pre-combustion capture and CCGT power plant with post-combustion capture are based on the information presented in Table 4.2 and 4.3 respectively.

Table 4.2 - Sizing of Capture, Transportation and Storage Chain for IGCC Power Plant with Pre-Combustion CO2 Capture

	Units	*Amount*
Total CO2 Produced	kg/MWh	823
% CO2 Captured	%	88
CO2 (net) Emitted	kg/MWh	101
CO2 Captured / Compressed / Transported / Stored (Assuming a worse case of full load and 100 per cent availability)	kg/MWh	722
	tonnes (millions)/year	2.6
Total CO2 Transported / Stored (Assuming 30 years of capture)	tonnes (millions)	79.3

Table 4.3 - Sizing of Capture, Transportation and Storage Chain for CCGT Power Plant with Pre-Combustion CO2 Capture

	Units	*Amount*
Total CO2 Produced	kg/MWh	339
% CO2 Captured	%	90
CO2 (net) Emitted	kg/MWh	34.0
CO2 Captured / Compressed / Transported / Stored (Assuming a worse case of full load and 100 per cent	kg/MWh	305
	tonnes	1.1

	Units	Amount
availability)	(millions)/year	
Total CO2 Transported / Stored (Assuming 30 years of capture)	tonnes (millions)	33.7

4.4 Product Specifications for the Proposed CO2 Capture Technology

During operation of an IGCC power plant with CO2 capture, efficient operation of the gas turbine will require careful control of the chemical composition of the gaseous fuel.

Accordingly, Table 4.4 detail typical specifications for the proposed CO2 capture technology.

Table 4.4 - Typical Composition of Gas Entering the Pre-Combustion CO2 Capture Technology

Component	*% Volume*
Carbon monoxide (CO)	0.7
Carbon dioxide (CO2)	37.9
Hydrogen (H_2)	57.1
Hydrogen sulphide (H_2S)	0.2
Water (H_2O)	0.2
Nitrogen (N_2)	3.3
Argon (Ar)	0.6

Table 4.5 - Typical Composition of Gas Leaving the Pre-Combustion CO2 Capture Technology (and Delivered to the Gas Turbine) (Before Dilution)

Component	*% Volume*
Carbon monoxide (CO)	1.1
Carbon dioxide (CO2)	6.0
Hydrogen (H_2)	86.9
Nitrogen (N_2)	5.1
Argon (Ar)	0.9

4.5 Flue Gas Clean Up

CCGT Power Plant (No CO2 capture)

When operating as a CCGT power plant, the gas turbine within the generating station would operate on natural gas. As such, the gas turbine would incorporate proven pollution control technology to limit the production of nitrogen oxides (NOx) to a maximum of 50 mg/Nm3 (at reference conditions, as required by the LCPD / IED when gas turbine outputs are above 70 per cent load). The pollution control technology, known as DLN combustion, represents the Best Available Technique (BAT) for limiting emissions of NOx to the atmosphere from CCGT based power plants.

However, DLN combustors are not yet capable of burning very high hydrogen fuels and so will not be suitable when operating as an IGCC power plant.

IGCC Power Plant

When operating as an IGCC power plant, the gas turbine within the generating station would operate on syngas. As such, the gas turbine would require retrofitting with non-DLN diffusion combustors. However, the gas turbine within the generating station would also retain the capability to operate on natural gas.

Non-DLN diffusion combustors require a diluent to prevent the formation of high levels of NOx. During operation on syngas it has been assumed that nitrogen, produced by the ASU, would be used. During operation on natural gas it has been assumed that steam, extracted from the steam cycle, would be used.

The effect on performance during operation on syngas with nitrogen dilution and operation on natural gas with steam injection has been included in the thermodynamic modelling referenced in this Document.

When operating without CO2 capture (i.e. with the CO2 shift reactor bypassed) the syngas delivered to the gas turbine will have a much lower hydrogen content, and LHV, and so will require a much lower N2 dilution rate. The N2 dilution rate would be dependent on composition, ambient conditions and load, and therefore would require confirmation through detailed combustion testing and mapping. However, for the purposes of this Document the N2 dilution rate has been reduced such that fuel / N2 mix delivered to the gas turbine has a similar LHV, both by volume and mass.

4.6 Integration of Proposed CO2 Capture Technology

For operation of an IGCC power plant with CO2 capture, a number of integrations would be necessary. Typical heat and power integrations (or interfaces) can be seen, respectively, in Table 4.6 and Table 4.7.

Table 4.6 - Heat Integration During Operation of the IGCC Power Plant with CO2 Capture

No.	*Integration*	*Heat Transfer to Water / Steam Cycle (MJ/s)*	*Source*	*Return*
1	Syngas Cooling	55.7	Condensate Extraction Pump Discharge	Feedwater Tank
2	Shift Reaction Cooling	72.5	Low Temperature Economizer Exit	HP Evaporator (Dry Saturated Steam)
3	Steam Supply for	-27.2	IP Superheater	None - Reactant for

No.	Integration	Heat Transfer to Water / Steam Cycle (MJ/s)	Source	Return
	Shift Reaction			Shift Reaction
4	CO2 Capture Reboiler	-7.8	LP Superheater	Feedwater Tank
5	Gasifier Steam	-11.2	HP Evaporator	None
6	Syngas Cooling	8.8	IP Economizer Exit	IP Evaporator (Dry Saturated Steam)
Net Heat Transfer to Water / Steam Cycle		**90.8**		

Table 4.7 - Power Integration During Operation of the IGCC Power Plant with CO2 Capture

No.	Integration	% of Gross Electrical Power Generated
1	CO2 Capture and AGR Requirements	5.6
2	ASU	9.5

For operation of a CCGT power plant with post-combustion CO2 capture, a number of integrations would be necessary. Typical heat integrations (or interfaces) can be seen, respectively, in Table 4.8.

Table 4.8 - Heat Integration During Operation of the CCGT Power Plant with CO2 Capture

No.	Integration	Heat Transfer to Water / Steam Cycle (MJ/s)	Source	Return
1	Quench Water Cooling (x2)	53.9	Cooling Tower Water System	Cooling Tower Water System
2	Lean Solvent Cooler (x2)	59.53	Cooling Tower Water System	Cooling Tower Water System
3	Desorber Top Condenser	12.5	Cooling Tower Water System	Cooling Tower Water System
4	Desorber Reboiler	-118.42	Steam Water System	Steam Water System
5	C02 Compressor	18.58	Cooling Tower Water System	Cooling Tower Water System
Net Heat Transfer to Water / Steam Cycle		**139.52**		

4.7 Block Flow Diagram

A Block Flow Diagram and Cycle Flow Schematic of an IGCC power plant with CO2 capture are provided in Insert 4.1 and Insert 4.2 respectively.

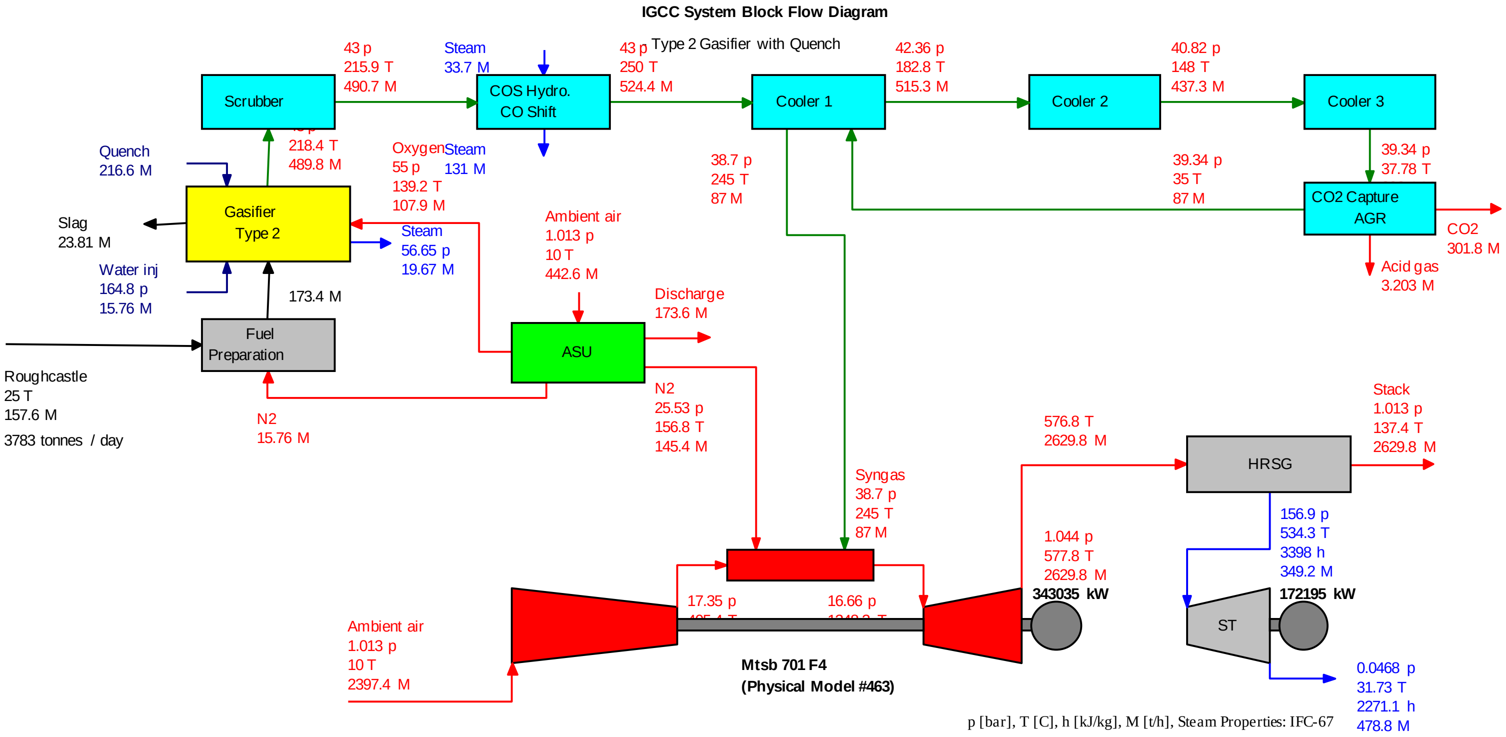
For comparison, a Block Flow Diagram and Cycle Flow Schematic of a CCGT power plant with post-combustion CO2 capture are provided in Insert 4.4 and Insert 4.5 respectively.

4.8 Heat and Material Balance

A Heat and Material Balance of an IGCC power plant with CO2 capture is provided in Insert 4.3.

For comparison, a Heat and Material Balance of a CCGT power plant with post-combustion CO2 capture is provided in Insert 4.6.

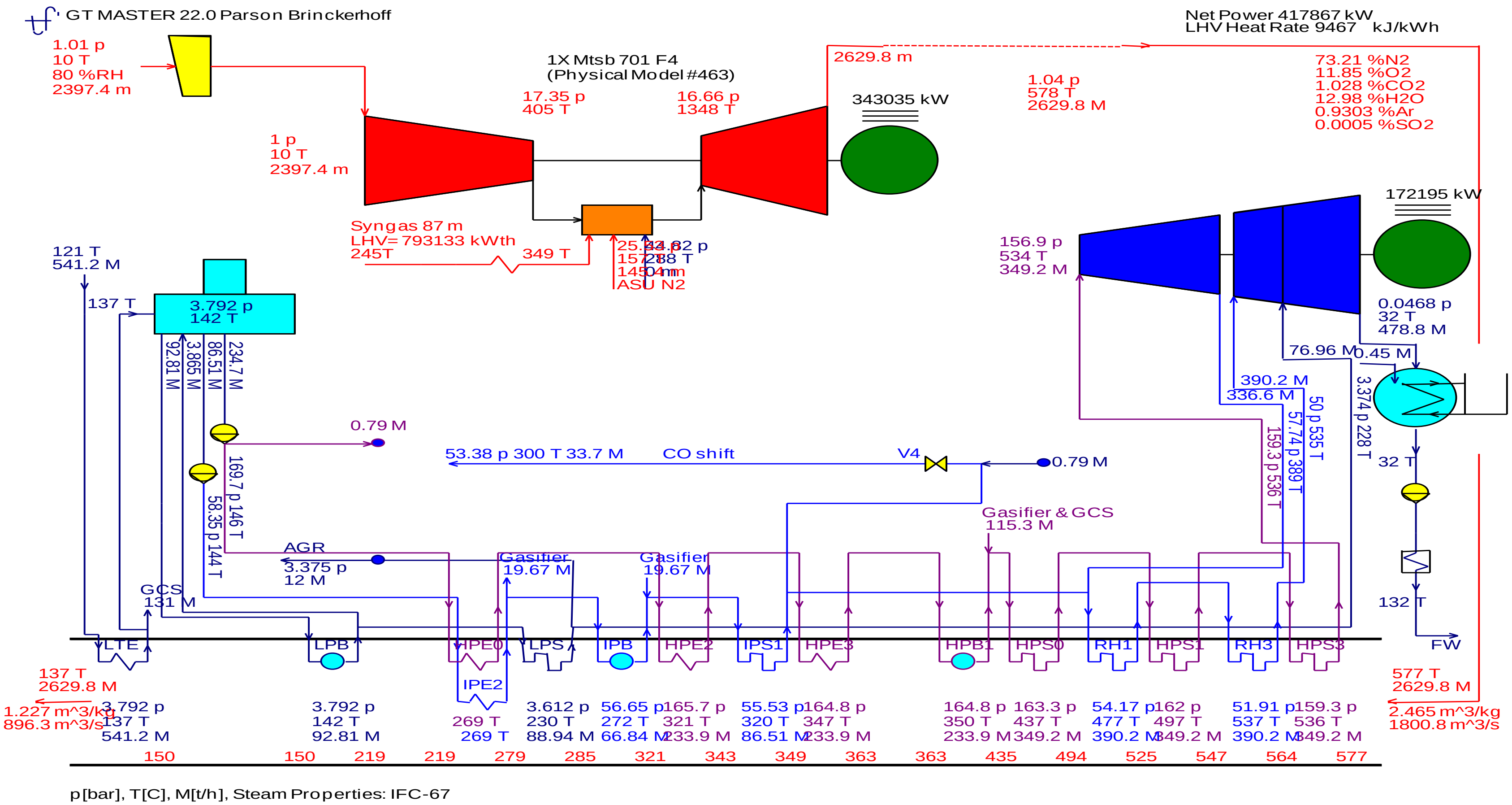
Insert 4-1 - Block Flow Diagram for IGCC Power Plant with Pre-Combustion CO2 Capture



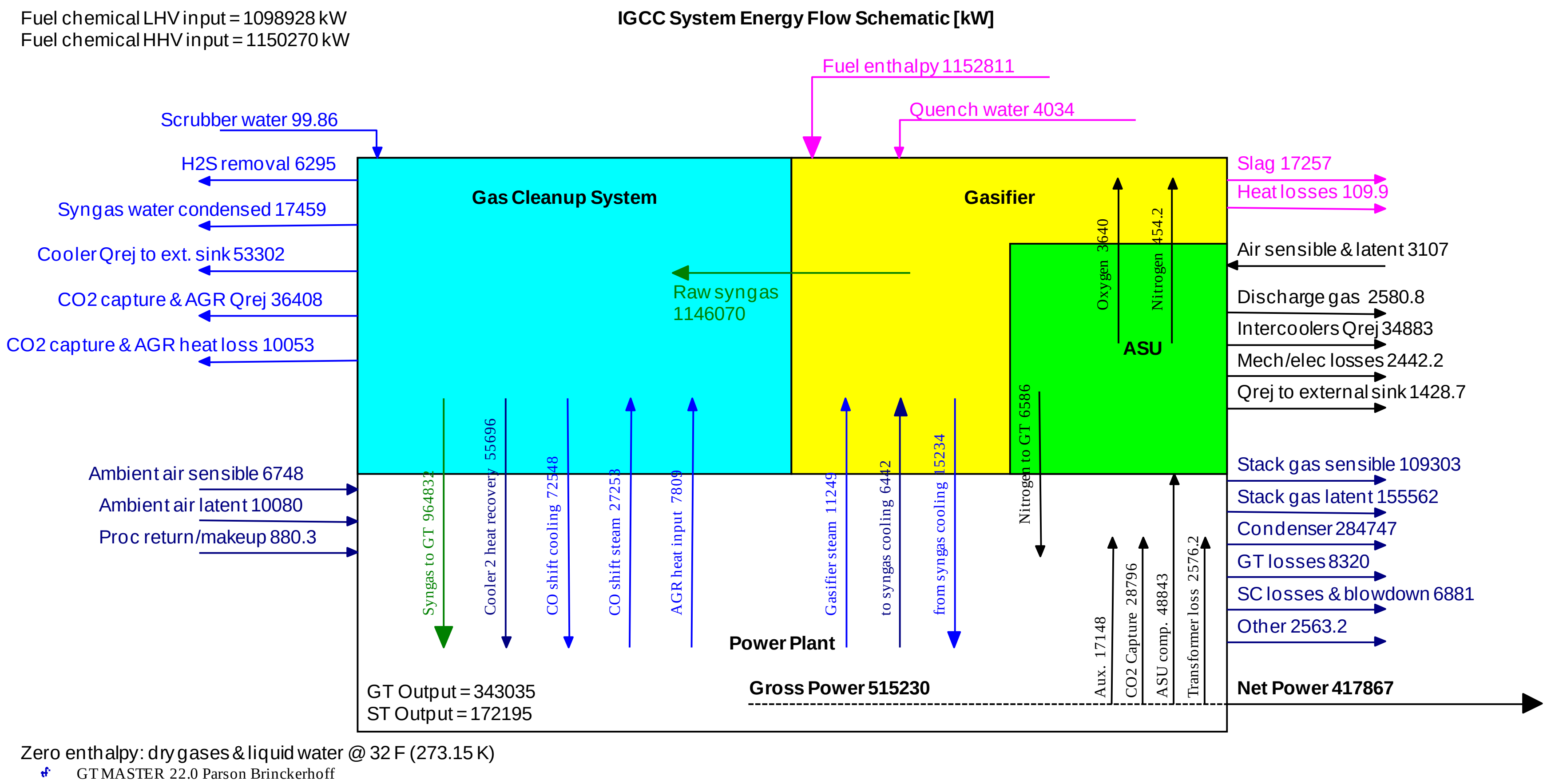
GT MASTER 22.0 Parson Brinckerhoff

Gross Power = 515230 kW, Net = 417867 kW
LHV Gross Heat Rate = 7678, Net = 9467 kJ/kWh
LHV Gross Electric Eff. = 46.88 %, Net = 38.02 %
HHV Gross Electric Eff. = 44.79 %, Net = 36.33 %

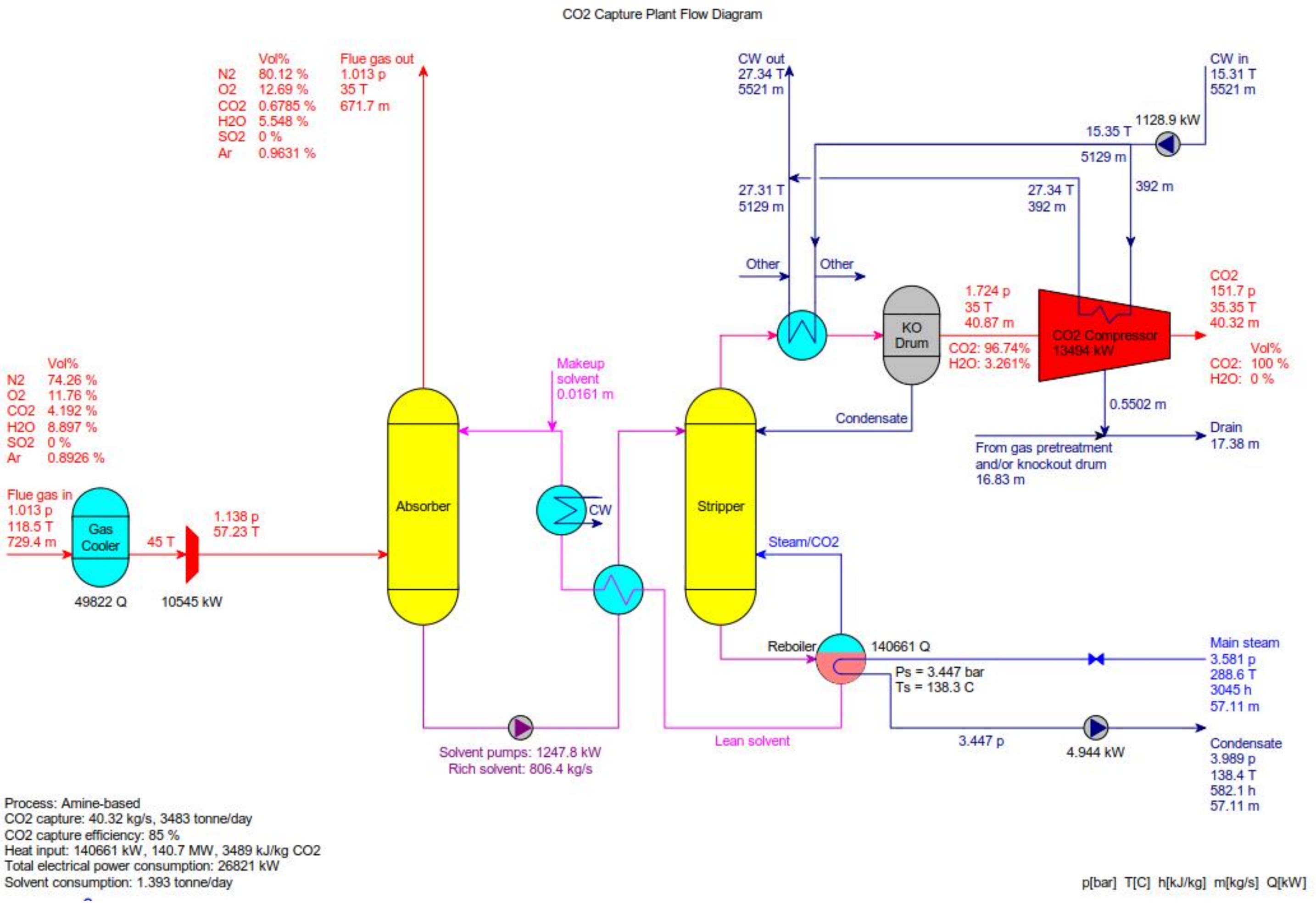
Insert 4-2 - Cycle Flow Schematic for IGCC Power Plant with Pre-Combustion CO2 Capture



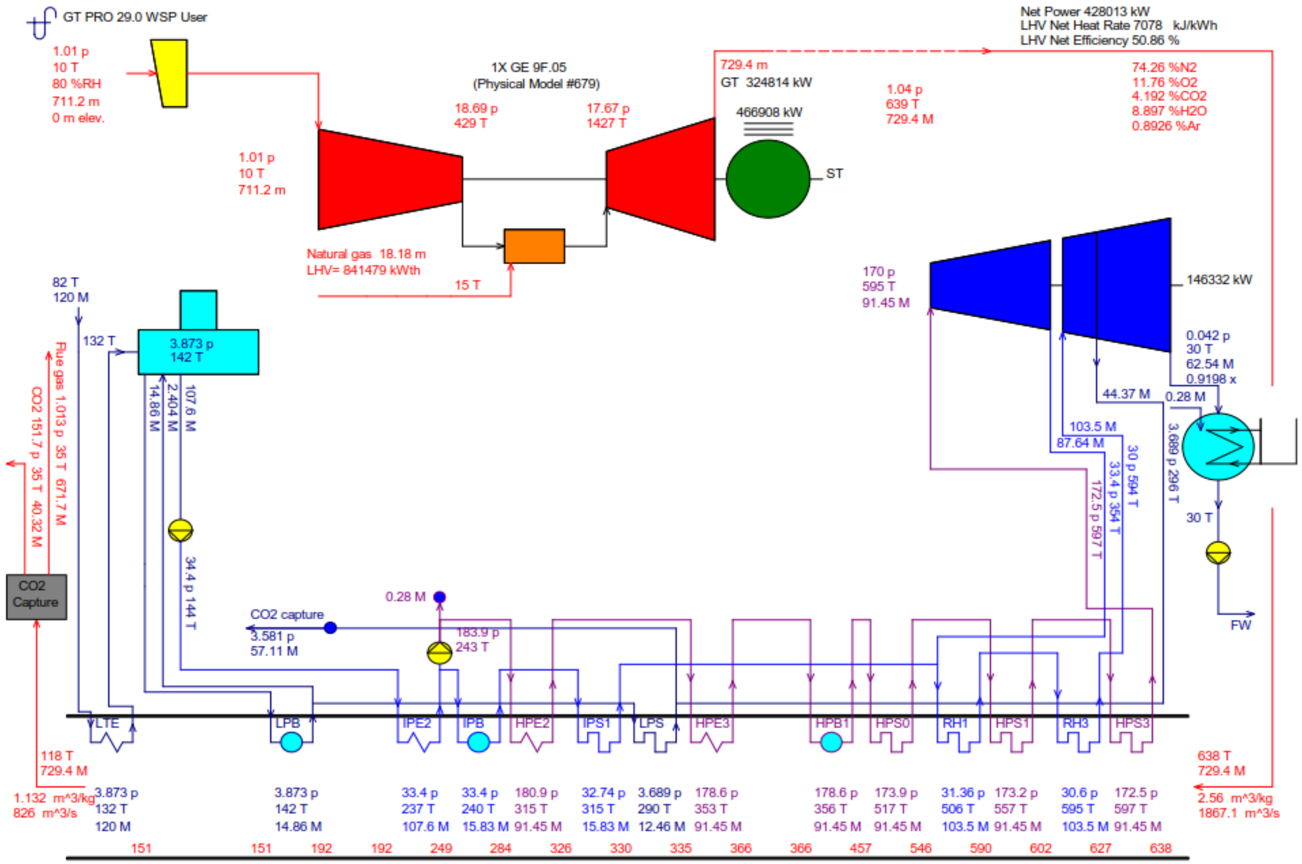
Insert 4-3 - Heat & Material Balance for IGCC Power Plant with Pre-Combustion CO2 Capture



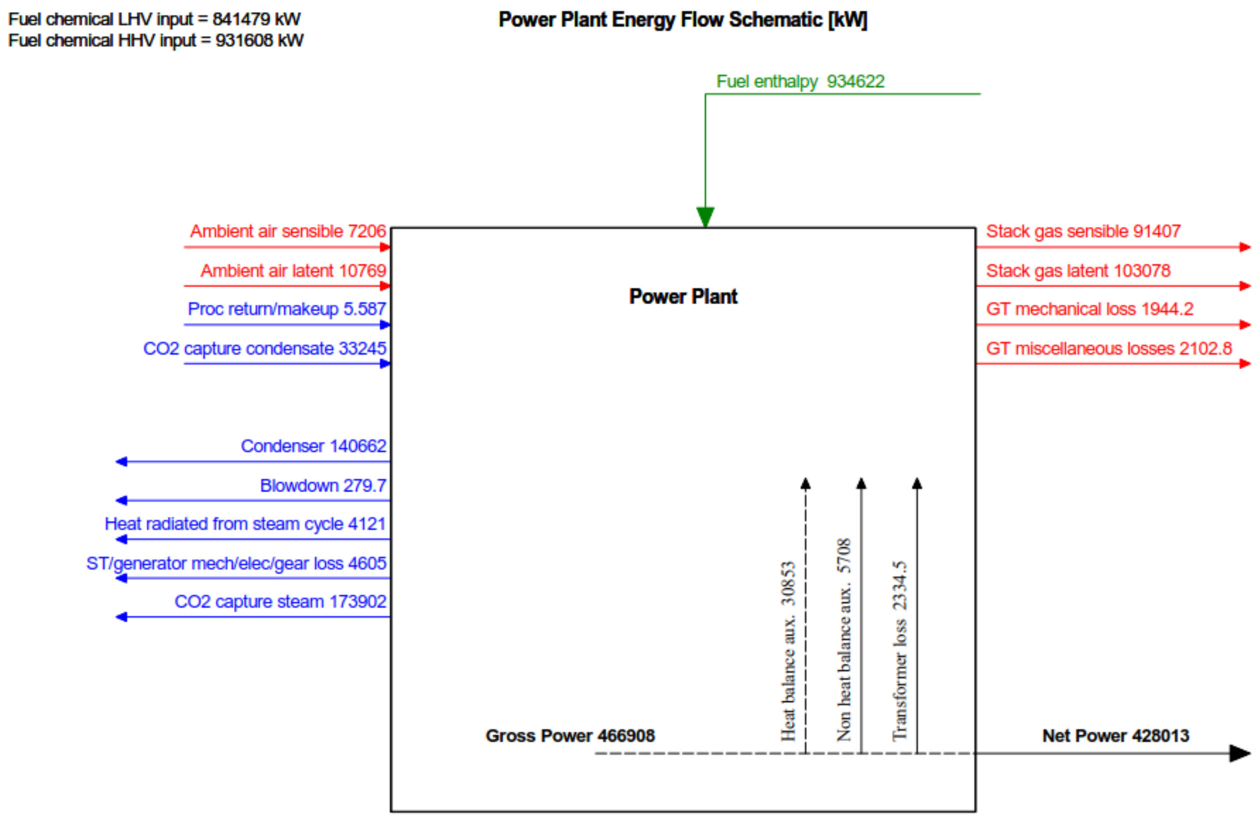
Insert 4-4 - Block Flow Diagram for CCGT Power Plant with Pre-Combustion CO2 Capture Plant



Insert 4-5 - Cycle Flow Schematic for CCGT Power Plant with Pre-Combustion CO2 Capture



Insert 4-6 - Heat & Material Balance for CCGT Power Plant with Pre-Combustion CO2 Capture



5 TECHNICAL ASSESSMENT - SPACE

Alongside the information provided in the 2013 Submission on IGCC pre-combustion, this section has been updated to include details of the space provision required for Post-Combustion CO2 Capture technology. Similar to the 2013 Submission, the assessment has been carried out in accordance with the CCR Guidance and demonstrates sufficient space has been reserved based on the net power output for the plant.

5.1 Tracing of Space Requirement

According to the DECC Consultation Response[15] (paragraph 2.21), Table 1 of the CCR Guidance (Approximate Minimum Land Footprint for some types of CO_2 Capture Plant) is intended to "*provide applicants, local authorities and statutory advisors with an approximate indication of the scale of carbon capture equipment which may be necessary*". That is, it is intended to provide an indication of the space requirement. Table 1 of the CCR Guidance is based on "*net plant capacities of around 500 MW*".

Table 1 from the CCR Guidance is reproduced in Table 5-1, with inclusion of an additional row to provide total size footprint in hectares (ha). The dimensions regarding space requirements related to this report are highlighted red.

Table 5.1 - Table 1 from the CCR Guidance (Approximate Minimum Land Footprint for some Types of CO2 Capture Plant) (Adapted)

	COLUMN 1	***COLUMN 2***	***COLUMN 3***	***COLUMN 4***	***COLUMN 5***	***COLUMN 6***
	CCGT with Post-Combustion Capture	***CCGT with Pre-Combustion Capture***	***CCGT with Oxy-Combustion***	***USCPF with Post-Combustion Capture***	***IGCC with Capture***	***USCPF with Oxy-Combustion***
Site Dimensions – Generation Equipment (m)	170 x 140	170 x 140	170 x 140	400 x 400	475 x 375	400 x 400
Site Dimensions – CO_2 Capture Equipment (m)	250 x 150	175 x 150	80 x 120	127 x 75		80 x 120
Total Site Footprint (m^2)	62 000	50 000	34 000	170 000	180 000	170 000
Total Site	6.2	5.0	3.4	17.0	18.0	17.0

[15] *Carbon Capture Readiness (CCR): Government's Response to the Consultation Response (November 2009). Department of Energy and Climate Change.*

	COLUMN 1	COLUMN 2	COLUMN 3	COLUMN 4	COLUMN 5	COLUMN 6
	CCGT with Post-Combustion Capture	***CCGT with Pre-Combustion Capture***	***CCGT with Oxy-Combustion***	***USCPF with Post-Combustion Capture***	***IGCC with Capture***	***USCPF with Oxy-Combustion***
Footprint (ha)						

Acronyms: CCGT – Combined Cycle Gas Turbine; IGCC – Integrated Gasification Combined Cycle; USCPF – Ultra Supercritical Pulverised Fuel

Examination and tracing of the origin of the table included in an Imperial College Paper[16] has allowed for identification of the following facts for the space requirement for a "*CCGT with post-combustion capture*":

a) Table 1 (column 1) originates from the IEA GHG Study 2005/117, and should relate to a 785 MW CCGT power plant and not a 500 MW CCGT power plant; and,

b) Table 1 (column 1) therefore provides an incorrect space requirement which should be reduced.

With this in mind, it may also be the case that other columns of the table are based on incorrect capacities for the space requirements they quote. This has also been suggested by the Imperial College Paper.

Corrected information for column 1 and column 5 of Table 1 within the CCR Guidance has been presented in Table 5-2 below.

Table 5.2 – Updated footprints for a CCGT with Post-Combustion Capture and a IGCC Power Plant with CO2 Capture

	COLUMN 1	COLUMN 5
	CCGT with Post-Combustion Capture	***IGCC Power Plant with CO_2 Capture***
Net MW Generating Capacity	785	785
Site Dimensions – Generation Equipment (m)	170 x 140	170 x 140 *
Site Dimensions – CO_2 Capture Equipment (m)	250 x 150	475 x 375
CO2 Capture Footprint (m^2)	37,500	178,125

[16] *Assessment of the validity of "Approximate minimum land footprint for some types of CO_2 capture plant" provided as a guide to the Environment Agency assessment of Carbon Capture Readiness in DECC's CCR Guide for Applications under Section 36 of the Energy Act 1998, Imperial College, 2010*

[17] *IEA Greenhouse Gas R&D Programme (IEA GHG), "Retrofit of CO_2 capture to natural gas combined cycle power plants", 2005/1, January 2005*

	COLUMN 1	*COLUMN 5*
	CCGT with Post-Combustion Capture	***IGCC Power Plant with CO_2 Capture***
CO2 Capture Footprint (ha)	3.75	17.8

* The plot space for the reference CCGT power plant is 170 m x 140 m (i.e. 2.4 ha). Incorrectly excluded from Table 1 within the CCR guidance.

5.2 IGCC Power Plant with Pre-Combustion CO2 Capture

Based on the information in Table 5-2 *("COLUMN 5")*, it can be seen that a 785 MW (net) CCGT power plant which is converted to an "*IGCC with capture"* would require (in addition to the plot space for the CCGT power plant itself) 17.8 ha of space for the CO_2 capture plant.

Table 5-3 presents space requirements for a 470 MW (net) CCGT power plant that is converted to an IGCC plant with pre-combustion carbon capture.

Table 5.3 - Space Requirements for a 470 MW IGCC Power Plant with CO2 Capture

	IEA Study 2005/1 – COLUMN 5 (Table 5.2)	***Scaled for this Project – IGCC Pre-Combustion Capture***
Net MW Generating Capacity	785	470
CO2 Capture Footprint (m^2)	178,125	107,000
CO2 Capture Footprint (ha)	17.8	10.7

Table 5-3 indicates the minimum area that is required to be reserved under the CCR Guidance is 10.7 ha. The DCO includes the IGCC Plant equipment (Work No. 2a (gasification facility) and Work No. 2b (flare stack)), which covers an area of 12.6 ha. The total extent of the land provided for IGCC pre combustion plant and the equipment layout is shown in Figure 3.

5.3 CCGT Power Plant with Post-Combustion CO2 Capture

Based on the information in Table 5-2 *("COLUMN 1")*, it can be seen that a 785 MW (net) CCGT power plant which is retrofitted to include post-combustion carbon capture would require (in addition to the plot space for the CCGT power plant itself) 3.75 ha of space.

Table 5-4 presents space requirements for a post-combustion carbon capture plant retrofitted for a 470 MW (net) CCGT power plant.

Table 5.4 - Space Requirement for a Post-Combustion Carbon Capture Plant Retrofitted onto a 470 MW (Net) CCGT Power Plant

	IEA Study 2005/1 – COLUMN 1 (Table 5.2)	***Scaled for this Project – CCGT Plant - Post-Combustion Capture***
Net MW Generating Capacity	785	470
CO2 Capture Footprint (m^2)	37,500	22,452
CO2 Capture Footprint (ha)	3.75	2.25

Table 5-4 indicates the minimum area that is required to be reserved under the CCR Guidance is 2.25 ha. The actual CCR land allocation provided for this Project is a more conservative 2.3 ha. The 2.3 ha reserved area is shown in Figure 10. The reserved area is split over two Work Nos. within the Operations Area. The majority of the post-combustion reserve area is within Work No. 2b and the remaining is within a proportion of Work No. 2a (gasification facility). There is no conflict with locating the post combustion reserve area within the pre-combustion IGCC Plant areas of Work No. 2a and Work No. 2b because, if one solution develops, the other solution becomes redundant.

5.4 Outline Plot Level Plan / Preliminary Plot Plan

In addition to meeting the minimum space requirements in accordance with the CCR Guidance, it is equally important to demonstrate that the space allocated can physically accommodate the CO_2 capture plant / equipment.

IGCC power plant with pre-combustion CO2 capture

The preliminary plot plan for the Operations Area of the IGCC power plant with pre-combustion CO2 capture can be seen in Figure 3.

Accordingly, at the point of construction / conversion to an IGCC power plant with CO_2 capture, the preliminary plot plan would principally comprise the following (with reference to the numbers on Figure 3):

a) Gasifier (14);

b) Syngas Treatment and Conditioning Equipment (15);

c) Acid Gas Removal Equipment (16);

d) Sulphur Recovery and Tail Gas Treatment (17, 18);

e) Waste Water Treatment Plant (19)

f) Air Separation Unit (20);

g) Nitrogen Storage Tank(s) (21);

h) Oxygen Storage Tank(s) (22);

i) Flare Stacks (23);

j) Covered Solid Fuel Storage Area (24);

k) Fuel Milling / Drying / Preparation Equipment (25); and,

l) Solid Waste Removal Equipment and Storage (26, 27).

In addition to the preliminary plot plan, indicative 3D renderings of the Project operating as an IGCC power plant can be seen in Figure 4 (view from the south west) and Figure 5 (view from the north west).

CCGT Power Plant with Post-Combustion CO2 Capture

The preliminary plot plan for the post-combustion carbon capture plant retrofitted onto the CCGT power plant can be seen in Figure 10. The equipment indicated in the plot plan have been sized based on a CO2 capture plant processing flue gas from a Siemens SGT5-8000H gas turbine as provided by Siemens. The gas turbine to be used for this Project is smaller (reduced mass flue gas flow) and so the plant equipment has been scaled using an appropriate scaling factor.

The post-combustion plant would principally comprise the following plant items:

a) Flue Gas Coolers

b) Flue Gas Blower;

c) Absorber Column;

d) Stripper Column;

e) Unloading/Loading Storage;

f) Electrical Power / Steam Condensate Area;

g) CO_2 Compression Plant Area;

h) Admin Building(s);

i) Utilities and Balance of Plant Area;

j) Areas for Coolers, Heat Exchangers and Flash Compressor Units.

5.5 CCR Status and Full Development of CCS

As required by the CCR Guidance, this ‘Technical Assessment – Space’ will be reviewed on an ongoing basis as part of the carbon capture readiness monitoring report to be submitted every 2 years (from the first date of export of electricity / commercial operation of the CCGT power plant).

More specifically, with respect to the Amendment Order, each carbon capture readiness monitoring report must provide evidence of compliance with Requirement 36 as amended by the Amendment Order.

6 TECHNICAL ASSESSMENT - RETROFITTING AND INTEGRATION OF CO2 CAPTURE TECHNOLOGY

Alongside the information provided in the 2013 Submission, this section has been updated to include the retrofitting and integration required for the implementation of a CCGT Power Plant with Post-Combustion CO2 Capture technology. The updated information is comparative in detail to the information provided in the 2013 Submission, where applicable.

6.1 Introduction

In order for construction of CO_2 capture plant / equipment or to convert from a CCGT power plant to an IGCC power plant or to convert from a CCGT power plant to a CCGT power plant with carbon capture, a number of factors / elements need to be considered.

The majority of these factors / elements in relation to the technical feasibility of a proposal are set out in:

- Annex B of Carbon Capture Readiness (CCR) Guidance (November 2009) – "Environment Agency Verification of CCS Readiness New Natural Gas Combined Cycle Power Station Using Pre-Combustion CO2 Capture (including coal gasification) and Hydrogen-Rich Fuel Gas Combustion" (Refer to Appendix C)
- Annex C of the Draft Supplementary Guidance – (Environment Agency Verification of CCS Technical Feasibility: New Integrated Gasification Combined Cycle Power Station using Pre-Combustion CO2 Capture (Coal Gasification) and Hydrogen-Rich Fuel Gas Combustion)" (Refer to Appendix D).
- Annex C of Carbon Capture Readiness (CCR) Guidance (November 2009) – "Environment Agency verification of CCS Readiness New Natural Gas Combined Cycle Power Station Using Post-Combustion Solvent Scrubbing" (Refer to Appendix E)

In terms of the retrofitting and integration of CO2 capture technology, this Section provides the information required by the Annexes.

6.2 Gas Turbine

IGCC Power Plant with Pre-Construction CO2 Capture

When operating as an IGCC power plant, the gas turbine within the generating station would be able to operate on syngas. As such, the gas turbine would be fitted / retrofitted with non-DLN diffusion combustors. They would also retain an ability to operate on natural gas.

Non-DLN diffusion combustors require a diluent to prevent the formation of high levels of NOx. During operation on syngas it is assumed that nitrogen, produced by the ASU, would be used.

Following conversion of a CCGT power plant to an IGCC power plant fired on syngas, there would be a greater fuel / diluent flow. Therefore, the area of the first turbine stage would likely need to be modified (increased). During the detailed design stage, the requirements for this modification would be clearly defined.

CCGT Power Plant with Post-Combustion CO2 Capture

The following pressure drops are to be expected downstream of the gas turbine as a result of the HRSG and introduction of the new CCS plant include:

- The gas side pressure drops across the direct contact cooler and absorber column – typically 40 to 100 mbar; and
- The exhaust pressure drops across the HRSG and ducting – typically 30 to 35 mbar.

As such, the total gas side pressure drop is estimated to be at least 70 mbar.

Whilst the actual effect of pressure drop varies with specific gas turbine models, generally speaking, an increase in exhaust pressure reduces the gas turbine output and efficiency. It is therefore beneficial to keep the exhaust pressure for the gas turbine low. As an estimate, an increase in exhaust pressure of 25 mbar would result in a loss of electrical power output of approximately 5 MW.

As the maximum allowable gas turbine exhaust pressure drop is typically around 50 mbar, the design for the CO2 capture plant in this Feasibility Study has included a booster fan to overcome the additional pressure drop across the direct contact cooler and absorber column and across the HRSG and ducting. Whilst the booster fan power consumption versus the reduced power generated by the gas turbines will require some optimisation, the principal function of the fans is to prevent a high back pressure on the gas turbines, which could lead to tripping of the gas fired power plant.

Whilst it is not possible to provide specifications for the booster fan at this stage without performing a more detailed design of the CO2 capture plant, adequate provision of space has been provided on the CO2 capture plant for its installation. Therefore, based on the above, the relevant plant and equipment poses no problem in relation to retrofit and integration (subject to detailed design being carried out).

6.3 Heat Recovery Steam Generator (HRSG) and Steam Cycle

IGCC Power Plant with Pre-Combustion CO2 Capture

For future operation as an IGCC power plant, the HRSG, steam turbine and generator for the CCGT power plant would be sized to allow for the additional high pressure (HP) and intermediate pressure (IP) steam (generated by the gasifier), including for variations in pressure, temperature and flow. This is considered to be a more practicable solution than retrofitting major modifications. Therefore conversion / retrofit does not require consideration.

In addition, during operation as an IGCC power plant with CO2 capture, the low pressure (LP) steam required for CO2 capture would be provided from the HRSG (as opposed to a dedicated auxiliary boiler) to optimise efficiency.

During the detailed design stage, the required layout and capacity for the HRSG, steam cycle and generator would be clearly defined so as to enable this flexibility to be achieved.

CCGT Power Plant with Post-Combustion CO2 Capture

Steam is required for the stripping of CO2 from the amine solvent in the CO2 capture process.

The quantity of steam which will be required for the CO2 capture process will ultimately be dependent upon the chosen process provider and the specific technology selected.

The steam will be extracted from the steam cycle of the gas fired power plant. For the purpose of the Feasibility Study, it has been assumed that a largely standard power plant design is installed and then when required, CO2 capture technology is retrofitted into the design.

The steam could be extracted from the Cold Reheat (CRH) line or the Intermediate Pressure (IP) turbine exhaust. The suitability of each will depend on the final steam turbine configuration and design capability of the HRSG and steam turbine. At present it is considered likely that the steam turbine would have one of the following configurations:

- Option 1: Separate High Pressure (HP) turbine, IP turbine and a two-flow low pressure (LP) turbine with a lateral exhaust; or,
- Option 2: Combined HP / IP turbine plus separate two-flow LP turbine with lateral exhaust.

Other possible configurations are:

- Option 3: HP turbine, plus combined IP / LP turbine with an axial exhaust; or,
- Option 4: Single casing HP / IP / LP turbines with an axial exhaust.

In terms of extracting steam from the CRH line, steam can be extracted from the CRH line with any of the above options.

In terms of extracting steam from the IP turbine exhaust, for Options 1 and 2, with separate LP turbine cylinders, the steam exits the IP turbine and is delivered to the LP turbine via the LP crossover pipe. Therefore, in Options 1 and 2, a modified LP crossover pipe could be retrofitted, with an off-take port incorporated for the CO2 capture process. The design of this should be such that excessive forces, moments and stresses are not imposed on the LP crossover pipe and the turbine. This would not be possible for Options 3 and 4.

For the purpose of this assessment, it has been assumed that steam will be extracted from the CRH line, so all of the above options can be included. To allow retrofitting and integration, this would require space for an off-take port on the CRH line as well increasing the de-superheating capability. The layout and temperature profile of the reheater should also be checked to allow for the higher levels of de-superheating and to prevent overheating of the tubes. If this is employed, steam could be extracted and provided at any pressure up to the pressure of the CRH line. This would not require that an off-take port is provided from the steam turbine and is therefore independent of the choice of steam turbine manufacturer. Future retrofitting of the cold reheat line for supply of steam to the CO2 capture plant will be considered as part of the design.

However, the final decision on the option to implement and the location for the associated off-take port would come at the time of detailed design and installation of the CO2 capture plant. This would depend upon, but not restricted to the following:

- Fuel price;
- Carbon price;
- Electricity market conditions;
- Capital cost of retrofitting; and
- Age and condition of power plant (for example, it might be an opportune time to refurbish and / or upgrade the steam turbine).

In addition, extra steam might be required during some periods (e.g. if the CO2 capture process calls for the storage of rich amine during periods of high electricity prices and stripping during periods of low electricity prices). These options have not been considered in the base case design. However, it is recommended that these options are considered further during the detailed design of the steam system.

Based on the above, the relevant plant and equipment poses no problem in relation to retrofit and integration (subject to detailed design being carried out).

6.4 Water – Steam – Condensate Cycle

An indication of the required water / steam / condensate interfaces is shown in Table 4.8.

These interfaces can be sized and configured at the outset of the Project during the detailed design stage so as to enable the installation of CO2 capture apparatus. Therefore, they pose no problems in relation to retrofit or conversion

6.5 Fuel Gas Conditioning System

For operation as an IGCC power plant, the fuel gas (syngas) preparation system would comprise the following plant and activities:

a) Roller-type mills (similar to those used in a traditional coal-fired power plant) and an internal hot-gas generator are used to pulverise and dry the fuel. The roller-type mills would break down the solid fuel to pulverised fuel, which is of a size range suitable for efficient pneumatic transport and gasification. During the break down of the solid fuel, the internal hot-gas generator (generating a hot, inert gas stream) would dry the fuel (heating the water in the solid fuel so that it evaporates);

b) Following this process, the pulverised and dried fuel would be removed from the inert gas stream by bag filters or similar;

c) The pulverised and dried fuel would then be transported to the fuel pressurisation and feeding system;

d) The fuel pressurisation and feeding system would likely comprise: lock hoppers (where the fuel stream is pressurised with nitrogen); and, feed hoppers. The feed hoppers would receive the pressurised fuel / nitrogen stream mixture and feed the fuel / nitrogen stream mixture to the gasifier.

Information on the fuel gas conditioning system is provided in Section 4.4 (Product Specifications for the Proposed CO2 Capture Technology).

As described in Section 5, the area contained within the Operations Area (where it is anticipated the gasification and CO2 capture plant / equipment would be sited) is capable of accommodating the relevant plant / equipment described, which can be sized appropriately for the Project. Therefore, subject to detailed design being carried out, the relevant plant / equipment described poses no problems in relation to retrofit or conversion.

6.6 Flue Gas Treatment

For the CCGT Power Plant with Post-Combustion CO2 Capture, the provision of space for stand-alone direct contact flue gas coolers will allow for the removal of any SOx that may be present in the flue gases at the time of installing the CO2 capture plant. Selective Catalytic Reduction (SCR) is not deemed to be required for the CO2 capture process assumed in this Feasibility Study as the LCPD / IED Limits for NOx will result in flue gas containing a quantity of NO2 that will not impact on the CO2 capture process.

6.7 Cooling System

For operation as an IGCC power plant or addition of post combustion CO2 capture on a CCGT, hybrid cooling towers would be used in the same way as under operation as a CCGT power plant.

As noted in Section 4, the spent steam leaving the steam turbine would pass through a condenser and be returned to the HRSG. The heat rejected by the steam in the condenser would be passed to (and thus heat) the cold cooling water. The heated cooling water leaving the condenser would be passed through the hybrid cooling towers where the heat would be rejected to atmosphere. The cold cooling water exiting the hybrid cooling towers would be returned to the condenser. Accordingly, the cooling system would operate by continuously circulating the cooling water between the condenser and the hybrid cooling tower arrangement.

Hybrid cooling towers are composed of a dry section and a wet section. In hybrid cooling towers, typically the heated cooling water is passed to the top of the hybrid cooling towers and flows through an air cooled heat exchanger that performs approximately 20 per cent of the cooling duty, depending upon ambient conditions. The cooling water then leaves the air cooled heat exchangers and is sprayed down the wet section of the hybrid cooling towers where the remaining heat is lost through evaporation. The continuous circulation of the cooled water results in the concentrating of the dissolved solids present, and this could impact on the operating efficiency of the condenser and hybrid cooling towers through the fouling / scaling of the heat transfer interfaces. Therefore, in order to maintain the correct operation and control of the cooling system, it is necessary to continuously purge and replace the cooling water.

IGCC Power Plant with Pre-Combustion CO2 Capture

Assuming the conversion of a CCGT power plant to an IGCC power plant with CO2 capture, the load on the cooling system would increase from approximately 250 MJ/s to 420 MJ/s. The associated increase in make-up water for the cooling system will be approximately 1500 to 2000 tonnes/hour, depending upon ambient conditions. It is assumed that cell type hybrid cooling towers would be used. Sufficient cells for operation as a CCGT power plant would be installed initially, with space allocated for future expansion such that the cooling system is sized to allow for operation as an IGCC power plant with CO2 capture.

Accordingly, the necessary expansion of the cooling system for operation as an IGCC power plant is already anticipated. Therefore, subject to detailed design being carried out, the expansion of the cooling system poses no problems in relation to retrofit or conversion.

CCGT Power Plant with Post-Combustion CO2 Capture

Introduction of a CO2 capture plant requires additional cooling for:

- Cooling of the flue gases to the required absorber inlet temperature (flue gas cooling);
- Cooling of the lean amine before entry to the absorber column (process cooling);
- Inter-cooling of the CO2 compressors;
- Cooling of CO2 capture plant ancillary equipment (plant cooling); and,
- Cooling of the condensate from the CO2 stripping process.

Similar to conversion to IGCC, it is assumed additional cells would be added to manage the additional cooling load.

Piping would be appropriately sized to allow expansion of the cooling water system but ensure a minimum velocity and flow is maintained. Additional pumps can be added if required to handle the increased flow

Therefore, based on the above, the relevant plant and equipment poses no problem in relation to retrofit and integration (subject to detailed design being carried out).

6.8 Compressed Air System

IGCC Power Plant with Pre-Combustion CO2 Capture

The compressed air system would likely comprise two 100 per cent streams, comprising: packaged-type air compressor units; filters / dryers; an air receiver; and, an air distribution main (to supply the air consumers within the IGCC power plant).

As with other elements, subject to detailed design being carried out, the relevant plant / equipment described poses no problems in relation to retrofit or conversion.

CCGT Power Plant with Post Combustion CO2 Capture

Process compressed air will not be required but a small amount of service air and instrument air will be required for maintenance requirements and supply to the CO2 capture plants instruments.

As only a small amount of compressed air is required, it is envisaged an air compressor system (air compressors, air dryers and air receivers) will be installed on the CO2 capture plant in the utilities area.

In terms of sizing in the plot plan layouts, we have assumed 2 compressed air streams for the plant. Each stream consists of an air compressor (with a free air delivery of 500m3/hr at 8 bar), an air dryer and an air receiver (2,000 litre). Intermittent uses from other known projects has been the basis for sizing. Each stream has an approximate 3m x 5m footprint. Space provision for the compressed air streams have been included in the Utilities and Balance of Plant Area.

6.9 Raw Water Pre-Treatment

Based on the conversion of a CCGT power plant to an IGCC power plant:

During operation on syngas, make-up water requirements would increase due to the requirements of the gasification plant; and.

During operation on natural gas (in IGCC power plant mode), make-up water requirements would increase due to the requirements for make-up water for the steam cycle (as steam, extracted from the steam cycle, is used as a diluents for the non-DLN diffusion combustors).

This element is marked (8) in Figure 3 and would be capable of being accommodated. Therefore, subject to detailed design being carried out, the relevant plant / equipment described poses no problems in relation to retrofit or conversion.

Minimal additional raw water is required for the post-combustion carbon capture plant. Majority of process water required is demineralised water. The raw water tank on the CCGT Plant will be sized for small additional amount required on the CO2 capture plant.

6.10 Demineralisation / Desalination Plant

IGCC Power Plant with Pre-Combustion CO_2 Capture

Based on the conversion of a CCGT power plant to an IGCC power plant, the largest water demand would be during operation on natural gas (in IGCC power plant mode) where make-up water requirements would increase due to the requirements for make-up water for the steam cycle (as steam, extracted from the steam cycle, is used as a diluents for the non-DLN diffusion combustors).

This element is marked (8) in Figure 3 and would be capable of being accommodated. Therefore, subject to detailed design being carried out, the relevant plant / equipment described poses no problems in relation to retrofit or conversion.

CCGT Power Plant with Post-Combustion CO_2 Capture

Due to the absorber column design operating temperature selected, the CO_2 capture plant is a net producer of water and no evaporative losses will be realised from the flue gas.

However, additional demineralised water will be required to replace the water removed during the amine reclaiming process. At present this is estimated to be approximately 0.26 kg/s.

The requirements for the demineralised water plant / equipment to accommodate the CO_2 capture plant would be finalised during detailed design.

6.11 Waste Water Treatment Plant

IGCC Power Plant with Pre-Combustion CO_2 Capture

For operation as an IGCC power plant with CO_2 capture, waste water is likely to comprise that from the gasifier (marked (14) in Figure 3), syngas cooling section and blowdown from the acid gas and CO_2 removal unit (marked (16) in Figure 3).

The Waste Water Treatment Plant will treat this waste water to control the concentrations of various compounds to within the limits prescribed by the Environmental Permit. The resulting effluent will likely be discharged to the River Humber, via the blow down from the hybrid cooling towers.

The required layout and capacity of the Waste Water Treatment Plant would be clearly defined during the detailed design stage. This element is marked (19) in Figure 3, and would be capable of being accommodated. Therefore, subject to detailed design being carried out, the relevant plant / equipment described poses no problems in relation to retrofit or conversion.

The detailed design will include provisions for surface water drainage, contaminated surface water drainage (which would initially drain to oil interceptors) and process water drainage.

CCGT Power Plant with Post-Combustion CO_2 Capture

The process waste water discharge for the CO_2 capture plant has been estimated to be 8.05 kg/s.

It is proposed the process waste water discharge from the CO_2 capture plant can be sent to a flue gas desulphurisation waste water treatment plant. It has been confirmed that there is sufficient capacity in the waste water treatment plant to accept the maximum discharge flow from the CO_2 capture plant.

The final design of the CO_2 capture plant will have provisions to include for surface water drainage. Any contaminated surface water drainage will pass through an oil interceptor before discharge into the main plant drainage system which would drain to oil interceptors.

The relevant plant and equipment poses no problem in relation to retrofit and integration (subject to detailed design being carried out).

The generation of effluents from the carbon capture process are discussed in section 10 (Requirement for a Hazardous Substances Consent (HSC)).

6.12 Electrical

The gas turbine and steam turbine generators, and step-up transformers, will be sized for the maximum generator output. Accordingly, the outgoing high voltage (HV) electrical connection to the National Grid National Electricity Transmission System (and associated systems) will also be designed for the maximum electrical power output.

The gas turbine and steam turbine generator outputs, and the associated electrical power outputs, are shown in Table 6.1 for the generating station operating as an IGCC power plant with CO_2 capture and CCGT power plant with CO_2 capture.

For the purposes of comparison, Table 6.1 also shows the gas turbine and steam turbine generator outputs, and the associated electrical power outputs, of the generating station operating as:

a) A CCGT power plant fired on natural gas, with DLN combustors (i.e. prior to conversion to an IGCC power plant);

b) A CCGT power plant fired on natural gas, with diffusion combustors;

c) An IGCC power plant fired on coal without CO_2 capture, with diffusion combustors; and,

d) An IGCC power plant fired on biomass (torrefied biomass) without CO_2 capture, with diffusion combustors.

e) A CCGT power plant fired on Natural Gas with CO_2 Capture (GE 9F.05)

Table 6.1 - Gas Turbine and Steam Turbine Generator Electrical Power Outputs, and the Associated Net Electrical Power Output

	IGCC Power Plant (fired on Coal) with CO_2 Capture	***CCGT Power Plant fired on Natural Gas with DLN Combustors***	***CCGT Power Plant fired on Natural Gas with Diffusion Combustors***	***IGCC Power Plant (fired on Coal) without CO_2 Capture***	***IGCC Power Plant (fired on Biomass (Torrefied Biomass)) without CO_2 Capture***	***CCGT Power Plant fired on Natural Gas with CO_2 Capture (GE 9F.05)***
Gas Turbine Generator	343	329	343	332	334	325
Steam Turbine Generator	172	150	128	154	156	146
Total Generator	515	479	471	486	490	467
Auxiliary Consumption	97	12	12	53	45	39
Net Output	418	467	459	433	445	428

Table 6.1 demonstrates that although the steam turbine generator output is greater during operation as an IGCC power plant, net electrical power output available for export is greater when operating as a CCGT power plant. This is due to the larger auxiliary power consumption when operating as an IGCC power plant.

The gas turbine generator has its own dedicated medium voltage (MV) unit switch board, and low voltage (LV) unit auxiliary switchboard to provide power to the respective turbine generator auxiliaries. As operation of the IGCC power plant has a larger auxiliary power consumption than operation of the CCGT power plant, it is likely that the electrical distribution system for the IGCC power plant will be from a dedicated electrical distribution system via step-down transformers from the main HV switchboard.

Accordingly, the changes or initial specification associated with conversion to an IGCC power plant / construction of an IGCC power plant at the outset have already been taken into account. Accordingly, subject to detailed design being carried out, the relevant plant / equipment described poses no problems in relation to retrofit or conversion.

The CCGT post-combustion plant has much lower generator output when compared to IGCC pre-combustion plant. It also requires less auxiliary load to operate the post combustion plant resulting in a higher net output. In terms of retrofitting from a CCGT plant, it is proposed the auxiliaries required for the capture plant is taken from a new, dedicated electrical distribution system via step-down transformers from the main HV switchboard.

6.13 Nitrogen System

For operation as an IGCC power plant, nitrogen would be produced by an ASU (marked (20) in Figure 3). Nitrogen would be used primarily for syngas dilution (before syngas passes to the gas turbine) and emissions control (as a diluent in the non-DLN diffusion combustors). Some nitrogen may also be sent to the gasifier for fuel transport. Nitrogen may be stored on the Application Site (marked (21) in Figure 3).

This element is needed only in for operation as an IGCC power plant. This element (comprising the ASU and nitrogen storage tanks) is marked (20) and (21) in Figure 3, and would be capable of being accommodated. Therefore, subject to detailed design being carried out, the relevant plant / equipment described poses no problems in relation to retrofit or conversion.

6.14 Chemical Dosing System

The significant chemical dosing systems anticipated during operation as an IGCC power plant with CO_2 capture are associated with the following processes:

a) Gasifier Waste Water Treatment Plant;

b) Boiler Feedwater Conditioning

c) Site Waste Water Treatment Plant; and,

d) Cooling Water Conditioning.

These parts of the Project are capable of being included in the Operations Area. Therefore, subject to detailed design being carried out, there is no technical or physical reason why they would pose a problem in relation to retrofit or conversion.

6.15 Waste Separation and Disposal

The significant solid wastes anticipated during operation as an IGCC power plant with CO_2 capture are:

a) Ash (in the form of inert slag and fly ash from the gasifier (marked (14) in Figure 3));

b) Filter cake (from the Waste Water Treatment Plant (marked (19) in Figure 3)); and,

c) Sulphur (extracted in elementary form from the acid gas and CO_2 removal unit (marked (16) in Figure 3)).

It is anticipated that:

a) The ash from the gasifier (the inert slag and fly ash) will be sold for use in the construction industry or transported to an appropriate landfill site by a suitably licensed contractor;

b) The filter cake from the Waste Water Treatment Plant will be stored in dedicated waste containers that will be suitable for loading directly on to the back of heavy haulage vehicles; and,

c) The sulphur (extracted in elementary form from the acid gas and CO_2 removal unit) will be sold as a raw material for use in the chemical industry.

The requirements for the waste separation and disposal system and necessary infrastructure would be clearly defined during detailed design. However, subject to detailed design being carried out, there is no technical or physical reason why they would pose a problem in relation to retrofit or conversion.

6.16 Plant Pipe Racks

The layout and sizing of the plant pipe racks allow for the pipe work (including those for the interfaces described in Section 6.18 (Interfaces)) between the generating station and the gasification plant.

Accordingly, these parts of the Project are capable of being included in the Operations Area. Therefore, subject to detailed design being carried out, there is no technical or physical reason why they would pose a problem in relation to retrofit or conversion.

6.17 Control and Instrumentation

The provision of space for control and monitoring instrumentation would include for the routing of cabling to and the installation of all control and monitoring instrumentation within the control room (within the Administration Building).

The Administration Building is marked (11) in Figure 3.

The required space for additional control and monitoring instrumentation to accommodate control during operation of an IGCC power plant or CCGT power plant would be carried out during detailed design. However, as the Administration Building is accommodated, subject to detailed design being carried out, the relevant plant / equipment described poses no problems in relation to retrofit or conversion.

6.18 Plant Infrastructure

The provision of space for the plant infrastructure (gasification plant and common facilities) for construction / operation as an IGCC power plant with CO2 capture can be seen in Figure 3 and for construction / operation as a CCGT power plant with post-combustion CO2 capture can be seen in Figure 10?? plus interfaces for: syngas; cooling water; service air; effluent discharge; electrical; control and instrumentation; potable water; and firefighting.

6.19 Interfaces

For operation as a CCGT power plant with CO2 capture, interfaces include those identified in Table 4.10 plus interfaces for flue gas, cooling water, demineralised water, effluent discharge, electrical, control and instrumentation, potable water and firefighting.

During the detailed design of the Project, terminal point for each interface, including (where appropriate): pipe size; fluid type; flow; temperature; and, pressure would be identified. Accordingly, any required interfaces would be clearly defined.

Subject to detailed design being carried out, there is no technical or physical reason why they would pose a problem in relation to retrofit or conversion.

6.20 CCR Status and Full Development of CCS

This Section demonstrates that, subject to detailed design being carried out, there is no technical or physical reason why construction or conversion of an IGCC power plant with pre-combustion CO2 capture or a CCGT power plant with post-combustion CO2 capture could not be achieved.

As required by the CCR Guidance, this 'Technical Assessment – Retrofitting and Integration of CCS Technology' will be reviewed on an ongoing basis as part of the Status Report to be submitted every 2 years (from the first date of commercial operation of the CCGT power plant until construction / conversion to CO2 capture), with a view to incorporating any developments into an updated design.

7 TECHNICAL ASSESSMENT - CO2 STORAGE AREAS

Alongside the information provided in the 2013 Submission, this section has been updated to include the CO2 Storage Area requirements associated with a CCGT Power Plant with Post-Combustion CO2 Capture technology. The thermodynamic model created of the CCGT Power Plant with Post-Combustion CO2 Capture technology has be used as an input to provide updated information. The updated information is comparative in detail to the information provided in the 2013 Submission.

7.1 Potential CO2 Storage Areas

In order to identify potential CO2 storage areas, it is necessary to understand the CO2 storage requirements for the IGCC power plant with pre-combustion CO2 capture and the CCGT power plant with post-combustion CO2 capture. In line with the calculations detailed in Table 4.2, the CO2 storage requirement for the IGCC power plant with pre-combustion CO2 capture is approximately 78.4 million tonnes of CO2. In line with the calculations detailed in Table 4.3, the CO2 storage requirement for the CCGT power plant with post-combustion CO2 capture is approximately 33.7 million tonnes of CO2.

Based on the DTI Study 2006[18] (provided in Annex D of the CCR Guidance), the Galleon gas field and Ravenspurn (North and South) gas fields in the South North Sea (SNS) Basin are potential CO2 storage areas which meet the CO2 storage requirement for the IGCC power plant with pre-combustion CO2 capture and the CCGT power plant with post-combustion CO2 capture. The location of these CO2 storage areas is illustrated in Figure 6.

In updating the 2013 Submission, the storage requirements of the CO2 capture technologies were reassessed against updated documentation. It has been assumed since the CCR Guidance is still valid and used in this submission, that therefore the DTI Study 200614 (provided in Annex D of the CCR Guidance) is also still valid and can be used to provide the CO2 storage requirements for the updated submission.

It is recognised that in the future there may be competing interest for the identified CO2 storage sites, as other carbon capture and storage projects become operational. It is also recognised that other CCR applications may also have identified the same geological fields for CO2 storage capacity. However, according to the BEIS Website (formerly DECC), (https://itportal.beis.gov.uk/EIP/pages/c02.htm), only North Killingholme has been identified for the Galleon gas field and Knottingley CCGT has been identified for Ravenspurn gas field with enough capacity left over for the requirements detailed below. CO2 Storage Area Capacity and CO2 Storage requirement.

The Galleon gas field has a capacity of 137 million tonnes of CO2 and the Ravenspurn (North and South) gas field has a total capacity of 145 million tonnes of CO2.

Accordingly, Table 7.1 illustrates the percentage CO2 storage requirements on these two gas fields.

[18] *DTI, "Industrial Carbon Dioxide Emissions and Carbon Dioxide Storage Potential in the UK", Report No. COAL R308, URN6/2027, October 2006.*

Table 7.1 - Percentage CO2 Storage Requirements

	CO_2 Storage Requirement 78.4 Million tonnes CO2	
	IGCC with Pre-Combustion CO2 Capture	**CCGT with Post-Combustion CO2 Capture**
Galleon Gas Field 137 Mt CO_2	57%	25%
Ravenspurn (North and South) Gas Fields 145 Mt CO_2	54%	23%

In the future it is likely there may be competing interest for these identified CO2 storage areas as other CCS projects become operational. However, there are a large number of additional CO2 storage areas which exist in the same region that are capable of meeting the CO2 storage requirements.

Table 7.2 presents a summary of the total CO2 storage capacity[19] of the additional CO2 storage areas which exist in the same region.

Table 7.2 - Total CO2 Storage Capacity for IGCC Power Plant with Pre-Combustion CO2 Capture and CCGT Power Plant with Post-Combustion CO2 Capture

	Total CO_2 Storage Requirement / Capacity (Million tonnes)	
	IGCC with Pre-Combustion CO2 Capture	**CCGT with Post-Combustion CO2 Capture**
CO_2 Storage Requirement	78.4	33.7
Total CO_2 Storage Capacity	3,310	3,310
Percentage CO_2 Storage Requirement against CO_2 Storage Capacity	2.4%	1.0%

Whilst the decision as to which specific CO2 storage area to use (for any project) will not be made until implementation of CO2 transportation and storage, Table 7.2 shows that the potential CO2 storage areas in the same region have a CO2 storage capacity of approximately 3,310 million tonnes of CO2. The Project operating as an IGCC power plant with CO2 capture would require approximately 2 per cent of this CO2 storage capacity over its 30 year lifetime. The project operating as a CCGT with post-combustion CO2 capture would require 0.9% of this CO2 storage capacity over its 30 year lifetime.

Another possibility is that there will be an available “CO2 Network” in the region such that CO2 from the Project (operating as an IGCC power plant with CO2 capture or a CCGT power plant with post-combustion CO2 capture), and other power plants in the region,

[19] *ETI, D05: WP4 Report Appendix 5 – Site Assessments 10113ETIS-Rep-08-1.1 August 2015*

would be delivered to a central hub. From this central hub, the captured CO2 would likely be delivered to a number of CO2 storage areas.

7.2 CCR Status and Full Development of CCS

In terms of the availability of CO_2 storage areas it is plain that sufficient capacity is available subject to securing CO_2 transportation and storage consents and delivery of necessary infrastructure.

As required by the CCR Guidance and as stated in Clause 35 of the Order, this 'Technical Assessment – CO_2 Storage Areas' will be reviewed on an ongoing basis as part of a monitoring report to be submitted every 2 years (from the first date of commercial operation of the CCGT power plant until construction / conversion to CO_2 capture), with a view to incorporating any developments into an updated design.

8 TECHNICAL ASSESSMENT - CO2 TRANSPORT

8.1 ROUTE VERIFICATION

The routes proposed in the 2013 Submission for the onshore and offshore transportation of CO2 have been verified to still be valid. This validation was provided through gas pipeline maps obtained from the National Grid Gas website. There have been no recent developments to suggest that the offshore routing would change since the 2013 Submission.

8.2 Consideration at the Applications Site

The exit point for the CO_2 pipeline from the Operations Area has been placed to match the most likely on shore CO_2 pipeline route corridor and is shown on Figure 3.

8.3 CO2 Transport Onshore

It is proposed that CO_2 transport on shore, from the Application Site to the coastal transition point, is via an on shore CO_2 pipeline.

The proposed on shore CO_2 pipeline route corridors are shown on Figure 7 which illustrate a 1 km wide corridor for the first 10 km of the CO_2 pipeline route corridor and a 10 km wide route corridor thereafter. With a view to minimising any potential environmental / health / safety impacts, it has been considered desirable to follow the route of existing (National Grid) National Gas Transmission System pipeline routes wherever possible.

Accordingly, the on shore CO_2 pipeline route corridor would run from the Operations Area to link in with the National Gas Transmission System pipeline routes. In identifying the CO_2 pipeline route corridor from the Operations Area to the National Gas Transmission System, the same principles have been applied that were used to identify the gas connection route corridors. C.GEN considers that it is possible to identify a route to this point.

From the National Gas Transmission System, the on shore CO_2 pipeline route corridor would either run to the north (Easington Option) or to the south (Theddlethorpe Option).

Easington Option

The proposed coastal transition point would be the Easington Gas Terminal on the north bank of the River Humber.

Upon joining the route of the National Gas Transmission System, the CO_2 pipeline route corridor would turn northwards. Upon reaching the south bank of the River Humber, the CO_2 pipeline route corridor would cross under the River Humber (either through existing pipeline tunnels or through a new tunnel) before landing on the north bank of the River Humber, to the east of Kingston upon Hull. The on shore CO_2 pipeline route corridor would then run south east to the proposed coastal transition point at the Easington Gas Terminal.

The CO_2 pipeline route corridor length is approximately 35 km.

Theddlethorpe Option

The proposed coastal transition point would be the Theddlethorpe Gas Terminal on the Lincolnshire Coast.

Upon joining the route of the National Gas Transmission System, the CO_2 pipeline route corridor would turn southwards. To the east of Lincoln, the CO_2 pipeline would turn to run east to the proposed coastal transition point at the Theddlethorpe Gas Terminal.

The CO_2 pipeline length is approximately 85 km.

8.4 CO2 Transport Offshore

It is proposed that CO_2 transport off shore, from the coastal transition point to the CO_2 storage area, is via an off shore CO_2 pipeline. The proposed off shore CO_2 pipeline route corridors are shown on Figure 6.

Again, with a view to minimising any potential environmental / health / safety impacts, it has been considered desirable to follow the route of existing pipeline routes wherever possible.

8.5 CO2 Transport Barriers –

On shore

In terms of these on shore barriers, the on shore CO_2 pipeline route corridor has followed the route of existing National Gas Transmission System pipeline routes (wherever feasible). In doing so it is considered that the on shore CO_2 pipeline route corridor has been designed in line with the following guiding principles:

a) Routed away from habitation (and any potential future developments) as much as possible to reduce the impacts of construction and operation;

b) Routed close to existing hydrocarbon pipelines to minimise proliferation of pipelines; and,

c) Route close to existing hydrocarbon pipelines to minimise the number of different landowners / tenants affected.

Accordingly, it is considered that there are no known barriers or unavoidable safety obstacles which exist within the identified on shore CO_2 pipeline route corridor.

However, it may be that the on shore CO_2 pipeline would likely to run through or near to areas with environmental constraints. Typically, these include: Special Protection Areas (SPAs); Special Areas of Conservation (SACs); Sites of Special Scientific Interest (SSSI); Natura 2000 site; Sensitive Marine Areas (SMAs); and, RAMSAR sites (especially around coastal areas).

If, after further CO_2 pipeline routing studies, it is not possible to avoid these areas, trenchless construction techniques (i.e. auger boring / Horizontal Directional Drilling (HDD)) would be used to minimise any environmental impacts and meet any relevant regulations. Furthermore, the impact on protected habitats and species may be minimised by planning the construction of the CO_2 pipeline around breeding seasons and migrating patterns.

Off shore

In terms of these off shore barriers, the off shore CO_2 pipeline route corridor has followed the route of existing pipeline routes (wherever possible). In doing so it is considered that the off shore CO_2 pipeline route corridor has been designed in line with the above guiding principles.

Accordingly, it is considered that there are no known barriers or unavoidable safety obstacles which exist within the identified off shore CO_2 pipeline route corridor.

However, it may be that the off shore CO_2 pipeline would likely to run through or near to areas with environmental constraints. Typically these include: passing through environmentally sensitive wetlands; off shore wind farm sites and associated cabling; dredging areas; existing pipeline infrastructures; disposal sites; and, shipping lanes.

In terms of environmentally sensitive wetlands, and to minimise any environmental impacts at points close to shore, specialist trenching and laying construction techniques would be used at low tide or low current periods. Where any environmental impacts are deemed to be unacceptable, trenchless construction techniques may be used. Furthermore, the impact on protected habitats and species may be minimised by planning the construction of the CO_2 pipeline around breeding seasons and migrating patterns.

In terms of off shore wind farm sites and associated cabling, dredging areas, existing pipeline infrastructures and disposal sites, navigation is considered feasible. Indeed, it is currently considered that there is sufficient space between such sites to allow for the installation of an off shore CO_2 pipeline within the specified CO_2 pipeline route corridor.

In terms of shipping lanes, it is not anticipated that these lanes would be a significant barrier to an off shore CO_2 pipeline as the off shore CO_2 pipeline would run along the seabed at a sufficient depth to allow ships to pass freely above. In addition, the relevant knowledge, skills, experience and techniques that exist in the UK Natural Gas and Oil Industries for this to be a feasible option.

Further, whilst not discussed in detail in this Document, shipping of CO_2 to remote CO_2 storage areas may also be considered in the future. However, since there are a wider range of uncertainties surrounding this option (such as temporary on shore storage, consenting requirements and land use issues) it is not considered further. As the uncertainties surrounding this option decrease, this option may be considered in the future as a viable transport option, and therefore will be reviewed.

8.6 CO2 Transport Networks

The use of CO_2 transport networks will also be considered in the future, where they are available.

Indeed, based on information in Yorkshire and Humber Carbon Capture, Transportation and Storage – Strategic Options Appraisal Report (National Grid, June 2011), National Grid considers that:

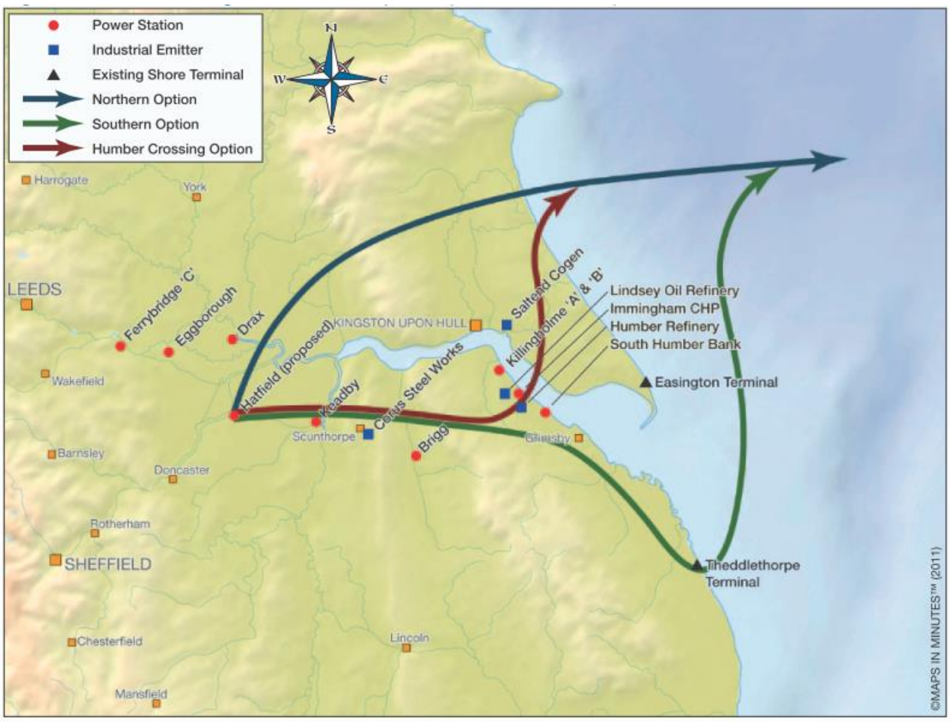
a) (At paragraph 3.3.3) there is a "*desire to develop a CO_2 transportation and storage network which will satisfy both short and longer term demands within the* [Yorkshire and Humber] *region*";

b) (At paragraph 3.4.2) there are "*a number of strategic options that could potentially be considered as technically feasible methods to transport CO_2 from point source emitters in the Yorkshire and Humber region to a storage site under the North Sea*", but that (at paragraph 5.5.1) "*buried pipelines on shore and laying a pipeline on the seabed* [off shore] *have been identified as the most suitable and only practical means of transporting CO_2 from the point source emitters in the Yorkshire and Humber region to the storage sites in the North Sea*"; and,

c) (At paragraph 6.2.7) "*three broad strategic connection options have been established. ... Each of these options would have potential to form part of an extended CCS* *network if, during the demonstration phase, the complete CCS chain has been demonstrated at commercial scale on the power station*".

The three broad strategic connection options are described as the Northern Option, the Southern Option and the Humber Crossing Option. These are shown on Insert 8.1.

Insert 8-1 - NATIONAL GRID BROAD STRATEGIC CONNECTION OPTIONS
[20]



From Insert 8.1 it can be seen that the National Grid 'Humber Crossing Option' and 'Southern Option' are similar to the Easington Option and Theddlethorpe Option respectively. However, it is stated in the CCR Guidance (at paragraph 51) that "*applicants may not, when applying for an initial ...* [DCO] *assume ... that they will be able to outsource such onshore transport arrangements at the time of future CCS deployment*". This is considered prudent since National Grid has chosen for the time being to promote the Northern Option.

Therefore, whilst not discussed in detail in this Document, the use of CO_2 transport networks may also be considered in the future. Accordingly, as the uncertainties surrounding the use of CO_2 transport networks decrease, this option may be considered in the future as a viable transport option, and therefore will be reviewed.

[20] *Taken from http://files.opendebate.co.uk/files/nationalgrid/ccshumber/Strategic%20Options%20Appraisal%20Report%20Figures.pdf*

8.7 CO2 Transport Considerations

Factors Influencing Pipeline Route Selection

Ultimately, it is unlikely that the shortest CO_2 pipeline route from the Application Site to the identified CO_2 storage area will be the most suitable, and indeed the design of any CO_2 pipeline (or CO_2 pipeline network) will take a number of factors into consideration. These factors will include:

a) Safety (both public and personnel);

b) Pipeline fluid and proposed operating conditions;

c) Environmental impact (including designated areas);

d) Geological conditions (including topographical, geotechnical and hydrographical conditions);

e) Land use (both existing and future);

f) Third party activities;

g) Agricultural practice;

h) Existing facilities and services (including transport and utilities);

i) Access;

j) Construction, testing, operation and maintenance;

k) Security; and

l) Any other hazards.

Therefore, in order to further develop the CO_2 pipeline route from the Application Site to the identified CO_2 storage area, it is likely that three phases of routing would be adopted. The phases of routing would be:

Phase 1) CO_2 pipeline route corridor selection.

Phase 2) CO_2 pipeline route corridor investigation and consultation.

Phase 3) Design and approval of the final CO_2 pipeline route.

Safety Considerations

As noted in the CCR Guidance, it may be that dense phase CO_2 would be present on-site and within the CO_2 pipeline once the captured CO_2 is compressed in preparation for transport. Whilst dense phase CO_2 is not currently classified as hazardous, it is now recognised that an accidental release of large quantities of CO_2 could result in a major accident. As such, there is currently extensive ongoing research into the hazard potential of dense phase CO_2. The results of this ongoing research will inform future decisions on CO_2 and whether a classification review (i.e. so that dense phase CO_2 is classified as hazardous) is necessary.

As a result, in terms of CO_2 pipeline routes / transport, the mechanisms, hazards, consequences and probabilities of CO_2 pipeline failure need to be understood so that safe design, commissioning and operation can be ensured. Accordingly, a precautionary approach has been taken in respect of dense phase CO_2 to ensure no foreseeable barriers exist along the proposed CO_2 pipeline route.

In line with the precautionary approach, the Health and Safety Executive (HSE) require that dense phase CO_2 is treated as a "*dangerous fluid*" under the Pipeline Safety Regulations 1996.

In addition, a dense phase CO_2 pipeline would be treated as a "Major Accident Hazard Pipeline" under the Pipeline Safety Regulations 1996. As such, the following documents / considerations would need to be produced / included for the ultimate design, commissioning and operation of a dense phase CO_2 pipeline:

a) A 'Major Accident Prevention Plan;

b) A 'Pipeline Safety Evaluation and Technical Safety Risk Assessment', including failure mechanisms, probability and consequence of failure. Mitigation measures will also be detailed;

c) An 'Asphyxiation Risk Assessment';

d) An 'Operations, Maintenance and Emergency Response Policy', including procedures and work instructions for:

   i. The safe control of operations; and,

   ii. The safe working in the vicinity of a high pressure pipeline.

e) Emergency shutdown valves to be fitted to the CO_2 pipeline; and

f) The relevant Local Authority to be notified and this Local Authority to have prepared an 'Emergency Plan'.

However, it is not yet necessary to address these items at this stage due to the uncertainty surrounding the final CO_2 pipeline route and the classification of dense phase CO_2. In this regard, C.GEN will hold informal discussions with the Local Planning Authority (LPA) about the potential issues surrounding dense phase CO_2, including the implications behind transport via a dense phase CO_2 pipeline. These informal discussions will continue until further information concerning the classification of dense phase CO_2 is available. This will ensure that there is early identification of any potential implications on the LPA's long term plan for the area. However, at this stage is it felt that no formal discussions or preparations are necessary.

8.8 CCR Status and Full Development of CCS

As required by the CCR Guidance, this 'Technical Assessment – CO_2 Transport' will be reviewed on an ongoing basis as part of the Status Report to be submitted every 2 years (from the first date of commercial operation of the CCGT power plant until construction / conversion to CO_2 capture), with a view to incorporating any developments into an updated design.

9 ECONOMICAL ASSESSMENT

The intention of the economical assessment carried out in the 2013 Submission was to determine what CO2 carbon tax (£/tonne) would be required to make it economically favourable for conversion of a CCGT power plant to an IGCC power plant with CO2 capture.

For the updated report, a second scenario is being looked at – Determining what CO2 carbon tax (£/tonne) would be required to make it economically favourable to retrofit a natural gas fired CCGT Plant with post-combustion carbon capture technology.

As the construction and operational assumptions for the two scenarios are different, it is not possible to recreate the same economical assessment and make a fair comparison between the two. It has therefore been deemed appropriate to include a standalone economical assessment section within the report for the new post-combustion carbon capture technology scenario.

Section 9 has therefore been split into two sub sections:

Section 9A – Economical Assessment - Convert to IGCC with pre-combustion carbon capture

Section 9B – Economical Assessment – Retrofitting a CCGT with post-combustion carbon capture

As the economics of conversion of a CCGT power plant to an IGCC power plant with CO2 capture is not being amended as part of the update to the Order and there is no intention to compare the two scenarios against each other, no update has been made to the assumptions in Section 9A.

The new Section 9B economical assessment has been based on 2020 costs rather than 2013 costs. This has the advantage of bringing the economical assessment up to date and simplifies subsequent economical reviews as part of the CCR Status Report (to be submitted every two years following CCGT plant commissioning).

9A ECONOMICAL ASSESSMENT – CONVERT TO IGCC WITH PRE-COMBUSTION CARBON CAPTURE

9.1 Introduction

This Section presents the results of the economical assessment for conversion of a CCGT power plant to an IGCC power plant with CO2 capture. For purposes of confidentiality, the economical assessment is based on generic, modelled and / or quoted cost information.

9.2 Economical Assessment Inputs

Generic New-build CCGT Power Plant

The model inputs for the generic new-build CCGT power plant can be summarised as:

a) Estimate of Capital Expenditure (CAPEX) is £575/kW (central estimate based on Next of a Kind (NOAK) project);

b) Estimate of Operation and Maintenance (OPEX) costs is £18,876/MW per year (central estimate based on NOAK project);

c) Efficiency of 58.8% (based on new-build (high efficiency) CCGT power plant); and,

d) Degradation and outages based on new-build CCGT power plant.

CCGT Power Plant (Before conversion to an IGCC Power Plant)

a) The model inputs for the CCGT power plant can be summarised as:

b) Estimate of CAPEX is £546/kW (based on an assumed 5% decrease compared to generic new-build CCGT power plant);

c) Estimate of OPEX costs is £18,876/MW per year (central estimate based on NOAK project);

d) Efficiency is based on modelled information; and,

e) Degradation and outages based on generic new-build CCGT power plant.

New-build IGCC Power Plant with CO_2 Capture

The model inputs for the IGCC power plant with CO2 capture can be summarised as:

a) Estimate of CAPEX is £3,010/kW (central estimate based on First of a Kind (FOAK) project);

b) Estimate of OPEX costs is £75,408/MW per year (central estimate based on FOAK project);

c) Transport and Storage costs are £15/MWh (based on €20/tonne of CO2 recalculated on a per MWh basis using a typical carbon content of coal and proposed efficiency);

d) Efficiency is based on modelled information; and,

e) Degradation and outages based on generic new-build CCGT power plant.

Conversion to an IGCC Power Plant with CO_2 Capture

The model inputs for the conversion to an IGCC power plant with CO2 capture can be summarised as:

a) Estimate of CAPEX is £2,464/kW (based on IGCC power plant with CO2 capture minus the CAPEX for the CCGT power plant);

b) Estimate of OPEX costs is £75,408/MW per year (central estimate based on FOAK project);

c) Transport and Storage costs are £15/MWh (based on €20/tonne of CO2 recalculated on a per MWh basis using a typical carbon content of coal and proposed efficiency);

d) Efficiency is based on modelled information; and,

e) Degradation and outages based on generic new-build CCGT power plant.

Summary

A summary of the above economical assessment model inputs is provided in Table 9.1.

Table 9.1 - Summary of the Economical Assessment Model Inputs

Scenario Name	***Units***	***Generic New-build CCGT Power Plant***	***CCGT Power Plant***	***New Build IGCC Power Plant with CO_2 Capture (with Transport and Storage)***	***Conversion to an IGCC Power Plant with CO_2 Capture (with Transport and Storage)***
General					
Primary Fuel Used		Gas	Gas	Coal	Coal
Construction Start Year		2013	2013	2013	2013
Performance					
Net Power Output	MW	900	470	470	470
Capacity Utilisation	%	50	50	100	100
Heat Rate LHV	kJ/kWh	6122	6545	9730	9730
Capture Efficiency	%	0	0	88	88
Economic Life Expectancy	Years	30	30	30	30
Annual Power Degradation between Major Outages	% p.a.	0.50	0.50	0.50	0.50
Unrecovered Power Degradation at Major Outages	%	0.40	0.40	0.40	0.40
Annual Heat Rate Degradation between Major Outages	% p.a.	0.25	0.25	0.25	0.25
Unrecovered Heat Rate Degradation at Major Outages	%	0.25	0.25	0.25	0.25

Scenario Name	*Units*	*Generic New-build CCGT Power Plant*	*CCGT Power Plant*	*New Build IGCC Power Plant with CO_2 Capture (with Transport and Storage)*	*Conversion to an IGCC Power Plant with CO_2 Capture (with Transport and Storage)*
Outages					
Major Planned Maintenance	Days	30	42	42	42
Minor Planned Maintenance	Days	14	14	14	14
Interval between Major Outages	Years	6	4	4	4
Forced Outage Rate	%	6.00	6.00	6.00	6.00
First Year Availability Reduction	%	25.00	25.00	25.00	25.00
Capital Expenditure Costs					
Construction Period	years	2	2	3	3
Capital Cost	£/kW	575	546	3,010	2,464
Operation and Maintenance Costs					
Costs per MW per Year	£/MW	18,876	18,876	75,408	75,408
Costs per MWh	£/MWh	0	0	15	15

9.3 Economical Assessment Methodology

The economical assessment methodology is summarised via the following steps:

Step 1) For the generic new-build CCGT power plant:

- i) Calculate the present value costs including capital expenditure (CAPEX), operation and maintenance (OPEX) and fuel costs;
- ii) Calculate the present value of net electricity generated in GWh (proportional to revenue);
- iii) Calculate the levelised costs per MWh; and,
- iv) Calculate the present value of CO_2 emitted in tonnes (proportional to cost of carbon emitted).

Step 2) For the CCGT power plant, IGCC power plant with CO_2 capture and conversion to an IGCC power plant with CO_2 capture (for the remaining power plant lifespan of 5 to 30 years in 5 year steps):

- i) Calculate the present value costs including CAPEX, OPEX and fuel costs;
- ii) Calculate the present value of net electricity generated in GWh (proportional to revenue);
- iii) Calculate the levelised costs per MWh; and,
- iv) Calculate the present value of CO2 emitted in tonnes (proportional to cost of carbon emitted).

Step 3) For the remaining power plant lifespan of 5 to 30 years in 5 year steps calculate the difference in levelised costs between an IGCC power plant with CO_2 capture and:

- i) A generic new-build CCGT power plant; and
- ii) A CCGT power plant.

Step 4) Multiply the calculated differences in levelised costs by present value of generation from the generic new-build CCGT power plant and divide by present value of CO_2 emitted for the generic new-build CCGT power plant operation for remaining project lifespan. This gives the difference in cost per tonne of CO_2 emitted.

The economical assessment methodology assumes that the generic new-build CCGT power plant remains the price setting power plant, and that there is minimal effect on wholesale price from renewables or other market mechanisms that may be introduced as part of the electricity market reform process.

The economical assessment methodology also assumes that the costs of a generic new-build CCGT power plant, and therefore the wholesale price of electricity, can be driven up through increases in carbon costs.

9.4 Economical Assessment Results

Generic New-build CCGT Power Plant

The results of Step 1 of the economical assessment are shown in Table 9.2.

Table 9.2 - Summary of Results for Generic New Build CCGT Power Plant

	Lifespan
	30
£'000 Present Value as New	
CAPEX	470,340
Fuel	1,746,414
OPEX	148,387
Total	2,365,141
Generation GWh	29,186
Levelised £/MWh	81
CO_2 Emissions '000 tonnes	9,898

The information presented in Table 9.2 is assumed to be the price setting. Accordingly, an electricity cost of £81/MWh would be achieved at an assumed load factor of 50% for a generic new-build CCGT power plant.

CCGT Power Plant

The results of Step 2 of the economical assessment, for the CCGT power plant, are shown in Table 9.3.

IGCC Power Plant with CO_2 Capture

The results of Step 2 of the economical assessment, for the IGCC power plant with CO2 capture and conversion to an IGCC power plant with CO2 capture (both with transportation and storage), are shown in Table 9.4.

It should be noted that the column relating to 30 years remaining life after conversion relates to the new-build IGCC power plant with CO2 capture.

Table 9.3 - Summary of Results for CCGT Power Plant

	Remaining Power Plant Lifespan (after conversion) (Years)					
	30	***25***	***20***	***15***	***10***	***5***
£'000 Present Value at point of Conversion						
CAPEX	233,341	194,451	155,561	116,670	77,780	38,890
Fuel	965,502	980,205	937,913	835,966	671,132	404,624
OPEX	78,798	75,871	71,160	63,568	51,341	31,648

	Remaining Power Plant Lifespan (after conversion) (Years)					
	30	***25***	***20***	***15***	***10***	***5***
Total	1,277,641	1,250,527	1,164,633	1,106,205	800,253	475,162
Generation GWh	15,102	14,537	13,639	12,167	9,779	5,904
Levelised £/MWh	85	86	85	84	82	80
CO_2 Emissions '000 tonnes	5,474	5,267	4,939	4,402	3,534	2,131

Table 9.4 - Summary of Results for IGCC Power Plant with CO2 Capture

	Remaining Power Plant Lifespan (after conversion) (Years)					
	30	***25***	***20***	***15***	***10***	***5***
£'000 Present Value at point of Conversion						
CAPEX	1,286,091	1,278,037	1,278,037	1,278,037	1,278,037	1,278,037
Fuel	775,096	660,929	619,759	552,394	443,474	267,370
OPEX	1,245,076	1,197,951	1,123,099	1,001,152	804,515	487,478
Total	3,306,263	3,136,917	3,020,895	2,831,584	2,526,027	2,032,885
Generation GWh	30,204	29,075	27,279	24,334	19,558	11,807
Levelised £/MWh	109	108	111	116	129	172
CO_2 Emissions '000 tonnes	0	0	0	0	0	0

Differences in Levelised Costs

Table 9.5 presents the differences in levelised electricity costs between an IGCC power plant with CO2 capture (Table 9.4) with either a generic new-build CCGT power plant (Table 9.2) or existing CCGT power plant (Table 9.3).

The differences in levelised costs could also be driven by a number of other, additional factors, including fuel cost rises and carbon costs. However, it is noted that a high fuel (gas) price has already been modelled.

Differences in Cost per tonne of CO_2 Emitted

Table 9.6 presents the differences in cost per tonne of CO_2 emitted between an IGCC power plant with CO_2 capture with a generic new-build CCGT power plant or existing CCGT power plant.

For the Generic New-Build CCGT Power Plant, the levelised electricity cost (£/MWh) from Table 9.5 is divided by the CO_2 Emissions '000 tonnes from Table 9.2. This value is then multiplied by the Generation (GWh) from Table 9.2 to provide the difference in cost per tonnes of CO_2 emitted (£/tonne). The same process is used for the CCGT Power Plant with values for the CO_2 Emissions '000 tonnes and Generation (GWh) from Table 9.3.

The results in Table 9.6 are presented graphically in Insert 9.1.

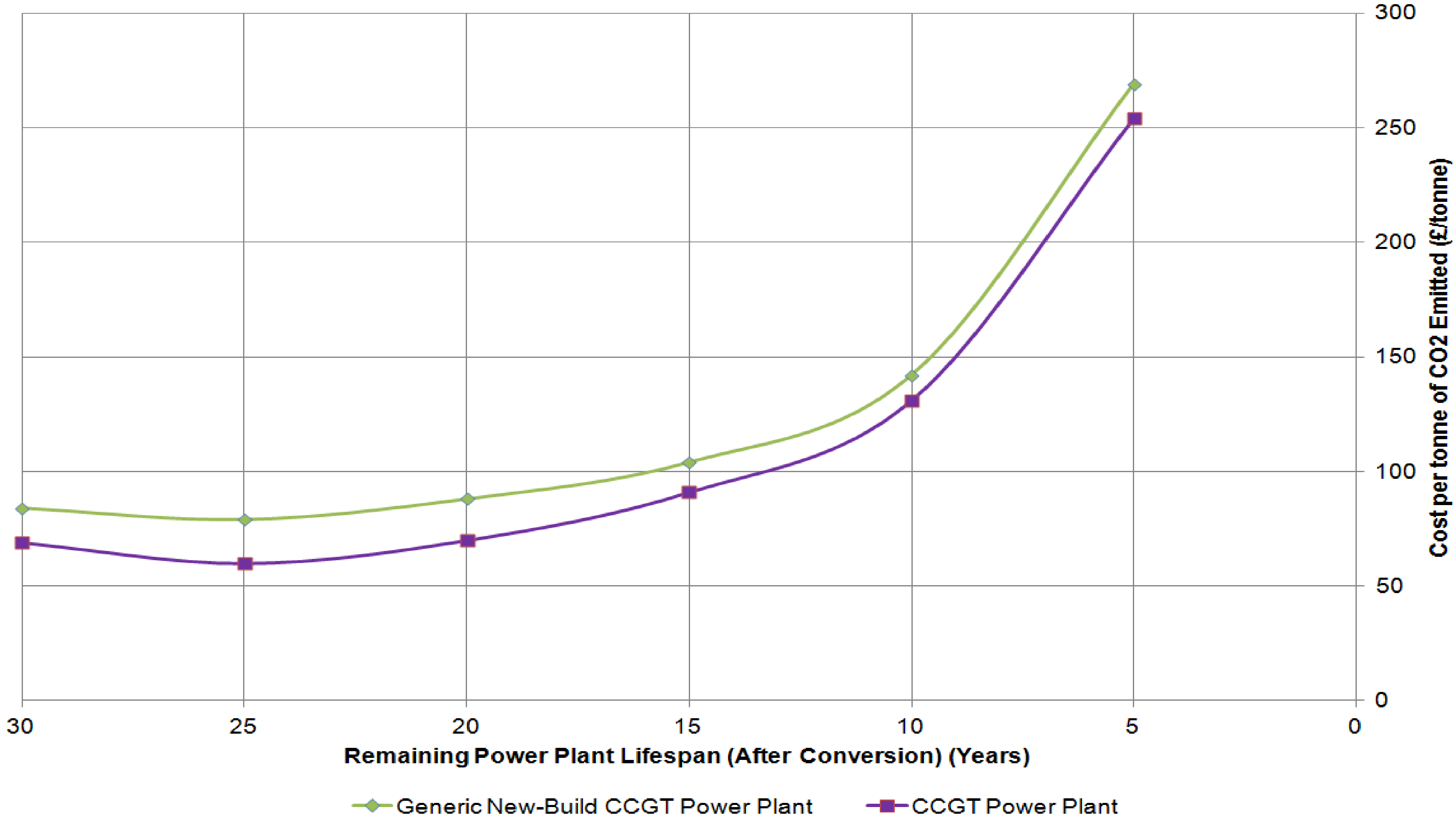
Table 9.5 - Difference in Levelised Electricity Cost (£/MWh) – Comparison of a IGCC Power Plant with CO2 Capture with Transportation and Storage with a Generic New-Build CCGT Power Plant or existing CCGT Power Plant

	Remaining Power Plant Lifespan (after conversion) (Years)					
	30	***25***	***20***	***15***	***10***	***5***
Generic New-Build CCGT Power Plant (£/MWh)	28	27	30	35	48	91
Existing CCGT Power Plant (£/MWh)	25	22	25	33	47	92

Table 9.6 - Difference in Cost per tonne of CO2 Emitted (£/tonne) – Comparison of a IGCC Power Plant with CO2 Capture with Transportation and Storage with a Generic New-Build CCGT Power Plant or CCGT Power Plant with an

	Remaining Power Plant Lifespan (after conversion) (Years)					
	30	***25***	***20***	***15***	***10***	***5***
Generic New-Build CCGT Power Plant (£/tonne)	84	79	88	104	142	269
CCGT Power Plant (£/tonne)	69	60	70	91	131	254

Insert 9-1 - Difference in Cost per tonne of CO2 Emitted (£/tonner) for an IGCC Power Plant with CO2 Capture with Transportation and Storage



9.5 Economical Assessment Conclusions

The economical assessment results (presented in Table 9.8 and Insert 9.1) show that a cost of between £60/tonne and £70/tonne of CO_2 emitted would be required in order for the conversion to an IGCC power plant with CO_2 capture to be equally attractive as the continued operation of a CCGT power plant for the remainder of the power plant's lifespan.

However, this range could only be achieved for a remaining lifespan of above or equal to 20 years. For a remaining lifespan of less than 20 years, the required cost per tonne of CO_2 emitted rises exponentially.

9.6 Assumptions and Limitations

A summary of the assumptions and limitations of this economical assessment are:

a) The costs are based on a generic project;

b) The fuel cost projections are based on DECC's published projections (high gas price and low coal price);

c) The costs are based on GBP 2013, and therefore inflation is not included;

d) A discount rate of 10 per cent is assumed;

e) All costs are derived assuming that the conversion to an IGCC power plant would start in 2013 to remove uncertainty about cost variation;

f) No account was taken of lost revenues due to power plant shut-down during conversion to an IGCC power plant;

g) No loss of electrical output is assumed following conversion to an IGCC power plant; and,

h) No CO_2 charge is assumed to be levied against any emissions from the IGCC power plant.

9B ECONOMICAL ASSESSMENT – RETROFITTING A CCGT WITH POST-COMBUSTION CARBON CAPTURE

9.7 Introduction

This section presents the results of the economical assessment which investigates the feasibility of incorporating post-combustion CO_2 capture technology onto the CCGT Plant. The economical assessment tests a number of key industry and market sensitivities.

The assumptions used in the economical assessment and analysis within this report are consistent with those used in previous post-combustion CCR Studies undertaken by WSP and align with the requirements in the CCR Guidance.

9.8 Comments on the CCR Guidance

As part of an application for consent, the CCR Guidance states (at paragraph 7) that, amongst other things, applicants will be required to demonstrate:

"the likelihood that it will be economically feasible within the power station's lifetime, to link it to the full CCS chain, covering retrofitting of capture equipment, transport and storage".

Additionally, the CCR Guidance states (at paragraph 63) that:

"Directive 2009/31/EC requires applicants to carry out an assessment of the economic feasibility of retrofitting and transport. Recital 47 states that "*The economic feasibility of the transport and retrofitting should be assessed taking into account the anticipated costs of avoided* CO_2 *for the particular local conditions in the case of retrofitting and the anticipated costs of* CO_2 *allowances in the Community. The projections should be based on the latest evidence; a review of technical options and uncertainty analysis should also be undertaken*".

Accordingly, in terms of undertaking an economical assessment the CCR Guidance notes (at paragraph 68) that a wide range of parameters are likely to be included, including:

- Assumed £ / € exchange rate;
- Future fuel prices (both absolute and relative to other fuels);
- Electricity price levels;
- Carbon price ('carbon tax');
- Power output with / without CO_2 capture, transport and storage;
- Lifetime load factor;
- Estimations of costs of retrofitting CO_2 capture equipment (construction and operation);
- Estimations of costs of transport (construction and operation);
- Estimations of costs of storage (permitting and operation); and
- Reasonable estimations of when these costs would be incurred.

It should be noted that the estimations of costs used in this economical assessment are based on those for CO_2 capture equipment, transport and storage based on technology available in 2013. The 2013 costs used are based on CCS plant design and performance parameters released by CCS technology developers to the public domain. The costs have been escalated to a 2020 basis. (Current CCS technology costs are typically proprietary, and information released into the public domain by CCS technology developers is limited).

9.9 Assessment Methodology

To investigate the economic feasibility of adding CO_2 capture equipment to the repowered units, an economic model has been developed to calculate the lifetime cost of electricity, expressed in p/kWh over the assumed 30 year lifetime.

As required by the CCR Guidance, the economic model encompasses the likely costs of CO_2 capture equipment, transport and storage. However, the effects of taxation have not been considered in the economic model.

Using the economic model, the economic feasibility of the repowered units was assessed by varying the price of EU Allowances under the EU Emissions Trading Scheme (EU ETS) / UK Carbon Floor Price (carbon price) whilst the remaining parameters remained constant. Carbon prices ranged from £0/t CO_2 to £175/t CO_2 in £25/t CO_2 increments. This allowed for the identification of the carbon price where the CCGT Power Plant with CO_2 capture equipment, transport and storage would become economically feasible.

9.10 Estimations / Assumptions

The main estimations and assumptions made in the economical assessment are detailed in Table 9.7.

TABLE 9.7 – ECONOMICAL ESTIMATIONS / ASSUMPTIONS

Variable	Estimation / Assumption	
Assumed First Year of Operation	2024	
£ to € Exchange Rate	1.14[21]	
Nominal Discount Rate	10%	
Gas Price	35.5 p/therm[22]	
Carbon Allocations	None for Power Sector – Full Purchase	
CO2 emitted before CO2 capture	339 kg/MWh	
CO2 emitted after CO2 capture (90% Capture Rate)	34 kg/MWh	
Economic Life Expectancy	30 years	
Capacity Factor (Hrs per year)	75% (6570)	
Inflation Rate per Annum	2%	
	No CCS	CCS-First of Kind-Dedicated Storage
Net Power Output	471 MW	428 MW
Heat Rate LHV	6173 kJ/kWh	7078 kJ/kWh
Construction Cost [23]	660.5 £/kW	1132 £/kW
Construction Period	3 years	4 years
LTSA cost	1551 £/fired-hour	4829 £/fired-hour
Transport and Storage Capex[24]	-	132.8 £/kW
Transport Opex	-	426 £'000
Storage Opex	-	213 £'000

As outlined in Table 9.7, the scenario modelled is a first of a kind plant, with dedicated transport and storage. The lifetime cost of electricity would reduce for a Nth of a kind plant with shared transport and storage infrastructure and would make retrofitting a carbon capture plant more viable. However, as the CCR Guidance states that outsourcing transport and storage cannot be assumed, this scenario has not been looked at.

[21] *Exchange Rate taken April 2020*

[22] *Taken from 2019 average real natural Gas price (pence/kWh) – "BEIS - Average prices of fuels purchased by the major UK power producers, 26 March 2020". One therm is equal to 29.3 kWh*

[23] *2013 costs inflated to 2020 costs. 2013 costs based on CCS plant design and performance parameters released by CCS technology developers to the public domain.*

[24] *Using comparable transport and storage cost used in the IGCC scenario (FOAK with dedicated transport and storage) but based on Net Plant Output and inflated to 2020 costs..*

9.11 Economical Assessment

The results of the economical assessment provide the cross-over point when the lifetime cost of electricity (£/MWh) for a CCGT plant equipped with carbon capture equipment becomes equal to or lower than the lifetime cost for a CCGT plant with no carbon capture.

The results have been presented graphically in Insert 9.2, which shows how the lifetime cost of electricity (£/MWh) (vertical axis) varies with different assumed carbon prices (Financial penalty per tonne of CO2 emitted i.e. 'carbon tax') (horizontal axis).

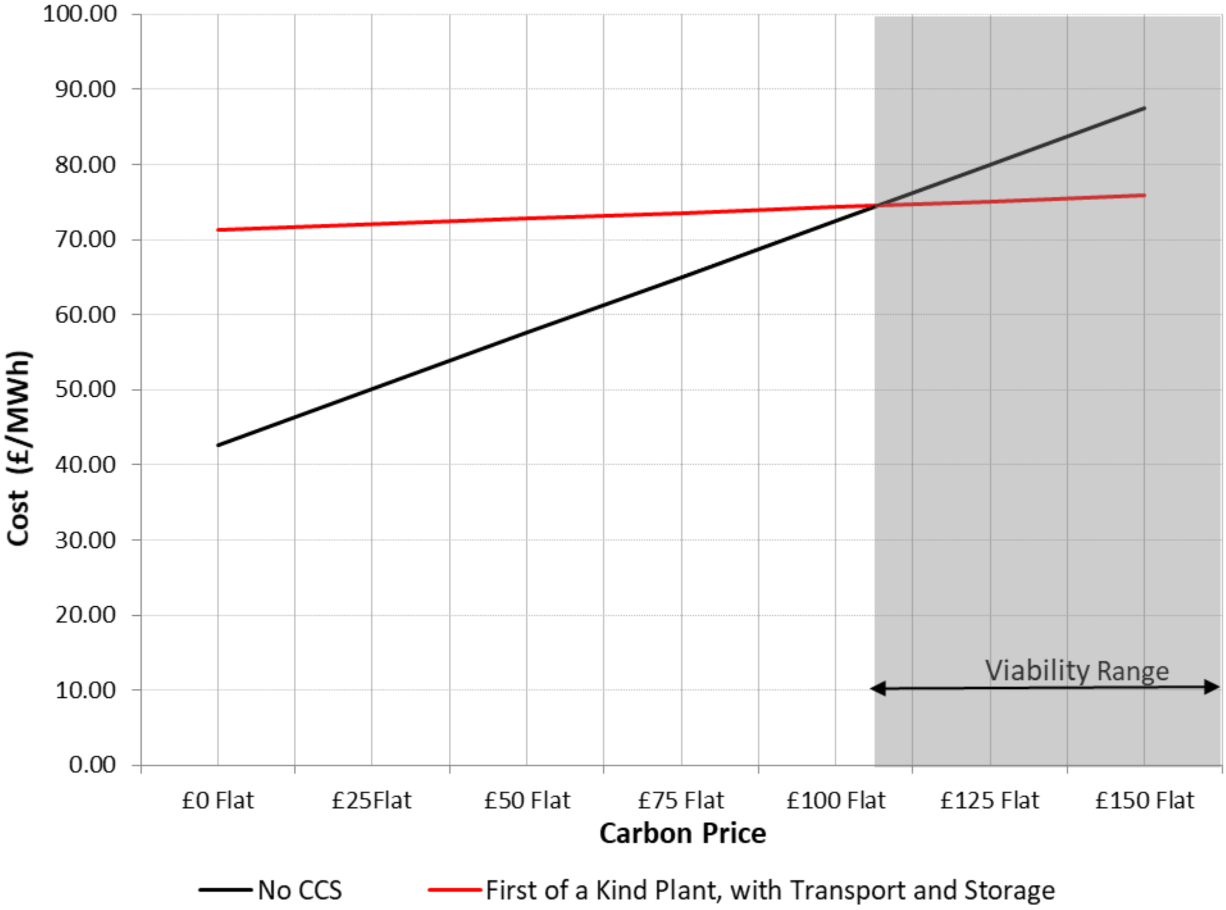
For a CCGT Plant with no carbon capture, the lifetime cost of electricity ranges between £42.69/MWh (at £0/t CO_2 carbon price) and £87.43/MWh (at £175/t CO_2 carbon price).

For a CCGT Plant with carbon capture equipment, the lifetime cost of electricity ranges between £71.34/MWh (at £0/t CO_2 carbon price) and £75.83 (at £175/t CO_2 carbon price). As only 10% of CO2 is now being released (assuming 90% capture rate), there is only a small difference in the lifetime cost of electricity as the carbon price changes from £0/t CO_2 to £175/t CO_2.

Although there is a larger CAPEX cost, larger O&M cost and lower plant efficiency associated with the CCGT plant with carbon capture, there is a cross-over point where it becomes more financially favourable. For this project, it is when the financial penalty per tonne of CO2 emitted becomes £107/t CO_2.

In accordance with the UK government Budget announcement 2016, the UK Carbon Price Floor is currently capped at £18/t CO_2, until 2021. As such, it is currently not economically favourable to have a carbon capture plant.

Insert 9.2 – Results for the Economic Assessment of a CCGT Power Plant with CO2 Capture



9.12 Economical Assessment Conclusions

The results of the economical assessment determines the cross-over point when the lifetime cost of electricity (£/MWh) for a CCGT plant equipped with carbon capture equipment becomes equal to or lower than the cost for a CCGT plant with no carbon capture. This cross-over point has been determined to be £107/t CO_2.

It is again worth highlighting that the scenario modelled is a first of a kind plant, with dedicated CO2 transport and storage but for a Nth of a kind plant with shared CO_2 transport and storage infrastructure, the lifetime cost of electricity would be reduced and making the project viable at a lower carbon price.

10 REQUIREMENT FOR HAZARDOUS SUBSTANCES (HSC)

Alongside the information provided in the 2013 Submission, this section has been updated to include an additional scenario, the chemical / substances involved in a CCGT Power Plant with Post-Combustion CO2 Capture technology. The updated information is comparative in detail to the information provided in the 2013 Submission.

10.1 Evaluation of the Potential Requirement for HSC

The presence of certain hazardous substances on, under or above land at or above set threshold quantities (Controlled Quantities) may require a Hazardous Substances Consent (HSC) under the Planning (Hazardous Substances) Act 1990 (as amended). The threshold quantities (Controlled Quantities) are set out in the Planning (Hazardous Substances) Regulations 1992 (as amended).

a) Accordingly, this Section evaluates the potential requirement for a HSC based on:

b) The chemical / substances involved in a CCGT power plant process;

c) The chemical / substances involved in a CCGT power plant with post-combustion CO2 capture process;

d) The chemicals / substances involved in an IGCC power plant with pre-combustion CO_2 capture process; and,

e) The captured CO_2.

10.2 Chemicals / Substances involved in the CCGT Power Plant Process

Operation of a CCGT power plant would require the use natural gas as a fuel.

The Planning (Hazardous Substances) Regulations 1992 (as amended) advise that the Controlled Quantity of natural gas is 15 tonnes. Natural gas will be delivered via a dedicated gas pipeline, and no natural gas will be stored on-site.

10.3 Chemical / Substances involved in the CCGT power plant with post-combustion CO2 capture Process

The feasibility of CCR for the CCGT has been assessed on the basis on the best currently available technology, which, for CO2 capture from flue gases (post-combustion CO2 capture), is chemical absorption using amine solvents.

The most likely amine solvent is MEA, which is not normally present on gas fired power plant sites. The MEA that would be present at the CCGT would either be stored as a pure substance, or be used in the CO2 capture process as a solution. These are referred to as MEA substance and MEA preparation respectively.

In terms of MEA substance, the current classifications are XN R20/21/22 and C R34. These classifications translate as 'harmful' and 'corrosive'. In terms of MEA preparation, a solution of ≥ 25% would have the same classifications as MEA substance.

Accordingly, in terms of both MEA substance and MEA preparation, the current classifications are such that a HSC is not required. In addition, discussions have previously been held between WSP UK Limited and the DECC (now BEIS) Carbon Capture Readiness Team on the risks associated with MEA. In these discussions, DECC confirmed that the HSE did not consider MEA to be subject to any requirement for a HSC or be subject to any on-site storage limits.

10.4 Chemicals / Substances involved in the IGCC Power Plant with CO2 Capture Process

As CO2 capture increases the concentration of hydrogen in the syngas, operation of an IGCC power plant with CO2 capture would require the use a hydrogen-rich syngas as a fuel.

The Planning (Hazardous Substances) Regulations 1992 advise that the Controlled Quantity of hydrogen is 2 tonnes. The hydrogen-rich syngas will be produced, for the most part, for immediate use within the gas turbine, and no hydrogen will be stored on-site.

In addition, operation of an IGCC power plant would potentially require the storage of oxygen.

The Planning (Hazardous Substance) Regulations 1992 advise that the Controlled Quantity of liquid oxygen is 500 tonnes. It is not anticipated that there would be any liquid oxygen stored on-site, and any gaseous oxygen stored on-site would likely be below 500 tonnes.

10.5 Captured CO2

As noted in the CCR Guidance, it may be that (during operation with CO2 capture, compression, transportation and storage) dense phase CO2 would be present on-site and within the CO2 pipeline once the captured CO2 is compressed in preparation for transport. Whilst dense phase CO2 is not currently classified as hazardous, it is now recognised that an accidental release of large quantities of dense phase CO2 could result in a major accident. As such, there is currently extensive ongoing research into the hazard potential of dense phase CO2. The results of this ongoing research will inform future decisions on dense phase CO2 and whether a classification review is necessary.

As a result, and as recommended in the CCR Guidance, if it is envisaged that any dense phase CO2 will be stored on site the principles of the Planning (Hazardous Substance) Regulations 1992 (as amended) and the Control of Major Accident Hazard Regulations 2005 should be applied by early adopters of CCS during design, construction and operation.

In terms of the CO2 capture and compression plant / equipment, it is anticipated that no CO2 (gaseous or dense phase) will be stored on-site.

In terms of CO2 transport, CO2 (gaseous and / or dense phase) will be present in CO2 pipelines on-site.

Application of the Planning (Hazardous Substances) Regulations 1992

Subject to the classification review, these CO2 pipelines may fall inside the scope of the Planning (Hazardous Substance) Regulations 1992 (as amended). However, until the classification is known and the information on the Controlled Quantity is available, it is not known whether the Planning (Hazardous Substances) Regulations 1992 (as amended) would apply. In this regard, C.GEN will hold informal discussions with the LPA about the potential issues surrounding dense phase CO2, including the implications behind the possible presence of small amounts on site. These informal discussions will continue until further information concerning the classification of dense phase CO2 is available. This will ensure that there is early identification of any potential implications on the LPA’s long term plan for the area. However, at this stage is it felt that no formal discussions or preparations are necessary.

Application of the Control of Major Accident Hazard Regulations 2005

These CO_2 pipelines do not fall inside the scope of the Control of Major Accident Hazard Regulations 2005.

10.6 Conclusion of the Potential Requirement for HSC

On the basis of the proposed CO_2 capture technology selected and the current classifications of the chemicals / substances which are likely to be on site, it is concluded that a HSC is not required at this stage.

If a HSC is required at the point of construction / conversion to CO_2 capture, an application would be made at this stage. This is because any detailed information which would be required for the application will not be known until this stage.

10.7 CCR Status and Full Development of CCS

As required by the CCR Guidance, this 'Requirement for Hazardous Substance Consent' will be reviewed on an ongoing basis as part of the Status Report to be submitted every 2 years (from the first date of commercial operation of the CCGT power plant until construction / conversion to CO_2 capture), with a view to incorporating any developments into an updated design.

11 CONCLUSIONS

This document is a CCR Feasibility Study which was originally undertaken by PB on behalf of C.GEN in 2013. This document has been updated by WSP in 2020 to include a carbon capture ready solution for operation of a generating station as a CCGT plant (using natural gas as fuel). This is in addition to the carbon capture ready solution for operation of a generating station as an IGCC Plant (using 100% coal as fuel), as presented in the 2013 Submission.

It is intended to provide the additional information (with reference to the CCR Guidance and Draft Supplementary Guidance) to support the application for a DCO amendment to extend the implementation period pursuant to the DCO, and an ancillary change to the DCO so as to reserve land for a post-combustion solution.

A checklist of this additional information (with reference to the relevant requirements of the CCR Guidance and Draft Supplementary Guidance) is provided in Appendix B, in the 2013 Submission. On review, the checklist is valid for the IGCC power plant with pre-combustion CO2 capture and has been updated as appropriate to reflect changes in the document. Table B3 has been added to Appendix B, providing an equivalent checklist for the CCGT Power Plant with Post-Combustion CO2 Capture. Appendix B also contains references to where the additional information as required by the CCR Guidance and the Draft Supplementary Guidance can be found within this Document.

It is considered that the information provided in this Document has successfully demonstrated that:

a) In terms of the CCR Guidance:

   i. Sufficient space is available to accommodate either of the proposed CO_2 capture technologies;

   ii. It will be technically feasible to retrofit either of the proposed CO_2 capture technologies;

   iii. There are suitable offshore CO_2 storage areas available;

   iv. It will be technically feasible to transport the captured CO_2 to the offshore CO_2 storage areas; and

   v. It may be economically feasible, within the lifetime of the Project, to implement either of the proposed CO_2 capture technologies (including transport and storage).

b) In terms of the Draft Supplementary Guidance:

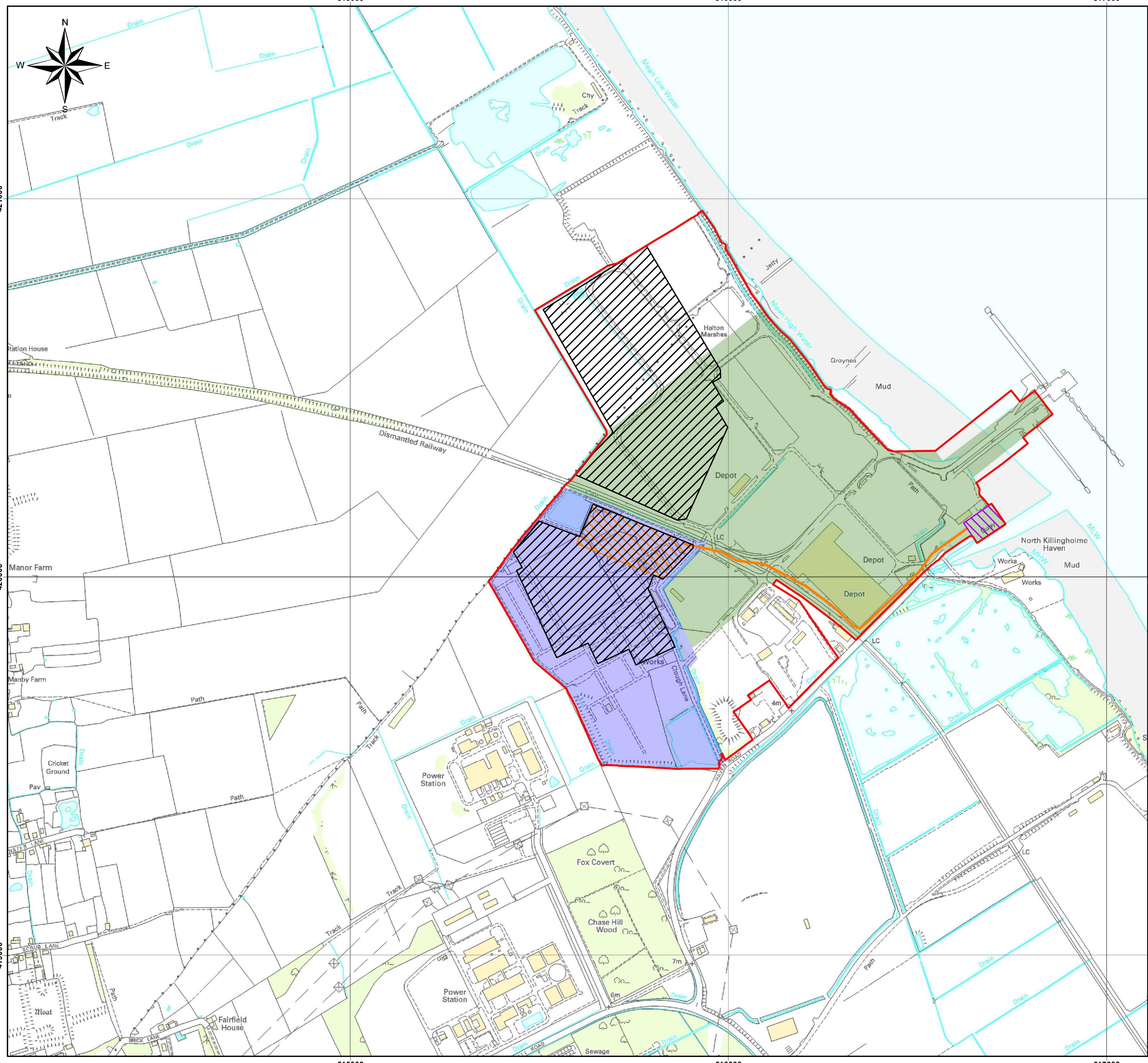
   i. It will be technically feasible to retrofit the proposed CO_2 capture technologies;

   ii. The environmental impacts of retrofitting either of the proposed CO_2 capture technologies have been fully considered; and,

   iii. The Project complies with the requirements of the CCR Guidance.

Accordingly, the Project (and the DCO non-material change application) complies with the CCC and CCR Policy within NPS EN-1 and the requirements of the CCR Guidance and the Draft Supplementary Guidance.

FIGURES



Legend

- Principal Project Area
- Construction Laydown Areas
- Wharfage Area (Fuel Unloading)
- Fuel Conveyor Route
- Covered Fuel Storage Area
- Operations Area
- Cooling Water Connection

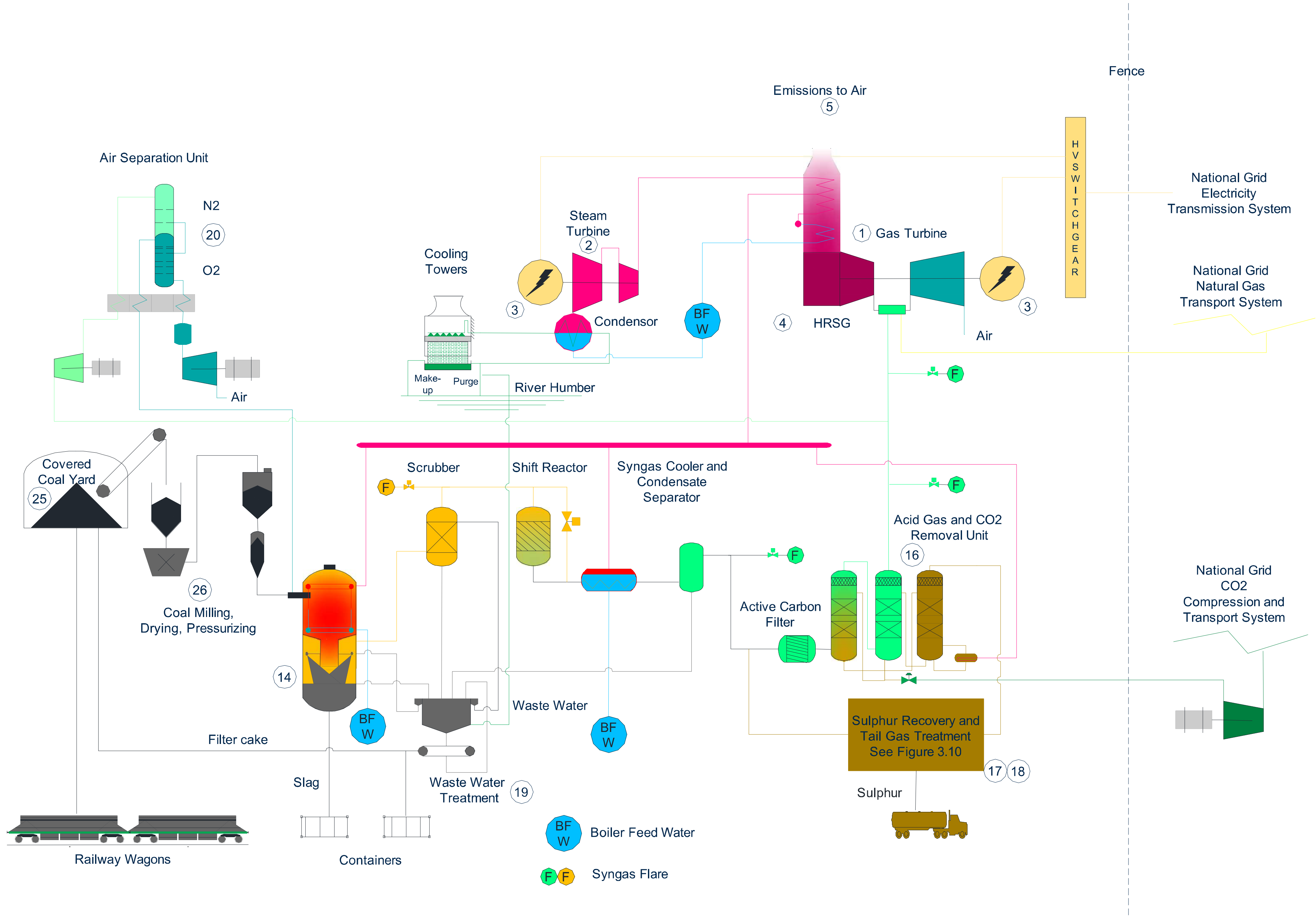
North Killingholme Power Project

Principal Project Area

DOCUMENT REF:	SITE DESIGN VERSION:	DATE:
64042A-CC-01	v2	20/02/2013
BAR SCALE: NOT TO SCALE	0 0.1 0.2 0.3 0.4 Km	
DRAWN BY: RT	CHECKED BY: EA	APPROVED BY: CL

PARSONS BRINCKERHOFF

FIGURE 1



North Killingholme Power Project

Schematic Representation of the IGCC Principle

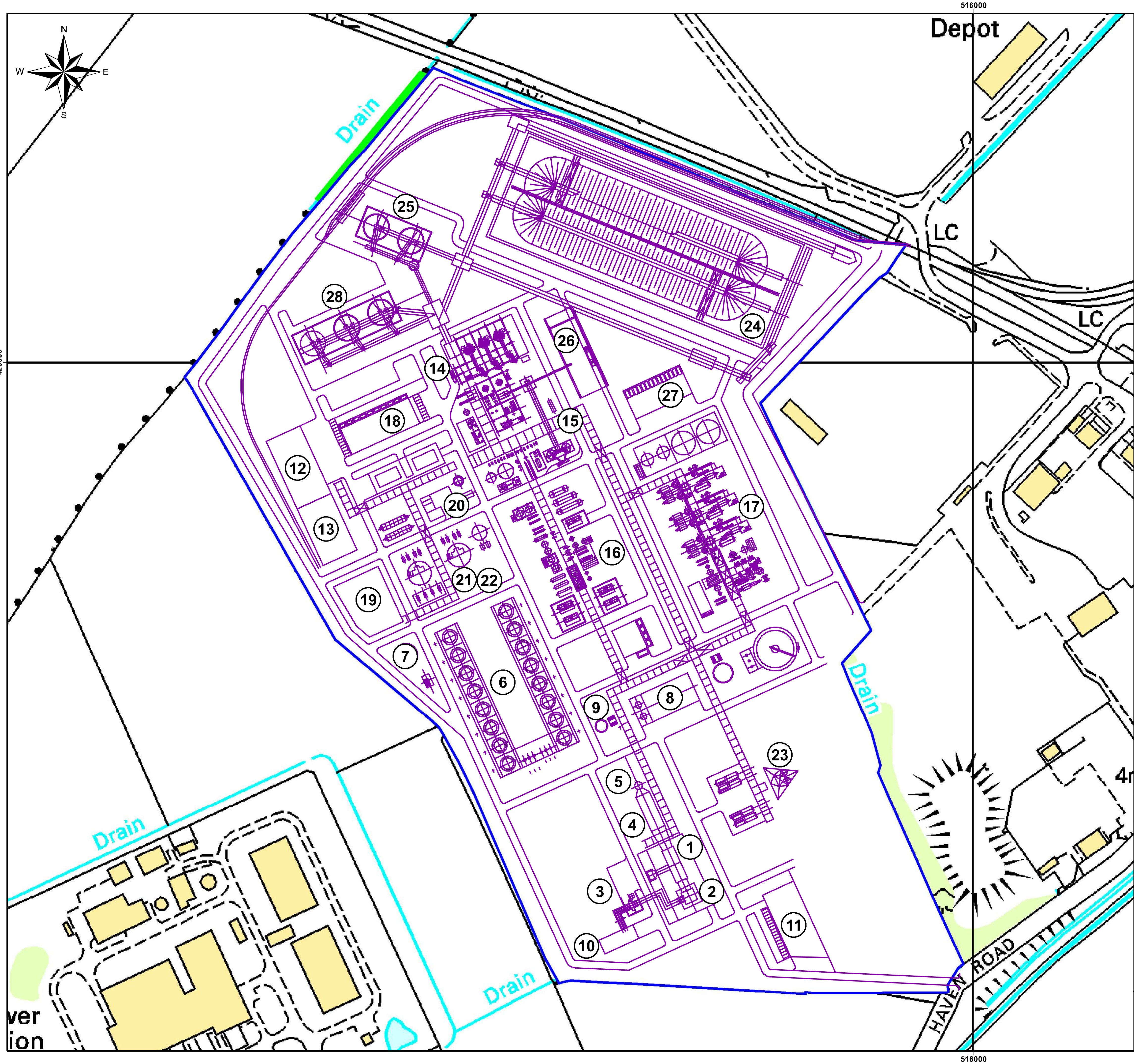
DOCUMENT REF:	SITE DESIGN VERSION:	DATE:
64042A-CC-02	v2	20/02/2013

BAR SCALE
NOT TO SCALE

DRAWN BY:	CHECKED BY:	APPROVED BY:
RT	EA	CL

PARSONS BRINCKERHOFF

FIGURE 2



Legend

- Indicative IGCC Layout
- Operations Area
- Area for Location of CO2 Export Pipeline

1. Gas Turbine
2. Steam Turbine
3. Generator / Transformer
4. Heat Recovery Steam Generator
5. Main Stack
6. Hybrid Cooling Towers
7. Raw / Fire Water Storage
8. Raw Water Treatment Plant
9. Demineralised Water Storage
10. Gas Insulated Switchgear
11. Administration Building
12. Workshop / Warehouse
13. Material Storage
14. Gasifier
15. Syngas Treatment / Conditioning
16. Acid Gas Removal
17. Sulphur Recovery and Tail-Gas Treament
18. Main E.S.S.
19. Waste Water Treatment
20. Air Separation Unit
21. Nitrogen Storage Tank
22. Oxygen Storage Tank
23. Flare Stack
24. Covered Fuel Storage Area
25. Fuel Preparation
26. Slag Storage Area
27. Filter Cake Storage Area
28. Biomass / Limestone Storage

North Killingholme Power Project

Outline Plot Level Plan/ Preliminary Plot Plan

DOCUMENT REF:	SITE DESIGN VERSION:	DATE:
64042A-CC-03	v1	21/01/2013

BAR SCALE
NOT TO SCALE
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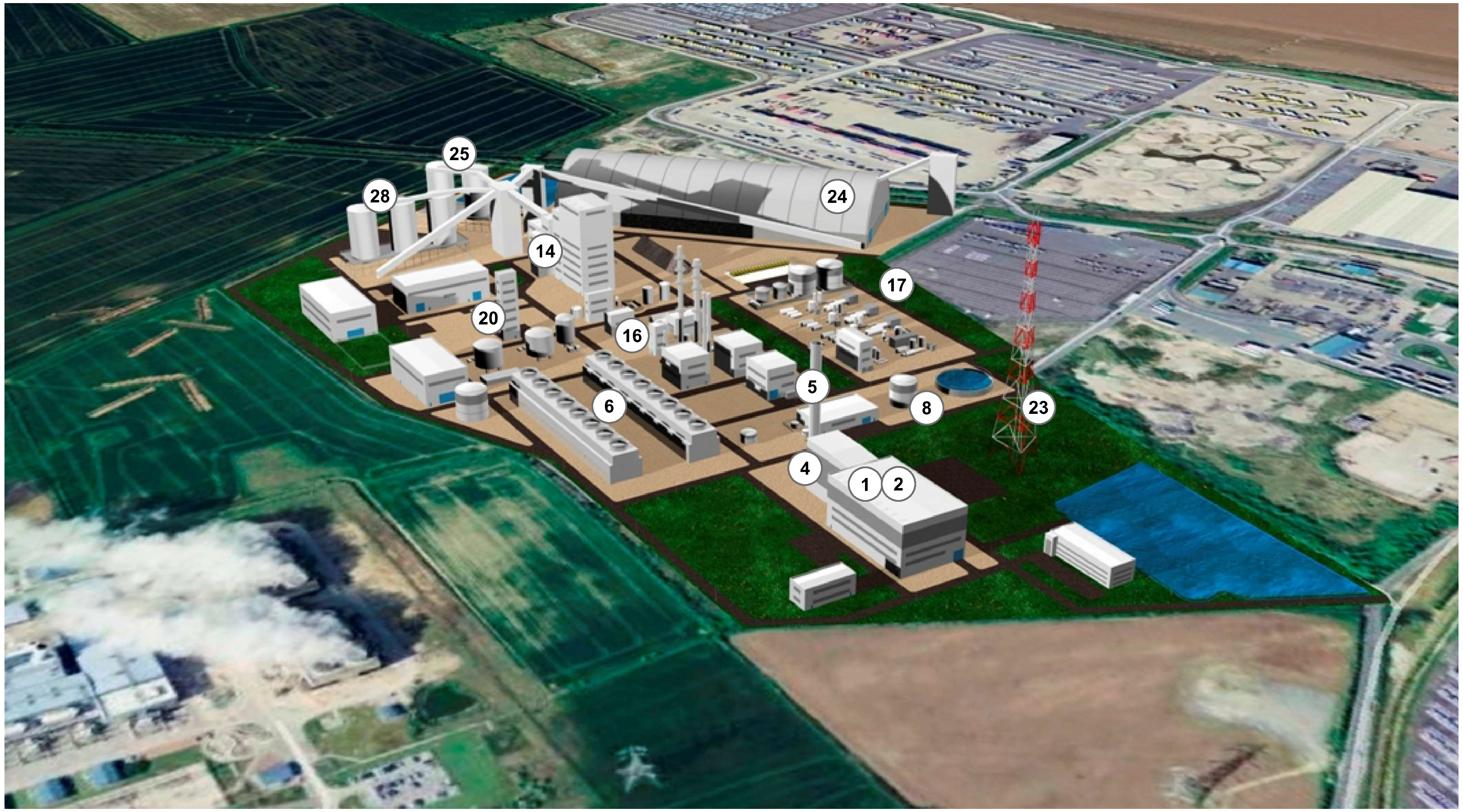
DRAWN BY:	CHECKED BY:	APPROVED BY:
RT	EA	CL

PARSONS BRINCKERHOFF

FIGURE 3



Legend

1. Gas Turbine
2. Steam Turbine
4. Heat Recovery Steam Generator
5. Main Stack
6. Hybrid Cooling Towers
8. Raw Water Treatment Plant
14. Gasifier
16. Acid Gas Removal
17. Sulphur Recovery and Tail-Gas Treatment
20. Air Separation Unit
23. Flare Stack
24. Covered Fuel Storage Area
25. Fuel Preparation
28. Biomass / Limestone Storage

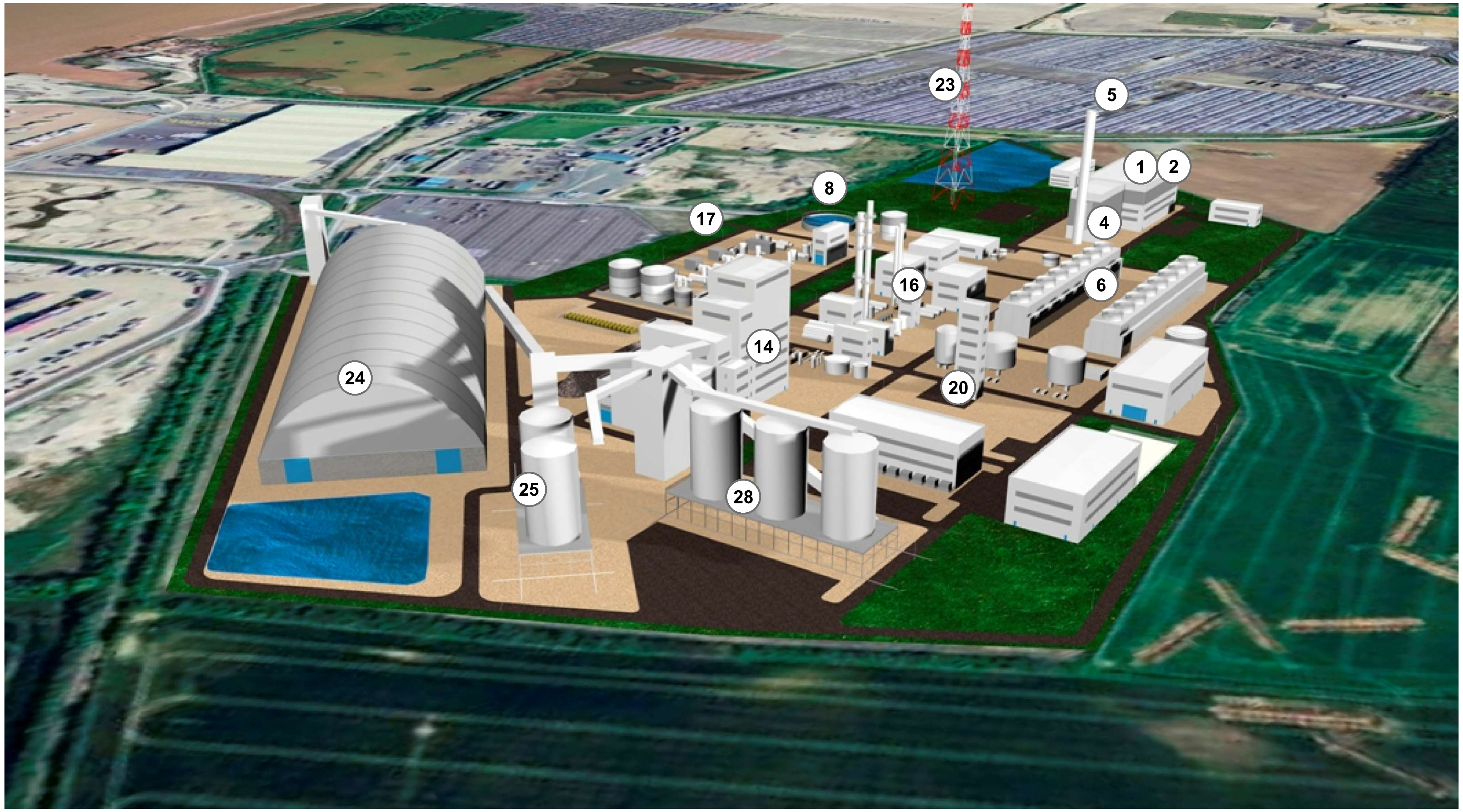
North Killingholme Power Project

Indicative 3D Project Rendering (view from south west)

DOCUMENT REF:	SITE DESIGN VERSION:	DATE:
64042A-CC-04	v1	21/01/2013
BAR SCALE		
DRAWN BY: RT	CHECKED BY: EA	APPROVED BY: CL

PARSONS BRINCKERHOFF

FIGURE 4



Legend

1. Gas Turbine
2. Steam Turbine
4. Heat Recovery Steam Generator
5. Main Stack
6. Hybrid Cooling Towers
8. Raw Water Treatment Plant
14. Gasifier
16. Acid Gas Removal
17. Sulphur Recovery and Tail-Gas Treatment
20. Air Separation Unit
23. Flare Stack
24. Covered Fuel Storage Area
25. Fuel Preparation
28. Biomass / Limestone Storage

North Killingholme Power Project

Indicative 3D Project Rendering (view from north west)

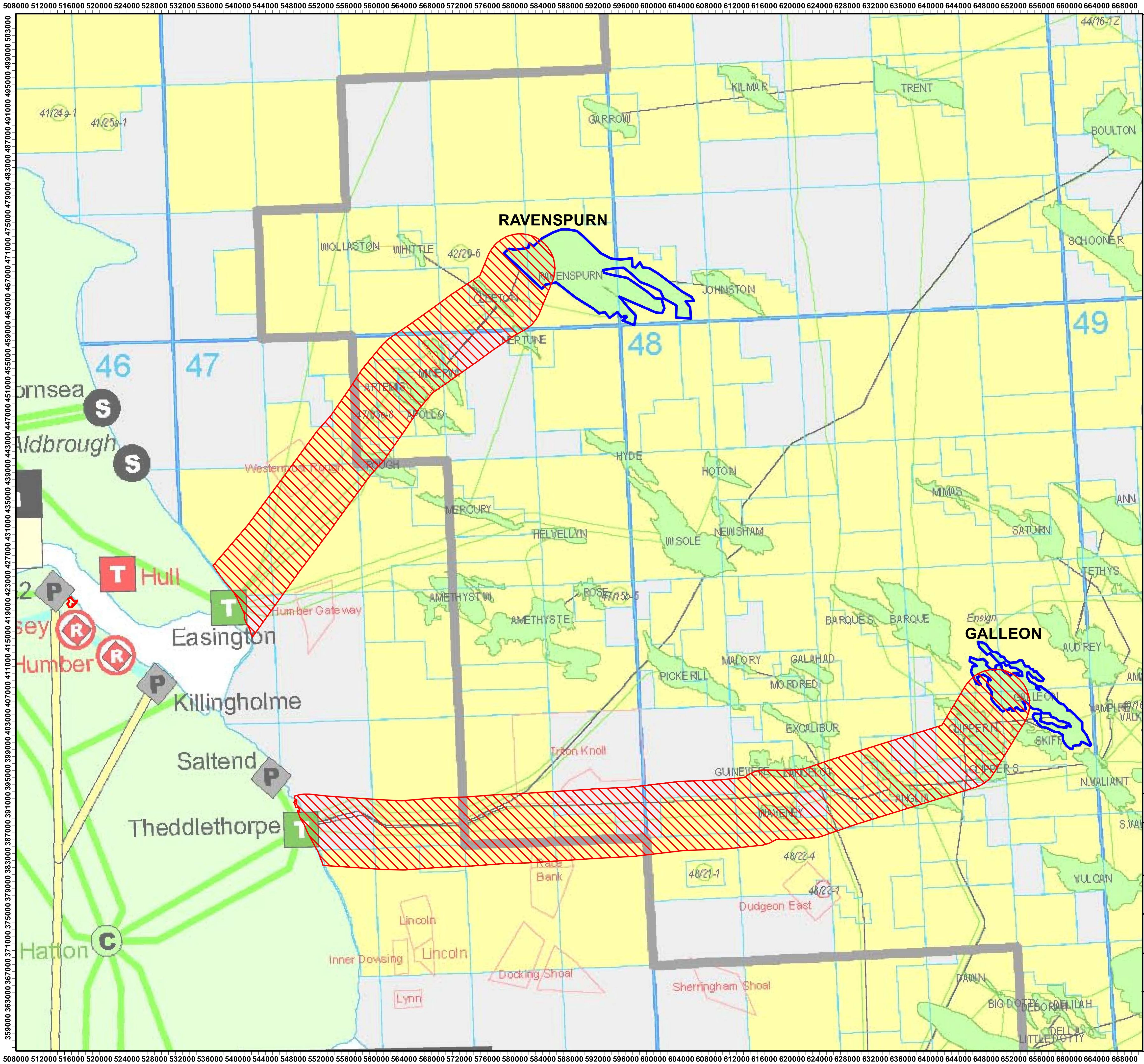
DOCUMENT REF:	SITE DESIGN VERSION:	DATE:
64042A-CC-05	v1	21/01/2013

BAR SCALE

DRAWN BY:	CHECKED BY:	APPROVED BY:
RT	EA	CL

PARSONS BRINCKERHOFF

FIGURE 5



Legend

- Principal Project Area
- CO2 Transport Pipelines (10 km Route Corridor)
- Potential CO2 Storage Sites

North Killingholme Power Project

Off-Shore CO2 Storage Areas & Proposed Pipeline Route Corridors

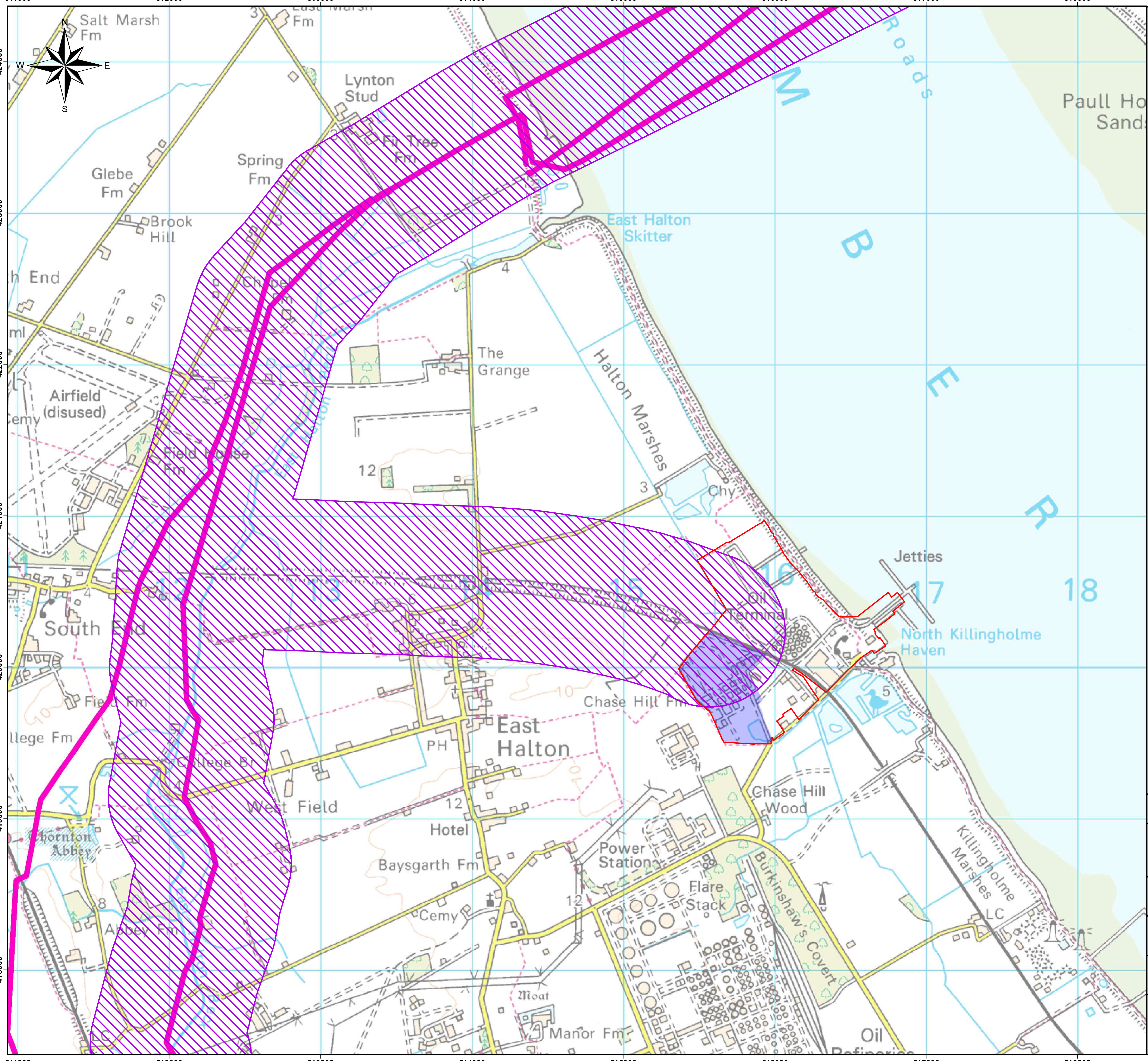
DOCUMENT REF:	SITE DESIGN VERSION:	DATE:
64042A-CC-06	v1	21/01/2013

BAR SCALE	
NOT TO SCALE	0 6 12 18 24 Km

DRAWN BY:	CHECKED BY:	APPROVED BY:
RT	EA	CL

PARSONS BRINCKERHOFF

FIGURE 6



Legend

- Principal Project Area
- CO2 Transport Pipeline (1 km Route Corridor)
- Operations Area
- National Grid High Pressure Gas Network

North Killingholme Power Project

Proposed On-Shore CO2 Pipeline Route Corridor (near Application Site)

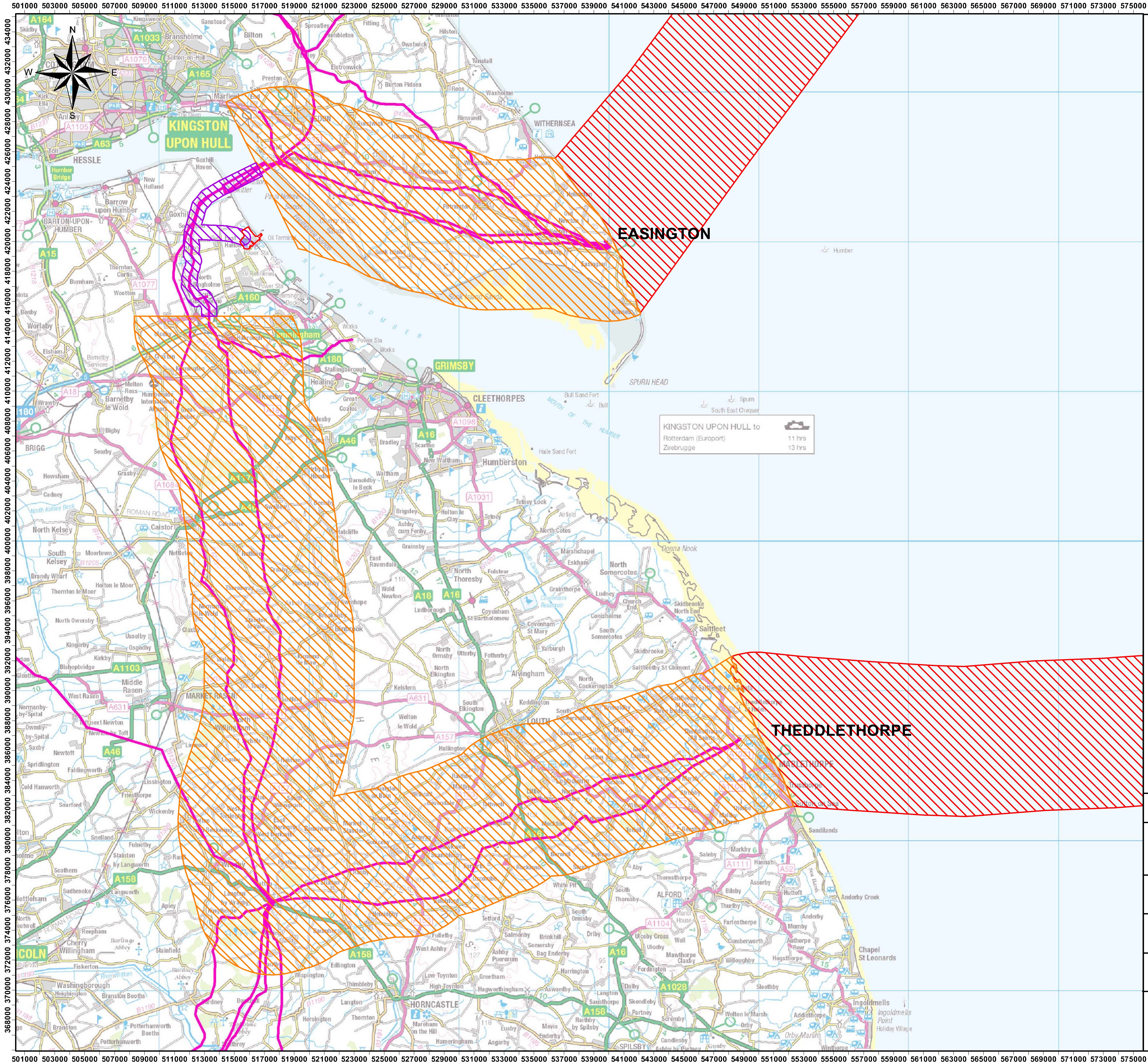
DOCUMENT REF:	SITE DESIGN VERSION:	DATE:
64042A-CC-07	v1	21/01/2013

BAR SCALE: 1:25,000 @ A3 — 0, 0.3, 0.6, 0.9, 1.2 Km

DRAWN BY:	CHECKED BY:	APPROVED BY:
RT	EA	CL

PARSONS BRINCKERHOFF

FIGURE 7



Legend

- Principal Project Area
- CO2 Transport Pipeline (1 km Route Corridor)
- CO2 Transport Pipeline (10 km Route Corridor)
- CO2 Transport Pipeline (Off-Shore, 10 km Route Corridor)
- Operations Area
- National Grid High Pressure Gas Network

North Killingholme Power Project

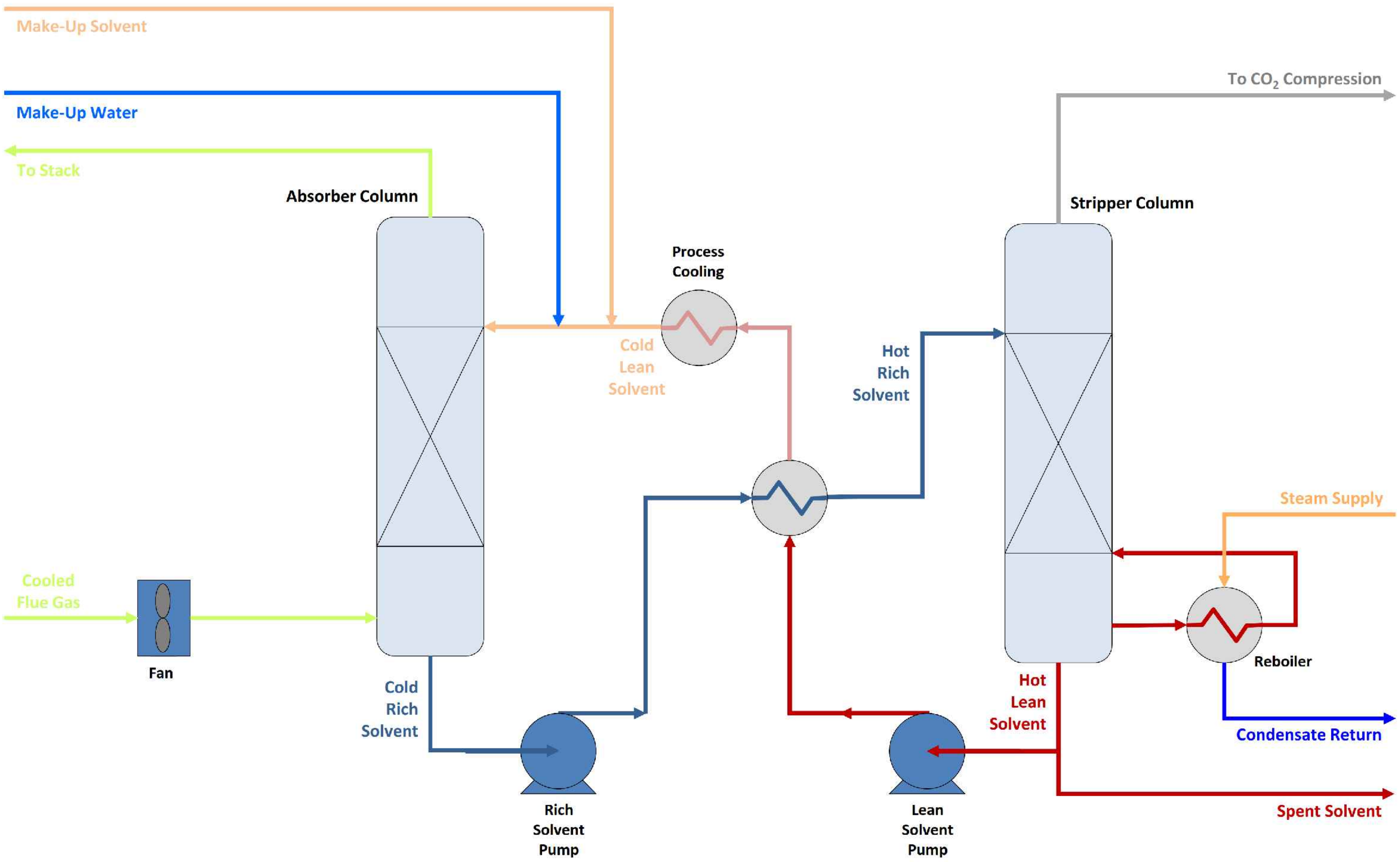
Proposed On-Shore CO2 Pipeline Route Corridor

DOCUMENT REF:	SITE DESIGN VERSION:	DATE:
64042A-CC-08	v1	21/01/2013
BAR SCALE 1:250,000 @ A3	0 3 6 9 12 Km	
DRAWN BY: RT	CHECKED BY: EA	APPROVED BY: CL

PARSONS BRINCKERHOFF

FIGURE 8

DO NOT SCALE



REV	DATE	BY	DESCRIPTION	CHK	APP
01	09/04/2020	AY	FIRST ISSUE	RM	RM

DRAWING STATUS:
Submitted For Reference

WSP

8 First Street, Manchester, M15 4GU, UK
T+ 44 (0) 161 200 5000
wsp.com

CLIENT:
C.GEN

PROJECT:
The North Killingholme (Generating Station) (Correction) Order 2015

TITLE:
Schematic of Post Carbon Capture

SCALE @ A3:	CHECKED:		APPROVED:
NTS	RM		RM
PROJECT No:	DESIGNED:	DRAWN:	DATE:
70055743	AY	AY	21/04/2020

DRAWING No: FIGURE 9
REV: 01

DO NOT SCALE

LEGEND

CCGT Layout (CCGT Plant equipment shown greyed out)

1. Gas Turbine
2. Steam Turbine
3. Generator / Transformer
4. Heat Recovery Steam Generator
5. Main Stack
6. Hybrid Cooling Towers
7. Raw / Fire Water Storage
8. Raw Water Treatment Plant
9. Demineralised Water Storage
10. Gas Insulated Switchgear
11. Administration Building
12. Workshop / Warehouse
13. Material Storage
19. Waste Water Treatment

Carbon Capture Storage Area

20. Truck Un-/Loading Station
21. Reclaimer Unit
22. EI&C
23. Area Storage
24. Steam and Condensate
25. Admin Building
26. Flue Gas Cooler
27. Flue Gas Cooler Water Pumps
28. Flue Gas Blower
29. Flue Gas Cooler Water Cooler
30. Absorber
31. Rich Solvent Pumps
32. Lean Solvent Cooler
33. Lean Solvent Pumps
34. Lean Solvent Flash Vessel
35. Lean Solvent Flash Compressor Unit
36. Desorber Unit
37. CO2 Purification Units
38. CO2 Compressor Unit

Operations Area

CCR Space Provision Area - Post Combustion CO2 Capture

REV	DATE	BY	DESCRIPTION	CHK	APP
01	10/07/2020	AY	FIRST ISSUE	RM	RM

DRAWING STATUS: Submitted for Reference

8 First Street, Manchester, M15 4GU, UK
T+ 44 (0) 161 200 5000
wsp.com

CLIENT: C.GEN

PROJECT: North Killingholme Power Project

TITLE: Outline Plot Level Plan for CCGT Power Plant with Post-Combustion CO2 Capture

SCALE @ A0: 1:1000	CHECKED: RM		APPROVED: RM
PROJECT No: 70055743	DESIGNED: AY	DRAWN: AY	DATE: 10.07.20

DRAWING No: 70055743-DWG-G-002 REV: 01

APPENDIX A – RELEVANT SECTIONS OF THE EU DIRECTIVES

RELEVANT SECTIONS OF EU DIRECTIVE ON THE GEOLOGICAL STORAGE OF CARBON DIOXIDE

Annex

(47) The transition to low-carbon power generation requires that, in the event of fossil fuel power generation, new investments be 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 33

Amendment of Directive 2001/80/EC

In Directive 2001/80/EC, the following Article shall be 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 2009/31/EC of the European Parliament and of the Council of 23 April 2009 on the geological storage of carbon dioxide (*), 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 140, 5.6.2009, p. 114".

RELEVANT SECTIONS OF EU DIRECTIVE ON INDUSTRIAL EMISSIONS (INTEGRATED POLLUTION PREVENTION AND CONTROL)

Article 36

Geological storage of carbon dioxide

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 licence or, in the absence of such a procedure, the original operating licence is granted after the entry into force of Directive 2009/31/EC of the European Parliament and of the Council of 23 April 2009 on the geological storage of carbon dioxide(1), have assessed whether the following conditions are met:

(a) suitable storage sites are available,

(b) transport facilities are technically and economically feasible,

(c) it is technically and economically feasible to retrofit for carbon dioxide capture.

2. If the conditions laid down 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 carbon dioxide 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 140, 5.6.2009, p. 114.

APPENDIX B – CCR / CCS REQUIREMENTS CHECKLISTS

Table B1 – Carbon Capture Readiness (CCR) Requirements Checklist for a IGCC Power Plant with Pre-Combustion CO2

Table B2 – Carbon Capture and Storage Requirements for a IGCC Power Plant with Pre-Combustion CO2

Table B3 – Carbon Capture Readiness (CCR) Requirements Checklist for a CCGT Power Plant with Post-Combustion CO2 Capture

Table B1 – Carbon Capture Readiness Requirements Checklist

Requirement	Description	Reference
B1 (Design, Planning Permissions and Approvals)	A pre-feasibility level conceptual capture retrofit study for the power plant with carbon dioxide (CO2) capture should be supplied for assessment showing how the proposed pre-combustion capture plant is technically feasible.	This Document
	An outline plot level plan for the plant retrofitted with capture should be provided.	Section 5.2 / Figure 3
B2 (Power Plant Location)	The work undertaken on the CO_2 transport and storage should be referenced.	Section 7 / Section 8
	The exit point of any emission and effluent streams from the cartilage of the capture plant should be provided.	Section 5.2 / Figure 3
B3 (Space Requirements)	A outline plot level plan is required clearly identifying unit block sizes for the coal storage and preparation, coal gasification, CO shift, cooling and condensation, ASU, CO_2 capture, solvent regeneration, sulphur recovery, compression, dehydration (if required), associated utilities (including vent stack) and storage equipment. The HRSG and fuel gas conditioning system should also be indicated.	Section 5.2 / Figure 3
B4 (Gas Turbine Combined Cycle Unit Operation with Hydrogen-Rich Fuel Gas)	The gas turbine must be able to be modified to operate with the proposed hydrogen-rich fuel gas, whilst meeting any environmental restrictions on emissions. A statement confirming that the gas turbine could be modified to fire on hydrogen-rich fuel gas is required.	Section 6.2
B5 (Heat Recovery Steam Generator (HRSG) and Plant Steam Cycle)	The HRSG must be designed to accommodate the changed flue gas composition and temperatures after pre-combustion capture retrofit. The steam cycle as a whole must also be designed to accommodate the needs of the hydrogen production facility to allow for reasonable thermal integration and hence overall	Section 6.3

Requirement	Description	Reference
	plant efficiency after retrofit. A statement describing the expected configuration and anticipated performance of the HRSG and steam cycle is required.	
B6 (Waste Separation and Disposal)	A statement describing the by-product streams from the capture plant is required. A statement describing the handling / disposal provisions which would be implemented is required. A statement of the estimated amounts of waste products and their proposed method of disposal is required.	Section 6.15
B7 (Cooling Water System)	A statement of the estimated cooling water demands of the capture plant (flows and temperatures) is required. A statement describing how the estimated cooling water demands of the capture plant will be met is required. A statement describing how the cooling water will be supplied to the capture plant is required. The chosen cooling water system should be justified.	Section 6.5
B8 (Compressed Air System)	A statement of the estimated compressed air requirements of the capture plant is required. A statement describing how the estimated compressed air requirements of the capture plant will be met is required.	Section 6.8
B9 (Raw Water Pre-Treatment)	A statement of the estimated raw water pre-treatment requirements of the capture plant (hourly and annual quantities) is required. A statement describing how the estimated raw water pre-treatment requirements of the capture plant will be met is required.	Section 6.9
B10 (Demineralisation / Desalination Plant)	A statement of the estimated demineralised / desalinated water requirements of the capture plant is required. A statement describing how the estimated demineralised / desalinated water requirements of the capture plant will be met is required.	Section 6.10
B11 (Waste Water Treatment Plant)	A statement of the estimated waste water treatment needs of the capture plant is required. A statement describing the expected post-treatment effluent quantity and composition is required.	Section 6.11

Requirement	Description	Reference
	A statement describing the necessary space / other provisions due to the waste water treatment plant is required.	
B12 (Electrical)	A statement of the estimated electrical requirements of the capture plant is required. A statement describing how the estimated electrical requirements of the capture plant will be met is required. This should include the necessary space provisions which will be required.	Section 6.12
B13 (Plant Pipe Racks)	A statement describing the anticipated additional pipe work is required. A statement describing the necessary space / other provisions due to the plant pipe racks is required.	Section 6.16
B14 (Control and Instrumentation)	A statement describing the anticipated additional control and instrumentation equipment is required. A statement describing the necessary space / other provisions due to the additional control and instrumentation equipment is required.	Section 6.17
B15 (Plant Infrastructure)	A statement describing the anticipated additional plant infrastructure (new or widened roads/ extension of office buildings / etc) is required. A statement describing the necessary space / other provisions due to the additional plant infrastructure is required.	Section 6.18
Technical Assessment – CCS Space Key Requirements of Paragraphs 18 to 19 of the CCR Guidance	An outline plot level plan should be provided which is sufficiently detailed to show: The footprint of the power plant; The location of the capture plant; The location of any compression equipment; The location of any chemical storage facilities; and The exit point of the CO_2 pipeline.	Section 5.2 / Figure 3
	Basic calculations, using the estimated volumes of CO_2 which will have to be processed, could usefully be included.	Section 4.3 (Table 4.2)
Technical Assessment – Retrofitting and Integration of CCS	The pre-feasibility level conceptual capture retrofit study should make clear which capture technology is considered most appropriate for retrofit.	Section 4.1 / Section 4.2

Requirement	Description	Reference
Technology Key Requirements of Paragraphs 18 to 19 of the CCR Guidance	The pre-feasibility level conceptual capture retrofit study should provide sufficient detail to demonstrate that there are currently no known technical barriers to subsequent retrofit of capture technology.	Section 6
	The pre-feasibility level conceptual capture retrofit study should take into account the IEA Reference Document (IEA GHG 2007/4 "CO_2 Capture Ready Plants) Advisory Checklists.	Section 6
Technical Assessment – CO_2 Storage Areas Key Requirements of Paragraph 42 of the CCR Guidance	Identify a possible storage area, including delineating the geological extent of that area, and identify within that area at least two oil or gas / gas condensate fields (or saline aquifers) listed in the range of geological formations identified as "viable" or "realistic" in the DTI Study 2006[25] for CO_2 storage.	Section 7 / Figure 6
	Provide a short summary (including an estimate) of the total volume of CO_2 likely to be captured and stored and an estimate of the potential total volume of CO_2 which could be stored in the area.	Section 4.3 (Table 4.2) / Section 7 (Table 7.1 / Table 7.2)
Technical Assessment – CO_2 Transport Key Requirements of Paragraph 61 of the CCR Guidance	Provide sufficient detail to identify the preferred form and route for CO_2 transport on shore from the site exit point to the coastal transition point where the CO_2 goes offshore, including a map sufficiently large for the proposed route corridor to be clear.	Section 8.2 / Figure 7 / Figure 8
	Provide sufficient detail to identify the preferred form and route for CO_2 transport off shore from the coastal transition point to the identified CO_2 storage area, including a map sufficiently large for the proposed route corridor to be clear.	Section 8.3 / Figure 6
	Demonstrate and confirm that there are no known barriers or unavoidable safety obstacles which exist within the identified on shore and off shore route corridors on the basis of current knowledge on CO_2 transport.	Section 8.4
	Suggest methods by which the environmental impacts on any unavoidable designated sites within the route corridor could be mitigated.	Section 8.4

[25]*DTI Study 2006 "Industrial Carbon Dioxide Emissions and Carbon Dioxide Storage Potential in the UK" Report No. COAL R308 DTI/Pub URN 06/2027 (October 2006).*

Table B2 – Carbon Capture and Storage Requirements for a IGCC Power Plant with Pre-Combustion CO2

Requirement	Description	Reference
C1 (Design, Planning Permissions and Approvals)	A feasibility-level Design Concept Report (DCR) for the power plant with carbon dioxide (CO_2) capture should be supplied for assessment showing how the proposed pre-combustion capture plant is technically feasible.	This Document
	A preliminary plot plan for the plant retrofitted with capture should be provided.	Section 5.2 / Figure 3
	A list of consents and licences required for successful implementation of the Project should be provided.	Section 3.7 (Table 3.1)
	A Project Programme (outlining the anticipated dates of Front End Engineering Design (FEED), Engineering Procurement Construction (EPC), commissioning and commercial operation) should be provided.	Section 3.8 (Insert 3.1)
	The findings of the Environmental Statement should be summarised and details of the main environmental impacts due to the Power Plant with CCS should be provided.	Non-Technical Summary of the ES
C2 (Power Plant Location)	A description of the proposed site location and ownership is required.	Section 3.3
	A description of the geotechnical conditions of the site and any known contamination should be provided. In addition, a description of any site preparation which will be required (including details at site drainage, foundation design and building design) should be provided.	Section 3.4 / Section 3.6
	Details of site access during construction and operation should be provided.	Section 3.5
	The exit point of any emission and effluent streams from the cartilage of the capture plant should be provided. A discussion on how this affects the	Section 5.2 / Figure 3

Requirement	Description	Reference
	configuration of the capture plant should be provided.	
C3 (Space Requirements and Preliminary Plot Plan)	A preliminary plot plan is required clearly identifying unit block sizes for the coal storage and preparation, coal gasification, CO shift, cooling and condensation, ASU, CO_2 capture, solvent regeneration, sulphur recovery, compression, dehydration (if required), associated utilities (including vent stack) and storage equipment. The HRSG and fuel gas conditioning system should also be indicated.	Section 5.2 / Figure 3
	The unit block sizes should be engineered to suit the facility's capacity, operating conditions, construction and maintenance requirements and storage requirements.	Section 4.3 / Section 5.2 / Figure 3
	The preliminary plot plan should identify how the power plant and capture plant are integrated.	Section 5.2 / Figure 3
C4: Process Overview of Capture Plant	C4.1: Capture Process A process overview is required. This should include, but is not limited to:	
	Expected configuration and anticipated performance of the coal preparation, coal gasification, CO shift, cooling and condensation, ASU, CO_2 capture, solvent regeneration and sulphur recovery equipment.	Section 4.3 / Section 5.2 / Figure 3
	Reasons for the selection of pre-combustion capture and for chosen capture technology.	Section 4.1 / Section 4.2
	The product specifications including a typical fuel gas composition (in particular the concentration of hydrogen) to the gas turbine from the capture plant.	Section 4.4
	A statement concerning the range of acceptable fuel compositions to the gas turbine and their corresponding impact on gas turbine performance.	Section 4.4
	Where flue gas conditioning is	Section 4.5

Requirement	Description	Reference
	required (e.g. selective catalytic reduction equipment to further reduce NO_x), details should be provided.	
	Where heat and / or power are to be provided from the power plant, a description of the integration between the power plant and the capture process is required. If this is not the case, this should be justified and a description of the heat and / or power source should be provided.	Section 4.6
	A discussion of the impacts of the scale up of the capture technology (where the capture technology has not yet been implemented at this scale) in the proposed design. This should include a description of where the scale-up involves a change in design, construction methods or materials, and should focus on the main risks that this presents and how these risks are to be mitigated.	Section 4.9
	A statement describing how it will be determined that the amount of CO_2 being captured complies with the 300 MW net requirement.	Section 4.9
	C4.2: Compression and Dehydration Unit A process overview is required. This should include, but is not limited to:	
	Expected configuration and anticipated performance of the compression and dehydration units (if required).	Section 43 / Section 5.2 / Figure 3
	Product specification, including predicted water content, phase and purity of CO_2	Section 4.3 / Section 4.4
	Expected amount of captured CO_2 to be compressed, dehydrated and sent to storage.	Section 4.3
C5: Overview of Utility Requirements	C5.1 (Heat Recovery Steam Generator (HRSG) and Plant Steam Cycle)	
	The HRSG must be designed to accommodate the changed flue gas composition and temperatures after pre-combustion capture retrofit. The steam cycle as a whole must also	Section 6.2

Requirement	Description	Reference
	be designed to accommodate the needs of the hydrogen production facility to allow for reasonable thermal integration and hence overall plant efficiency after retrofit. A statement describing the expected configuration and anticipated performance of the HRSG and steam cycle is required.	
	C5.2 (Water-Steam-Condensate Cycle)	
	A statement describing the arrangements to be made to facilitate low grade heat recovered from the capture / compression equipment to be used in the water-steam-condensate cycle is required. Where potentially useful options have not been facilitated, these should be justified.	Section 6.4
	C5.3 (Fuel Gas Conditioning System)	
	A statement describing the expected configuration and anticipated performance of the fuel gas conditioning system is required.	Section 6.5
	C5.4 (Cooling Water System)	
	A statement of the estimated cooling water demands of the capture plant (flows and temperatures) is required. A statement describing how the estimated cooling water demands of the capture plant will be met is required. A statement describing how the cooling water will be supplied to the capture plant is required. The chosen cooling water system should be justified.	Section 6.7
	C5.5 (Compressed Air System)	
	A statement of the estimated compressed air requirements of the capture plant is required. A statement describing how the estimated compressed air requirements of the capture plant will	Section 6.8

Requirement	Description	Reference
	be met is required.	
	C5.6 (Raw Water Pre-Treatment)	
	A statement of the estimated raw water pre-treatment requirements of the capture plant (hourly and annual quantities) is required. A statement describing how the estimated raw water pre-treatment requirements of the capture plant will be met is required.	Section 6.9
	C5.7 (Demineralisation / Desalination Plant)	
	A statement of the estimated demineralised / desalinated water requirements of the capture plant is required. A statement describing how the estimated demineralised / desalinated water requirements of the capture plant will be met is required.	Section 6.10
	C5.8 (Waste Water Treatment Plant)	
	A statement of the estimated waste water treatment needs of the capture plant is required. A statement describing the expected posttreatment effluent quantity and composition is required. A statement describing the necessary space / other provisions due to the waste water treatment plant is required.	Section 6.11
	C5.9 (Electrical)	
	A statement of the estimated electrical requirements of the capture plant is required. A statement describing how the estimated electrical requirements of the capture plant will be met is required. This should include the necessary space provisions which will be required.	Section 6.12
	C5.10 (Nitrogen System)	

Requirement	Description	Reference
	A statement of the estimated nitrogen requirements of the capture plant is required. A statement describing how the estimated nitrogen requirements of the capture plant will be met is required. This should include the necessary space / other provisions due to the nitrogen requirements.	Section 6.13
	C5.11 (Chemical Dosing Systems)	
	A statement of the estimated chemical injection requirements of the capture plant is required. A statement describing how the estimated chemical injection requirements of the capture plant will be met is required.	Section 6.14
	C5.12 (Waste Separation and Disposal)	
	A statement describing the by-product streams from the capture plant is required. A statement describing the handling / disposal provisions which would be implemented is required. A statement of the estimated amounts of waste products and their proposed method of disposal is required.	Section 6.15
C6: Block Flow Diagram of Capture Plant	A block flow diagram of the capture plant is required and should include: Coal preparation, coal gasification, CO shift, cooling and condensation, ASU, CO_2 capture, solvent regeneration and sulphur recovery equipment; Associated site storage for capture plant operation; CO_2 compression and dehydration (if required); Associated utilities including HRSG and fuel gas conditioning systems; and, Power plant, clearly indicating where CO_2 is extracted from and where any integration occurs between the power	Section 4.7 (Insert 4.1 / Insert 4.2)

Requirement	Description	Reference
	plant and capture plant.	
C7: Heat and Material Balance of Capture Plant	A heat and material balance should be provided for the block flow diagram foe maximum / rated CO_2 flow through the capture process. For each stream identified on the block flow diagram, the following information is expected: Fluid description; Mass and / or volumetric flow rate; Phase; Temperature; and Pressure.	Section 4.8 (Insert 4.3)
C8 (Interfaces)	An interface register is required detailing: The key interfaces between the sub-systems and sections of the capture plant; The key interfaces between the sub-systems and sections of the capture plant and the power plant; and The key interfaces with services such as electricity, water, gas and other utilities	Section 4.6 (Table 4.8 / Table 4.9)
C9: Full Scale Carbon Capture	A statement is required describing the upgrade from 300 MW net to full capacity of the Power Plant. Consideration should be given to space requirements, utility and storage requirements.	Section 4.9

Table B3 – Carbon Capture Readiness (CCR) Requirements Checklist for a CCGT Power Plant with Post-Combustion CO2 Capture

Requirement	**Description**	**Reference**
C1 (Design, Planning Permissions and Approvals)	A pre-feasibility level conceptual capture retrofit study should be supplied for assessment showing how the proposed features would make adding post-combustion capture to the power plant technically feasible.	Section 6
	An outline plot level plan for the power plant retrofitted with CO_2 capture should be provided.	Figure 10
C2 (Power Plant	The work undertaken on the CO_2 transport and storage	Section 7 / Section 8

Requirement	Description	Reference
Location)	should be referenced.	
	The exit point of gases from the curtilage of the power / CO_2 capture plant should be provided. A statement on how this affects the configuration of the power / CO_2 capture plant should be provided.	Section 8
C3 (Space Requirements)	The CCR Guidance states that "*space will be required for the following:* *CO_2 capture equipment, including any flue gas pre-treatment and CO_2 drying and compression;* *Space for routing flue gas duct to the CO_2 capture equipment;* *Steam turbine island additions and modifications (e.g. space in steam turbine building for routing large low pressure steam pipe to amine scrubber unit);* *Extension and addition of balance of plant systems to cater for the additional requirements of the capture equipment;* *Additional vehicle movements (amine transport, etc.); and,* *Space allocation for storage and handling of amines and handling of CO_2 including space for infrastructure to transport CO_2 to the plant boundary."*	N / A
	All of the provisions of a) to f) should be implemented. A statement describing how the space allocations were determined and how they will be met is required.	Section 5 / Figure 10
C4 (Gas Turbine Operation with Increased Exhaust Pressure)	The CCR Guidance states that *"the gas turbine (and upstream ducting and heat recovery steam generator (HRSG)) must be able to operate with the increased back pressure imposed by the capture equipment, or alternatively space must be provided for a booster fan."*	N / A
	A statement giving the expected pressure drop required for current commercial capture equipment (together with a manufacturer's confirmation that the gas turbine can accommodate this) is required. In addition, for the expected pressure drop, a statement giving the anticipated effects on performance is required. Alternatively, a statement on the expected booster fan specification (and any associated space / installation requirements) is required.	Section 6.6

Requirement	Description	Reference
C5 (Flue Gas System)	The CCR Guidance states that *"space should be available for installing new duct work to enable interconnection of the existing flue gas system with the amine scrubbing plant and provisions in the duct work for tie-ins and addition of items, such as bypass dampers and isolation dampers, will be required as a minimum. If selective catalytic reduction (SCR) or other flue gas treatment is likely to be added at the time of retrofit then space for this should also be provided."*	N / A
	A statement describing the space and required flue gas system configuration (and how they would be implemented) is required.	Section 6
C6 (Steam Cycle)	A statement giving the steam pressure at the steam turbine IP / LP crossover (or other steam extraction point) is required. A statement on any post-retrofit equipment modifications / additions is required. A statement demonstrating that the steam cycle could be operated with capture using solvent systems with a range of steam requirements is required. A statement estimating the energy penalty involved in steam extraction is required. A statement estimating the energy penalty involved in steam extraction (from a purpose built steam cycle) is required.	Section 6
C7 (Cooling Water System)	The CCR Guidance states *"the amine scrubber, flue gas cooler and CO_2 compression plant introduced for CO_2 capture increase the overall power plant cooling duty."*	N / A
	A statement of the estimated cooling water demands of the CO_2 capture plant (flows and temperatures) is required. A statement describing how the estimated cooling water demands of the CO_2 capture plant will be met is required. A statement describing how the cooling water will be supplied to the CO_2 capture plant is required. The chosen cooling water system should be justified.	Section 6
C8 (Compressed Air System)	The CCR Guidance states that *"the capture equipment addition will call for additional compressed air (both service and instrument air) requirements".*	N / A
	A statement of the estimated compressed air	Section 6

Requirement	Description	Reference
	requirements of the CO_2 capture plant is required. A statement describing how the estimated compressed air requirements of the CO_2 capture plant will be met is required.	
C9 (Raw Water Pre-Treatment Plant)	The CCR Guidance states that *"space shall be considered in the raw water pre-treatment plant area to add additional raw water pre-treatment streams as required".*	N / A
	A statement of the estimated raw water pre-treatment requirements of the CO_2 capture plant is required. A statement describing how the estimated raw water pre-treatment requirements of the CO_2 capture plant will be met is required.	Section 6
C10 (Demineralisation / Desalination Plant)	The CCR Guidance states that *"a supply of reasonably pure water may be required to make up evaporative losses from the flue gas cooler and / or scrubber. Estimates of this water requirement should be made and space allocated for the necessary treatment plant (and an additional water source be identified if necessary".*	N / A
	A statement of the estimated demineralised / desalinated water requirements of the CO_2 capture plant is required. A statement describing how the estimated demineralised / desalinated water requirements of the capture plant will be met is required.	Section 6
C11 (Waste Water Treatment Plant)	The CCR Guidance states that *"amine scrubbing plant along with flue gas coolers (if appropriate) provided for post-combustion CO_2 capture will result in generation of additional effluents".*	N / A
	A statement of the estimated waste water treatment needs of the CO_2 capture plant is required. A statement describing the expected post-treatment effluent quantity and composition is required. A statement describing the necessary space / other provisions due to the waste water treatment plant is required.	Section 6
C12 (Electrical)	The CCR Guidance states that *"the introduction of amine scrubber plant along with flue gas coolers, booster fans (if required), and CO_2 compression plant will lead to a number of additional electrical loads (e.g. pumps,*	N / A

Requirement	Description	Reference
	compressors)".	
	A statement of the estimated electrical requirements of the CO_2 capture plant is required. A statement describing how the estimated electrical requirements of the CO_2 capture plant will be met is required. This should include the necessary space provisions which will be required.	Section 6
C13 (Plant Pipe Racks)	The CCR Guidance states that *"installation of additional pipework after retrofit with carbon 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, additional cooling water piping and possibly other plant modifications."*	N / A
	A statement describing the anticipated additional pipe work is required. A statement describing the necessary space / other provisions due to the plant pipe racks is required.	Section 6
C14 (Control and Instrumentation)	A statement describing the anticipated additional control and instrumentation equipment is required. A statement describing the necessary space / other provisions due to the additional control and instrumentation equipment is required.	Section 6
C15 (Plant Infrastructure)	The CCR Guidance states that *"space 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 buildings are foreseeable. Consideration should also be given as to how, during a retrofit, vehicles and cranes will access the areas where new equipment will need to be erected".*	N / A
	A statement describing the anticipated additional plant infrastructure (new or widened roads/ extension of office buildings / etc.) is required. A statement describing the necessary space / other provisions due to the additional plant infrastructure is required.	Section 6
Technical Assessment – Space	An outline plot level plan should be provided which is sufficiently detailed to show: • The footprint of the power plant;	Figure 10

Requirement	Description	Reference
Key Requirements of Paragraphs 18 to 19 of the CCR Guidance	• The location of the capture plant; • The location of any compression equipment; • The location of any chemical storage facilities; and • The exit point of the CO_2 pipeline.	
	Basic calculations, using the estimated volumes of CO_2 which will have to be processed, could usefully be included.	Section 4
Technical Assessment – Retrofitting and Integration **Key Requirements of Paragraphs 30 to 31 of the CCR Guidance**	The pre-feasibility level conceptual capture retrofit study should make clear which capture technology is considered most appropriate for retrofit.	Section 4
	The pre-feasibility level conceptual capture retrofit study should provide sufficient detail to demonstrate that there are currently no known technical barriers to subsequent retrofit of capture technology.	Section 6
	The pre-feasibility level conceptual capture retrofit study should take into account the IEA Reference Document (IEA GHG 2007/4 "CO_2 Capture Ready Plants) Advisory Checklists.	Section 6
Technical Assessment – CO_2 Storage Areas **Key Requirements of Paragraph 42 of the CCR Guidance**	Identify a possible storage area, including delineating the geological extent of that area, and identify within that area at least two oil or gas / gas condensate fields (or saline aquifers) listed in the range of geological formations identified as "viable" or "realistic" in the DTI Study 2006 (Ref. Appendix 3.1) for CO_2 storage.	Section 7
	Provide a short summary (including an estimate) of the total volume of CO_2 likely to be captured and stored and an estimate of the potential total volume of CO_2 which could be stored in the area.	Section 7
Technical Assessment – CO_2 Transport **Key Requirements of Paragraph 61 of the CCR Guidance**	Provide sufficient detail to identify the preferred form and route for CO_2 transport onshore from the site exit point to the coastal transition point where the CO_2 goes offshore, including a map sufficiently large for the proposed route corridor to be clear.	Section 8
	Provide sufficient detail to identify the preferred form and route for CO_2 transport offshore from the coastal transition point to the identified CO_2 storage area, including a map sufficiently large for the proposed route corridor to be clear.	Section 8

Requirement	Description	Reference
	Demonstrate and confirm that there are no known barriers or unavoidable safety obstacles which exist within the identified onshore and offshore route corridors on the basis of current knowledge on CO_2 transport.	Section 8
	Suggest methods by which the environmental impacts on any unavoidable designated sites within the route corridor could be mitigated.	Section 8

APPENDIX C – ANNEX B OF CARBON CAPTURE READINESS (CCR) GUIDANCE (NOVEMBER 2009) –

"Environment Agency Verification of CCS Readiness New Natural Gas Combined Cycle Power Station Using Pre-Combustion CO2 Capture (including coal gasification) and Hydrogen-Rich Fuel Gas Combustion"

Annex B

Environment Agency Verification of CCS Readiness New Natural Gas Combined Cycle Power Station Using Pre-Combustion CO_2 Capture (including coal gasification) and Hydrogen-Rich Fuel Gas Combustion

Capture Ready Features

See IEA GHG Technical Reports 2007/4 "CO_2 Capture Ready Plants" and 2005/1 'Retrofit of CO_2 Capture to Natural Gas Combined Cycle Power Plants' as background to this document.

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.

Pre-combustion (on site, gas and/or coal fuel)

The expectation is that it would be sufficient for a new natural gas combined cycle power plant to be capture-ready for post-combustion capture. The plant developer might alternatively choose to make the plant capture-ready for pre-combustion capture on-site, but would need to show that there is a reasonable expectation that this would offer an equally effective option for retrofitting capture in the future.

Pre-combustion capture involves the conversion of natural gas or coal to a hydrogen-rich fuel gas with the capture of the CO_2 produced during this process (or conversion of other fuels such as petroleum coke, petroleum residues, natural bitumens etc that can beneficially be upgraded through gasification; where "coal" is written in this checklist it can be extended to include such fuels). The hydrogen-rich fuel gas is then burnt in the gas turbine, replacing natural gas.

The general procedure is conversion of the fuel to a syngas consisting mainly of CO and H_2 by reforming (probably autothermal reforming for natural gas) or gasification (for other fuels), followed by a shift process in which the CO in the syngas is reacted with H_2O to form CO_2 and more H_2. The CO_2 is then removed for compression (including drying and, possibly, some removal of impurities) followed by transport to storage or use. Either air or oxygen (plus some steam) could be used for the autothermal reforming and the gasification stages, but based on current experience it is more likely that air would be used for the former and oxygen for the latter.

B1 Design, Planning Permissions and Approvals

Note B1: A pre-feasibility-level conceptual capture retrofit study should be supplied for assessment, showing how the proposed CCR features would make adding pre-combustion capture technically feasible,

together with an outline level plot plan for the plant retrofitted with capture. If the plant is not also going to be capture-ready for post-combustion capture then the justification for this should be provided.

B2 Power Plant Location

Note B2a: The work undertaken on CO_2 transport and storage should be referenced; the exit point of gases from the curtilage of the plant and how this affects the configuration of the capture equipment is the important aspect for the Environment Agency.

Note B2b: Health and Safety items in this section are outside the Environment Agency remit.

B3 Space Requirements

Space will be required for the following:

a) *If appropriate, coal delivery and storage facilities (and additional evidence will be provided to show that coal transport to the site is feasible);*
b) *Hydrogen fuel gas production facilities, including fuel reforming or gasification equipment, shift reactor, CO_2 separation and compression equipment and all other gas purification (including sulphur removal) or other pre-treatment facilities.*
c) *If appropriate, an air separation unit for oxygen production (plus possibly space for oxygen storage), with necessary separations from other equipment and space for the necessary oxygen pipelines.*
d) *Space for piping hydrogen-rich fuel gas to the gas turbine, and for gas compression equipment if required.*
e) *Steam turbine island additions and modifications (e.g. space in the steam turbine building for supplying and receiving steam to/from the hydrogen production facilities).*
f) *Extension and addition of balance of plant systems to cater for the additional requirements of the capture equipment, including CO_2 pipeline (and/or other facilities for CO_2 transport).*
g) *Additional vehicle movements.*
h) *Space allocation considering storage and handling of hydrogen, oxygen if appropriate and of CO_2.*

Note B3: It is expected that all of the provisions in a-h above will be implemented, including the provision of space and access to carry out the necessary works at the time of retrofitting without excessive interruptions to normal plant operation. A statement describing how the space allocations were determined and how they will be met is required. Further details are requested in the following sections as appropriate.

B4 Gas Turbine Combined Cycle unit operation with hydrogen-rich fuel gas

The gas turbine must be able to be modified to operate with the proposed hydrogen-rich fuel gas (including achieving any likely environmental *restrictions on the emissions of NOx, possibly with the addition of selective catalytic reduction equipment - SCR).*

Note B4: A statement is required confirming that it will be possible to modify the gas turbine to accommodate firing on hydrogen-rich fuel gas in the future and estimating the future performance.

B5 Heat recovery steam generator, HRSG, and plant steam cycle

The heat recovery steam generator must be designed to accommodate the changed flue gas composition and temperatures after pre-combustion capture retrofit. The steam cycle as a whole must also be designed to accommodate the needs of the hydrogen production facility, both for providing any additional steam supplies to that facility and for the use of any additional steam production in the hydrogen production facility, to allow reasonable thermal integration and hence overall plant efficiency after retrofit.

Note B5: A statement is required describing changes in the requirements for the HRSG and steam cycle after retrofit and how they will be modified to accommodate this.

B6 Waste Separation and Disposal Facilities

Gasification of certain fuels such as coal or petroleum coke will give rise to by-product residue streams such as sulphur and/or solid ash that do not occur on natural gas plants. Provision for handling such streams on-site and for their satisfactory disposal from the site must be identified.

Note B6: A statement is required identifying any additional by-product streams from the plant after pre-combustion capture is retrofitted and describing the appropriate handling and disposal provisions that would be implemented.

B7 Cooling Water System

Pre-combustion CO_2 capture will increase the overall power plant cooling duty.

Note B7: A statement is required of estimated cooling water requirements (flows and temperatures) and how these will be met. It is expected that necessary space and tie-ins for additional cooling water supplies to the plant after retrofitting pre-combustion capture will be provided and a description of these is required.

B8 Compressed Air System

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

Note B8: A statement is required of estimated additional compressed air requirements together with a description of how these will be accommodated.

B9 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 B9: A statement is required of estimated treated raw water requirements together with a description of how these will be accommodated.

B10 Demineralisation / Desalination Plant

Additional supplies of demineralised water are likely to be required after retrofitting e.g. for process steam used in the hydrogen production facility and possibly in the gas turbine NOx control system. Estimates of any such water requirements should be made and space allocated for the necessary treatment plant (and an additional water source be identified if necessary).

Note B10: A statement is required saying which of the above are needed and in what quantity and also describing how the necessary provisions will be implemented.

B11 Waste Water Treatment Plant

Fuel processing for pre-combustion CO_2 capture is expected to result in generation of additional waste water effluents.

Note B11: A statement is required giving estimated additional waste water treatment needs and describing how the necessary space and any other provisions will be provided to meet expected demands.

B12 Electrical

The introduction of the hydrogen production facility with pre-combustion capture will lead to a number of additional electrical loads (e.g. pumps, compressors).

Note B12: A statement is required listing the estimated additional electrical requirements and describing space allocation in suitable locations for items such as additional transformers, switching gear and cabling.

B13 Plant Pipe Racks

Installation of additional pipework after retrofit with capture will be required, e.g. for gas and steam transport and additional cooling water piping and possibly other plant modifications.

Note B13: It is expected that provision will be made for space for routing new pipework at the appropriate locations. A statement identifying anticipated significant additional pipework and describing space allocations to accommodate these is required.

B14 Control and Instrumentation

Note B14: It is expected that space and provisions for additional control equipment and cabling will be implemented. A statement identifying anticipated additional control equipment and describing space and other provisions to accommodate these is required.

B15 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. Consideration should also be given to how, during a retrofit, vehicles or cranes will access the areas where new equipment will need to be erected.

Note B15: It is expected that the provisions above will be implemented. A statement identifying anticipated requirements and describing how they will be met is required.

APPENDIX D – ANNEX C OF THE DRAFT SUPPLEMENTARY GUIDANCE –

"(Environment Agency Verification of CCS Technical Feasibility: New Integrated Gasification Combined Cycle Power Station using Pre-Combustion CO2 Capture (Coal Gasification) and Hydrogen-Rich Fuel Gas Combustion)"

Annex C: Environment Agency verification of ccs technical feasibility: new integrated gasification combined cycle power station using pre-combustion co2 capture (coal gasification) and hydrogen-rich fuel gas combustion

C1: Design, Planning Permissions and Approvals

A feasibility-level Design Concept Report (DCR) for the Power Plant with carbon dioxide (CO2) capture should be supplied for assessment, showing how the proposed pre-combustion capture plant is technically feasible. The DCR should include a preliminary plot plan (as detailed in section C3).

The DCR should also provide details of the list of consents and licenses required for successful implementation of the Project, in addition to a Project Programme outlining the anticipated dates of Front End Engineering Design (FEED), Engineering Procurement Construction (EPC), commissioning and commercial operation.

The findings of the Environmental Statement (ES) should be summarised and details of the main environmental impacts due to the Power Plant with CCS should be provided.

C2: Power Plant Location

A description of the proposed site location and ownership is required.

This should include details on the geotechnical conditions of the site (referencing any geotechnical studies where appropriate) and any known contamination, in addition to providing details on the proposed site access during construction and operation.

Additionally, this should provide details on the necessary site preparation which will be required, including details of site drainage, foundation design and building design.

The exit point of any emission and effluent stream from the curtilage of the plant and how this affects the configuration of the capture equipment is the important aspect for the Environment Agency.

Health and Safety items in this section are outside the Environment Agency remit.

C3: Space Requirements and Preliminary Plot Plan

A preliminary Plot Plan is required clearly identifying unit block sizes for the coal storage and preparation, coal gasification, CO shift, cooling and condensation, Air Separation Unit (ASU) (if applicable), CO2 capture, solvent regeneration, sulphur recovery, compression, dehydration (if required), associated utilities (including vent stack), and storage equipment. Heat Recovery Steam Generator (HRSG) and fuel gas conditioning systems should also be indicated.

The Plot Plan should identify how the Capture Plant integrates with the Power Plant.

The Plot Plan should identify unit block sizes for the Power Plant including size and number of generators.

The unit block sizes and spacing should be engineered to suit the facility's capacity, operating conditions, construction and maintenance philosophies and storage requirements.

The following features are identified as being critical to the layout of the capture plant:

- Relative location of units and equipment to satisfy process pipe work requirements and minimise lengths of large diameter lines;
- Location and orientation of air-coolers, cooling towers, effluent treatment, buildings and the vent stack to take account of the direction of the prevailing wind;
- The Administration Area (main office building, laboratory, workshop and maintenance buildings) should be arranged in a comparatively clean area to avoid dust from other process units and should be located away from the coal gasification units, capture process and from high pressure CO_2.

Applicants should be prepared to submit plans and supporting documents to demonstrate that sufficient space is available to accommodate carbon capture equipment (sized so as to be capable of processing emissions from entire power station). Requirements are defined in Guidance on Carbon Capture Readiness for Section 36 Electricity Act 1989 Consents Application.

C4: Process Overview of Capture Plant

A process description of the overall Capture Plant is required. This should include, but is not limited to:

C4.1: Capture Process

An overview of the Capture Plant including coal preparation, coal gasification, CO shift, cooling and condensation, ASU (if applicable), capture of CO_2, regeneration of solvent, sulphur recovery and any associated storage requirements. This overview should include the following:

- Expected configuration and anticipated performance of the coal preparation, coal gasification, CO shift, cooling and condensation, ASU, CO_2 capture, solvent regeneration and sulphur recovery equipment;
- Reasons for selection of pre-combustion capture and for chosen capture technology;
- The product specifications including a typical fuel gas composition (in particular the concentration of hydrogen) to the gas turbine from the Capture Plant;
- A statement concerning the range of acceptable fuel gas compositions to the gas turbine and their corresponding impact on gas turbine performance;
- Where flue gas conditioning is required (e.g. selective catalytic reduction equipment to further reduce NOx), details should be provided;

- Where heat and / or power are to be provided from the Power Plant, a description of the integration between the Power Plant and the capture process is required. If this is not the case, this should be justified and a description or the source provided;
- A discussion of the impacts of the scale-up of the capture technology (where capture technology has not yet been implemented at this scale) in the proposed design. This should include a description of where the scale-up involves a change in design, construction methods or materials and should focus on the main risks that this presents and how these risks are to be mitigated;
- A statement describing how it will be determined that the amount of CO_2 being capture complies with the 300MW (net) requirement.

C4.2: Compression and Dehydration Unit

An overview of the Compression and Dehydration (if required) unit is required and should include:

- Expected configuration and anticipated performance of the compression and dehydration (if required) units is required.
- Product specifications including predicted water content, phase and purity of the CO_2 stream to be stored
- A statement describing how much of the captured CO_2 will be compressed, dehydrated (if required) and sent to storage.

C5: Overview of Utility Requirements

A description of overall Utility Requirements is required. This should include, but is not limited to:

C5.1: Heat Recovery Steam Generator (HRSG) and Plant Steam Cycle

A statement is required describing the expected configuration and anticipated performance of the HRSG and plant steam cycle. Details should be provided concerning how the plant steam cycle is designed to accommodate the needs of the hydrogen production facility, both for providing any additional steam supplies to that facility and for the use of any additional steam production in the hydrogen production facility to allow reasonable thermal integration and hence overall plant efficiency.

C5.2: Water - Steam - Condensate Cycle

Description of the arrangements made to facilitate low grade heat recovered from the capture and compression equipment being used in the water-steam-condensate cycle. Where potentially-useful options have not been facilitated this should be justified.

C5.3: Fuel gas conditioning system

A statement is required describing the expected configuration and anticipated performance of the fuel gas conditioning system.

C5.4: Cooling Water System

A statement is required of estimated cooling water demands (flows and temperatures) of the Capture Plant and how these will be met. A description of how cooling water will be supplied to the Capture Plant should be included.

Cooling systems (including once through cooling, cooling towers and air cooling) should be discussed and the proposed selection justified.

C5.5: Compressed Air System

A statement is required of estimated compressed air requirements to the Capture Plant together with a description of how these will be accommodated.

C5.6: Raw Water Pre-treatment Plant

A statement is required of estimated treated raw water requirements (hourly and annual quantities) from the Capture Plant together with a description of how these will be accommodated.

C5.7: Demineralisation I Desalination Plant

A statement is required of estimated demineralised water requirements during start-up and during normal operation of the Capture Plant and how these will be accommodated.

C5.8: Waste Water Treatment Plant

A statement is required giving estimated waste water treatment needs and stating how the necessary space and any other provisions will be provided to meet expected demands of the Capture Plant. Expected post-treatment effluent quantity and composition should be discussed.

C5.9: Electrical

A statement is required listing the estimated electrical requirements and describing space allocation in suitable locations for items such as transformers, switching gear and cabling.

C5.10: Nitrogen System

A statement is required giving estimated nitrogen requirements and stating how the necessary space and any other provisions will be provided to meet expected demands of the Capture Plant.

C5.11: Chemical Dosing Systems

A statement is required listing the estimated Capture Plant chemical injection requirements and describing how these will be accommodated.

C5.12: Waste Separation and Disposal Facilities

A statement is required identifying by-product streams from the Capture Plant and describing the appropriate handling and disposal provisions that would be implemented.
The estimated amounts of waste products produced and the proposed method of disposal (e.g. sulphur).

C6: Block Flow Diagram of Capture Plant

A Block Flow Diagram of the Capture Plant is required and should include:

- Coal preparation, coal gasification, CO shift, cooling and condensation, ASU, CO_2 capture, solvent regeneration and sulphur recovery equipment;
- Associated on site storage for capture plant operation;
- CO2 compression and dehydration (if required);
- Associated utilities including HRSG and fuel gas conditioning systems;
- Power Plant clearly indicating where CO2 is extracted from and where any integration occurs between the Power and Capture Plant i.e. heat and / or power.

C7: Heat & Material Balance of Capture Plant

A heat and material balance should be provided for the Block Flow Diagram for maximum / rated CO_2 flow rate through the Capture process.

For each stream number identified on the Block Flow Diagram, the following information is expected:

- Fluid description
- Mass and / or volumetric flow rate
- Phase
- Temperature
- Pressure

C8: Interfaces

An interface register detailing the key interfaces between sub-systems and sections within the Capture Plant should be provided. The interface register should also detail the key interfaces between the sub-systems and sections of the Capture Plant with the Power Plant.
The register should be supported with high level illustrative diagrams where necessary.
This should also include interfaces with systems such as electricity, water, gas connections and other utilities as required.

C9: Full Scale Carbon Capture

A statement is required describing the upgrade from 300MW (net) to full capacity of the Power Plant. Consideration should be given to space requirements, utility and storage requirements.

APPENDIX E - ANNEX C OF CARBON CAPTURE READINESS (CCR) GUIDANCE (NOVEMBER 2009) –

"Environment Agency verification of CCS Readiness New Natural Gas Combined Cycle Power Station Using Post-Combustion Solvent Scrubbing"

Annex C

Environment Agency verification of CCS Readiness New Natural Gas Combined Cycle Power Station Using Post-Combustion Solvent Scrubbing

Capture Ready Features

Relevant text from IEA GHG Technical Report 2007/4 "CO_2 Capture Ready Plants" is used as a basis for the requirements in this list. See also IEA GHG report 2005/1 'Retrofit of CO_2 Capture to Natural Gas Combined Cycle Power Plants'.

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.

Post-combustion (amine scrubbing)

C1 Design, Planning Permissions and Approvals

Note C1: A pre-feasibility-level conceptual capture retrofit study should be supplied for assessment, showing how the proposed CCR features would make adding post-combustion capture technically feasible, together with an outline level plot plan for the plant retrofitted with capture.

C2 Power Plant Location

Note C2a: The work undertaken on CO_2 transport and storage should be referenced; the exit point of gases from the curtilage of the plant and how this affects the configuration of the capture equipment is the important aspect for the Environment Agency.

Note C2b: Health and Safety items in this section are outside the Environment Agency remit.

C3 Space Requirements

Space will be required for the following:

a) *CO_2 capture equipment, including any flue gas pretreatment and CO_2 drying and compression.*
b) *Space for routing flue gas duct to the CO_2 capture equipment.*
c) *Steam turbine island additions and modifications (e.g. space in steam turbine building for routing large low pressure steam pipe to amine scrubber unit).*
d) *Extension and addition of balance of plant systems to cater for the additional requirements of the capture equipment.*
e) *Additional vehicle movement (amine transport etc).*

f) *Space allocation for storage and handling of amines and handling of CO_2 including space for infrastructure to transport CO_2 to the plant boundary.*

Note C3: It is expected that all of the provisions in a-f above will be implemented, including the provision of space and access to carry out the necessary works at the time of retrofitting without excessive interruptions to normal plant operation. A statement describing how the space allocations were determined and how they will be met is required. Further details are requested in the following sections as appropriate. The space for capture equipment might be significantly reduced if flue gas recycling through the gas turbine is used to concentrate the CO_2, but to validate this option suitable demonstrations of its feasibility by the gas turbine supplier would be required.

C4 Gas Turbine Operation with Increased Exhaust Pressure

The gas turbine (and upstream ducting and heat recovery steam generator, HRSG) must be able to operate with the increased back pressure imposed by the capture equipment, or alternatively space must be provided for a booster fan.

Note C4: A statement is required giving the expected pressure drop required for current commercial capture equipment together with a manufacturer's confirmation that the gas turbine can accommodate this and any effects on the performance, or alternatively describing booster fan specification together with space and other installation requirements.

C5 Flue Gas System

Space should be available for installing new duct work to enable interconnection of the existing flue gas system with the amine scrubbing plant and provisions in the duct work for tie-ins and addition of items such as bypass dampers and isolation dampers will be required as a minimum. If selective catalytic reduction (SCR) or other flue gas treatment is likely to be added at the time of retrofit then space for this should also be provided.

Note C5: A statement is required describing the space and required flue gas system configuration for retrofit requirements and how they will be implemented.

C6 Steam Cycle

Note C6: A statement is required giving the steam pressure at the steam turbine IP/LP crossover (or other steam extraction point), together with a description of any post-retrofit equipment modifications/additions. It should be demonstrated that the steam cycle could be operated with capture using solvent systems with a range of steam requirements. The energy penalty involved in such steam extraction should be estimated and compared to theoretical minimum values (i.e. for extraction from a similar steam cycle that has been purpose-built for such steam extraction).

C7 Cooling Water System

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

Note C7: A statement is required of estimated cooling water demands (flows and temperatures) with capture and how these will be met. It is expected that necessary space and tie-ins for cooling water supplies to post-combustion capture equipment will be provided and a description of these should be included.

C8 Compressed Air System

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

Note C8: A statement is required of estimated additional compressed air requirements together with a description of how these will be accommodated.

C9 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 C9: A statement is required of estimated treated raw water requirements together with a description of how these will be accommodated.

C10 Demineralisation I Desalination Plant

A supply of reasonably pure water may be required to make up evaporative losses from the flue gas cooler and/or scrubber. Estimates of this water requirement should be made and space allocated for the necessary treatment plant (and an additional water source be identified if necessary).
Note C10: A statement is required saying which of the above are needed and in what quantity and also describing how the necessary provisions will be implemented

C11 Waste Water Treatment Plant

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

Note C11: A statement is required giving estimated additional waste water treatment needs and describing how the necessary space and any other provisions will be provided to meet expected demands.

C12 Electrical

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

Note C12: A statement is required listing the estimated additional electrical requirements and describing space allocation in suitable

locations for items such as additional transformers, switching gear and cabling.

C13 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, additional cooling water piping and possibly other plant modifications.

Note C13: It is expected that provision will be made for space for routing new pipework at the appropriate locations. A statement identifying anticipated significant additional pipework and describing space allocations to accommodate these is required.

C14 Control and Instrumentation

Note C14: It is expected that space and provisions for additional control equipment and cabling will be implemented. A statement identifying anticipated additional control equipment and describing space and other provisions to accommodate these is required.

C15 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. Consideration should also be given to how, during a retrofit, vehicles or cranes will access the areas where new equipment will need to be erected.

Note C15: It is expected that the provisions above will be implemented. A statement identifying anticipated requirements and describing how they will be met is required.

Other technologies for post-combustion capture

C16 'Essential' Capture-Ready Requirements: Post Combustion Amine Scrubbing Technology based CO_2 Capture

The capture-ready requirements discussed in this section are the 'essential' requirements which aim to ease the capture retrofit of Natural Gas Combined Cycle power plants with post combustion amine scrubbing technology based CO_2 capture.

Note C16: The provisions covered in Notes C1-C15 can be adapted to include other liquid solvent mixtures for CO_2 capture that can be shown to have a reasonable expectation of being commercially available at the time of retrofit and for which reliable performance estimates are already available. A statement on where the requirements for capture readiness for such solvents differ from those for amine capture with respect to all of the relevant sections C1- C15 above is required, together with any additional CCR features or other actions proposed, to be added as addenda to the responses to Notes C1-C15. If making the plant capture ready for other solvents conflicts with the CCR requirements for amine

scrubbing then the impact on retrofitting amine scrubbing should be estimated and stated and the reasons for giving the other solvent priority should be listed and justified.