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GATEWAY ENERGY CENTRE

UPDATED CCR FEASIBILITY STUDY

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LIST OF ABBREVIATIONS

°C	degrees Celsius
ACC	Air Cooled Condenser
CCGT	Combined Cycle Gas Turbine
CCR	Carbon Capture Ready
CCS	Carbon Capture and Storage
CRH	Cold Re-Heat
CO_2	carbon dioxide
COMAH	Control of Major Accident Hazards
DECC	Department of Energy and Climate Change
ES	Environmental Statement
ES FID	Environmental Statement Further Information Document
EU	European Union
GEC	Gateway Energy Centre
GECL	Gateway Energy Centre Limited
ha	hectares
HRSG	Heat Recovery Steam Generator
HSC	Hazardous Substances Consent
HSE	Health and Safety Executive
kg/s	kilograms per second
km	Kilometres
IED	Industrial Emissions Directive
LCPD	Large Combustion Plant Directive
LG	London Gateway
m	metres
MEA	Mono-Ethanol Amine
Mt	mega tonnes
MW	megawatts
NO_x	nitrogen oxides
NO_2	nitrogen dioxide
OS	Ordnance Survey
SCR	Selective Catalytic Reduction
SO_x	sulphur oxides
t/h	tonnes per hour
UK	United Kingdom

1 INTRODUCTION

1.1 Overview

1.1.1 In February 2010, Gateway Energy Centre Limited (GECL) submitted an application for Consent under Section 36 of the Electricity Act 1989 (the Original Consent Application) to the Secretary of State for Energy and Climate Change (the Secretary of State) via then Department of Energy and Climate Change (DECC) to construct a 900 megawatt (MW) Combined Cycle Gas Turbine (CCGT) power plant to be known as Gateway Energy Centre or GEC. In addition, a direction that planning permission be deemed to be granted under Section 90 of the Town and Country Planning Act 1990 was also sought.

1.1.2 Amongst other documents / studies, the Original Consent Application was accompanied by an Environmental Statement (ES) (the February 2010 ES) and a Carbon Capture Readiness (CCR) Feasibility Study (the February 2010 CCR Feasibility Study).

1.1.3 Following submission of the Original Consent Application, consultation responses were received and meetings were held with key consultees from which clarifications were sought and supplementary information requested. In December 2010, GECL submitted the clarifications and supplementary information to DECC.

1.1.4 Amongst other documents / studies, the supplementary information to support the Original Consent Application included an Environmental Statement Further Information Document (ES FID) (the December 2010 ES FID).

1.1.5 On 4 August 2011, Consent under Section 36 of the Electricity Act 1989 and deemed planning permission under Section 90 of the Town and Country Planning Act 1990 was granted (the Original Consent).

1.2 Purpose of this Document

1.2.1 This document is an Updated CCR Feasibility Study, which accompanies an application by GECL to the Secretary of State for the Original Consent to be varied so as to allow an increase in the permitted generation capacity of GEC from about 900 MW[1] to up to 1250 MW (the Variation Application). The increase in permitted generation capacity would enable the use of the latest turbine technologies, including the Alstom GT26 (Amended), General Electric (GE) Flex 50, Mitsubishi Heavy Industries (MHI) 701 F5 and the Siemens SGT5-8000H machines. InterGen has selected Siemens as its preferred supplier and is expected to install two SGT5-8000H machines on the GEC site.

1.2.2 The above mentioned latest turbine technologies have net efficiencies of around 60 per cent, and carbon dioxide (CO_2) emissions of approximately 350 gCO_2/kWh. In comparison, the earlier turbine technologies assumed in the February 2010 ES (and the February 2010 CCR Feasibility Study) and the December 2010 ES FID had net efficiencies of around 55 per cent, and CO_2 emissions of approximately 390 gCO_2/kWh.

1.2.3 To accompany the Variation Application, GECL is providing the following information to DECC:

- An Updated Environmental Statement Further Information Document (the August 2014 ES FID), which includes (amongst other items):
    - o A comparison between the turbine technologies considered, and thus the rationale for proposing that the Original Consent is varied;
    - o An assessment of whether the likely significant effects on the environment of the Proposed Development differ from those described in the February 2010 ES and the December 2010 ES FID; and,
    - o Where there is potential for the likely significant effects on the environment of the Proposed Development to differ from those described in the February

[1] As per the Original Consent, a tolerance of up to 5% is permitted.

2010 ES and the December 2010 ES FID, an updated impact assessment. Where there is no potential for the likely significant effects to differ, an explanation and / or supporting information.

- This Updated CCR Feasibility Study, which includes a summary of the likely impacts on the conclusions of the 2010 CCR Feasibility Study, and an accompanying report by Imperial College London.

1.2.4 In considering the likely impacts on the conclusion of the 2010 CCR Feasibility Study, DECC and the Environment Agency has noted the need to re-assess several aspects of the assessments originally provided.

1.2.5 This Updated CCR Feasibility Study provides this reassessment and seeks to demonstrate that the increase in permitted generation capacity will remain fully compliant with the conclusions of the February 2010 CCR Feasibility Study.

2 LEGAL CONTEXT (THE PURPOSE OF A CCR FEASIBILITY STUDY) AND METHODOLOGY

2.1 EU Directive on the Geological Storage of Carbon Dioxide

2.1.1 On 17 December 2008, the European Union (EU) agreed the text of a new directive on the geological storage of carbon dioxide. On 5 June 2009, this text was published as the Directive on the geological storage of carbon dioxide (Directive 2009/31/EC) (the Carbon Capture and Storage (CCS) Directive) in the Official Journal of the European Union and came into force on 25 June 2009.

2.1.2 The CCS Directive required an amendment to Directive 2001/80/EC (commonly known as the Large Combustion Plant Directive (LCPD)) such that Member States are to ensure that operators of all combustion plants with an electrical capacity of 300 megawatts (MW) or more (and for which the construction / operating licence was granted after date of the CCS Directive) have assessed whether the following conditions are met:

- Suitable storage sites for CO_2 are available;
- Transport facilities to transport captured CO_2 to the storage sites are technically and economically feasible; and,
- It is technically and economically feasible to retrofit for the capture of CO_2.

2.1.3 The assessment of whether these conditions are met is to be submitted to the relevant competent authority who use the assessment (and other available information) in their decision-making process. If the conditions are met, the competent authority is to ensure that suitable space is set aside for the equipment necessary to capture and compress CO_2.

2.1.4 In the UK the relevant competent authority in respect of energy matters is DECC, which must ensure that the requirements of the relevant EU Directives are implemented.

2.1.5 It should also be noted that the requirement for the assessment is included in the more recent Directive 2010/75/EU on industrial emissions (integrated pollution prevention and control) (the Industrial Emissions Directive (IED)).

2.2 UK Government – CCR Policy

2.2.1 In June 2008, the UK Government published "*Towards Carbon Capture and Storage: A Consultation Document*" to seek views on the steps it could take to prepare for and support both the development and deployment of CO_2 capture technologies. A response to this consultation was published in April 2009, alongside information on the UK Government's CCR Policy and draft CCR Guidance for applicants seeking consent for new combustion power plant at or over 300 MWe[2].

2.2.2 The CCR Policy applied to new combustion power plants with an electrical capacity of 300 MW or more, with effect from 23 April 2009. Under the CCR Policy, all combustion power plant with an electrical capacity of 300 MW or more must be CCR and must set space aside to accommodate future CO_2 capture equipment.

2.2.3 The draft CCR Guidance was subject to an eight week consultation period which ended on 22 June 009. The responses from the consultation period were considered and incorporated, and the final CCR Guidance was published in November 2009[3].

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[2] Guidance on Carbon Capture Readiness and Applications under Section 36 of the Electricity Act 1989 (DECC, April 2009).
[3] Carbon Capture Readiness (CCR): A Guidance Note for Section 36 Electricity Act 1989 Consent Applications (DECC, November 2009).

UK Government CCR Policy Requirements

2.2.4 The CCR Guidance states (at paragraph 7) that 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 off shore exists for the storage of captured CO_2 from the proposed power station;*
- *The technical feasibility of transporting the captured CO_2 to the proposed storage area; and,*
- *The likelihood that it will be technically and 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".*

Further to the above: *"if Applicant's proposals for operational CCS involves 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 Section 36 Consent".*

2.3 UK Government – The Carbon Capture Readiness (Electricity Generating Stations) Regulations 2013

2.3.1 The Carbon Capture Readiness (Electricity Generating Stations) Regulations 2013 (the CCR Regulations) came into force on 25 November 2013, extending across Great Britain. These regulations summarise the need for a CCR Feasibility Study and state (at Regulation 2(1)) that a: *""CCR Assessment", in relation to a combustion plant, means an assessment as to whether the CCR Conditions are met in relation to that plant*".

2.3.2 In terms of the "*CCR Conditions*", CCR Regulation 2(2) states that: "*for the purposes of these Regulations, the CCR Conditions are met in relation to a combustion plant, if, in respect of all of its expected emissions of CO_2 –*

- *Suitable storage sites are available;*
- *It is technically and economically feasible to retrofit the plant with the equipment necessary to capture that CO_2; and,*
- *It is technically and economically feasible to transport such captured CO_2 to the storage sites referred to in sub-paragraph (a)*".

2.3.3 Furthermore, CCR Regulation 5(1) states that: *"The appropriate authority must not grant a relevant Section 36 Consent unless the appropriate authority has determined whether the CCR Conditions are met in relation to the combustion plant to which the Section 36 Consent relates".*

2.3.4 In summary, CCR Regulation 5(3) states that: *"If the appropriate authority –*

a) *Determines that the CCR Conditions are met in relation to a combustion plant; and*

b) *Decides to make a relevant Section 36 Consent in respect of that plant,*

it must include in the relevant Section 36 Consent a condition that suitable space is set aside for the equipment necessary to capture and compress all of the CO_2 that would otherwise be emitted from the plant".

2.3.5 It should be noted that the reference to "*all of its expected emissions of CO_2*" and "*all of the CO_2*" is likely to indicate that the applicant should be considering all of the CO_2 emissions from their power plant, rather than just a certain percentage of it (i.e. 50 per cent, 20 per cent). This is likely derived from the spirit of the CCS Directive (which the CCR Regulations transpose), which does not cover a fraction of the CO_2, but in principle relates to all of the CO_2.

2.3.6 For practical purposes, "*all of its expected emissions of CO_2*" and "*all of the CO_2*" can be considered to indicate that the applicant should be considering 'all of the CO_2 emissions from their power plant which can be captured using Best Available Techniques (BAT)'. This is in line with the CCR Guidance which states (at paragraph 11) that: "*Applicants should explain what percentage of these CO_2 emissions they consider will be captured by their proposed capture technology, in keeping with the principle of best practice*".

2.4 Approach / Methodology

2.4.1 To inform the preparation of this Updated CCR Feasibility Study, GECL commissioned a number of additional studies including a specific engineering investigation by Siemens. The aims of the engineering investigation were to verify whether the land set aside at GEC for the purposes of CCR (the CCS space) is sufficient for the proposed increase in permitted generation capacity.

2.4.2 The engineering investigation was based on a Siemens PostCap™ reference project, containing the results of a full process simulation including equipment dimensioning. Within the engineering investigation, the reference project was scaled to represent the proposed increase in permitted generation capacity requested for GEC. The results of this engineering investigation have been independently validated by Imperial College London. This validation is provided separately to this Updated CCR Feasibility Study.

2.5 Structure of this Document

2.5.1 As noted previously, this Updated CCR Feasibility Study demonstrates that, in light of the request for an increase in permitted generation capacity (from about 900 MW[4] to up to 1250 MW), GEC will remain fully compliant with the conclusions of the February 2010 CCR Feasibility Study and the requirements of the EU CCS Directive (and the EU IED Directive), the CCR Regulations and the CCR Guidance.

2.5.2 This Updated CCR Feasibility Study demonstrates that it remains feasible to retrofit a CCS Chain to GEC within its 35 year operating lifetime and largely follows the sequence of the February 2010 CCR Feasibility Study providing additional and supplementary information where necessary. Where no changes or supplementary information are deemed necessary / have been requested, this is stated at the beginning of the Section.

[4] As per the Original Consent, a tolerance of up to 5% is permitted.

3 PROPOSED DEVELOPMENT

3.1 GEC

3.1.1 The GEC site is situated on the north bank of the Thames Estuary, approximately 6 km east of the A13. The A1014 dual carriageway (The Manorway) lies approximately 0.5 km to the north of the site and runs east to west to provide a link with the A13, which in turn connects with the M25 at Junction 30. The Ordnance Survey (OS) Grid Reference of the centre of the GEC site is approximately 573209, 182165.

3.1.2 The nearest residential settlements are at Corringham and Fobbing approximately 4 km to the west, Canvey Island approximately 5 km to the east and Basildon approximately 7 km to the north.

3.1.3 To the east of the GEC site lies the Shell Aviation Fuel Storage Farm (100 m), existing Coryton CCGT power plant (700 m east), and the existing Thames OilPort / former Petroplus Coryton Oil Refinery (950 m east).

3.1.4 The overall application site boundary covers a total area of approximately 29.1 hectares (ha) (71.9 acres). This includes:

- The GEC site, which has a total area of approximately 11.3 ha (28.0 acres) and includes the land to be set aside for the purposes of CCR (the CCS space); and,
- Land to the north and west which is intended to be used for temporary laydown and storage of plant / equipment during construction.

3.1.5 GEC will provide up to 1250 MW of power generation capacity. This will include the provision of up to 150 MW to the London Gateway® Logistics Park, which is expected to meet its long-term electricity requirements.

3.1.6 Additionally, GEC will be designed in such a way as to enable the supply of heat in the form of steam and / or hot water (for use in production / space heating / cooling) to facilities and / or customers in the vicinity of the GEC site (in particular to prospective customers of the London Gateway® Logistics Park).

3.1.7 GEC will comprise up to two gas turbine units which will be fuelled by natural gas. Each unit will include a gas turbine and a Heat Recovery Steam Generator (HRSG) which will serve steam turbine equipment.

3.1.8 The natural gas will be burnt in the combustion chamber of each gas turbine from where the hot gases will expand through the gas turbine to generate electricity. The hot exhaust gases are then used in the HRSG to generate steam, which is in turn used to generate electricity via steam turbine equipment.

3.1.9 The use of a combined gas and steam cycle increases the fuel efficiency of the power plant, compared with that of simple cycle gas turbines.

3.1.10 The steam exhausting the steam turbine equipment will pass to an Air Cooled Condenser (ACC) where it will be condensed. The resultant condensate will be returned to the HRSGs to continue the steam cycle.

3.2 CO_2 Output / Design Case for this Updated CCR Feasibility Study

3.2.1 As noted in Section 2.4, to inform the preparation of this Updated CCR Feasibility Study, GECL commissioned a number of additional studies, including a specific engineering investigation by Siemens. The aim of the engineering investigation was to verify whether the CCS space available at GEC was sufficient for the proposed increase in permitted generation capacity.

3.2.2 The engineering investigation was based on a Siemens PostCap™ reference project, containing the results of a full process simulation including equipment dimensioning. Within the engineering investigation, the reference project was scaled to represent the proposed increase in permitted generation capacity requested for GEC. The results of this engineering investigation have been independently validated by Imperial College London. This validation is provided separately to this Updated CCR Feasibility Study.

3.2.3 The base turbine technology for the reference project comprised three Siemens SGT5-4000F gas turbines (modelled in single shaft configuration), and the resulting CO_2 capture plant was then based on a modular 3-train approach. This is called the 'Design Case'.

3.2.4 A comparison between the Design Case (utilising the 3 x SGT5-4000F gas turbines) and GEC (utilising 2 x SGT5-8000H gas turbines, to provide the increase in permitted generation capacity) is shown in Table 3.1.

TABLE 3.1: COMPARISON BETWEEN THE DESIGN CASE FOR THIS UPDATED CCR FEASIBILITY STUDY AND GEC WITH THE PROPSOED INCREASE IN PERMITTED GENERATION CAPACITY

Parameter		*Design Case*	*GEC with Increase in Permitted Generation Capacity*
Approx. Flue Gas Stream	t/h	7,623	6,143
Approx. Flue Gas Inlet Temperature	°C	81.6	81

3.2.5 The total flue gas to be treated for the Design Case is larger than the amount for GEC with the proposed increase in permitted generation capacity. Therefore, it can be concluded that if the CCS space available at GEC is sufficient for the Design Case, it is also sufficient for the proposed increase in permitted generation capacity.

3.3 Options Considered

3.3.1 The February 2010 CCR Feasibility Study noted two main Options which would influence the sizing of the CCS Chain for GEC. These were referred to as Option A and Option B and were related to the way in which steam was generated for the CO_2 capture process. In brief:

- ***Option A:***

  Steam for the CO_2 capture process is taken from the steam cycle of GEC.

- ***Option B:***

  Steam for the CO_2 capture process is generated by auxiliary boilers.

3.3.2 Option A will impose a greater requirement in terms of retrofitting if CO_2 capture equipment is installed. For example, if a largely standard CCGT power plant design is installed, then after retrofitting, the CCGT power plant may be less efficient then if a 'non-standard CO_2 capture optimised' CCGT power plant design is installed. However a 'non-standard CO_2 capture optimised' CCGT power plant design would likely incur an efficiency penalty during CCGT power plant only operation.

3.3.3 Option B will require minimal changes to be made in terms of retrofitting if CO_2 capture equipment was installed. However, additional gas would be required for the auxiliary boilers. This could increase the size of the CCS Chain if the additional CO_2 in the auxiliary boilers flue gas was combined with the flue gases from the CCGT power plant, prior to entering the CO_2 capture process.

3.3.4 Whilst both Option A and Option B are available for GEC, Option A was the main focus of the February 2010 CCR Feasibility Study and remains the focus of this Updated CCR Feasibility Study.

3.4 Estimation of the Sizing of the CCS Chain

3.4.1 It is expected that the CO_2 capture equipment installed will capture up to 90 per cent of the CO_2 in the flue gases. However, the actual amount will be dependent upon the temperature of the CO_2 capture process and the amount of process cooling available at the time of installation.

3.4.2 Based on this CO_2 capture rate, the sizing of the CCS Chain for Option A (including capture, compression / liquefaction, transport and storage) is based on the information in Table 3.2.

TABLE 3.2: SIZING FOR THE CCS CHAIN

CCS Chain Component		***Design Case***	***GEC with Increase in Permitted Generation Capacity***
Approx. Flue Gas Stream	t/hr	7,623	6,143
CO_2 Content in Flue Gas Stream	%vol	3.7	4.6
CO_2 Generated	t/hr	437	407
Approx. CO_2 Captured	t/hr	393	366
(Assuming 90 per cent CO_2 capture rate)	t/day	9,432	8,784
CO_2 Stored (Assuming 75 per cent lifetime capacity factor of GEC[5])	Mt/year	-	2.40
Total CO_2 Stored (Assuming 35 years of CO_2 capture)	Mt	-	84.2

3.4.3 For operation under Option A, based on the Design Case, the CO_2 capture process will be capable of handling a CO_2 flow rate of up to a maximum of approximately 393 t/h. On this basis the CO_2 capture process will be capable of processing a CO_2 flow rate up to a maximum of approximately 9,432 t/day. However, as noted previously, the total flue gas to be treated for the Design Case is larger than the flue gas amount for GEC with the proposed increase in permitted generation capacity. Therefore, it is considered that a worst case scenario is presented in this Updated CCR Feasibility Study and in reality the requirements are likely to be reduced.

3.4.4 The total annual throughput for the CCS Chain will vary, and be dependent on the operational profile for GEC. However, with a 75 per cent lifetime capacity factor, the total amount of CO_2 to be stored over a 35 year period will be approximately 84.2 Mt.

[5] This is the expected operational load on GEC over its lifetime. Note this is different to the availability of GEC which is estimated (in the February 2010 ES and the December 2010 ES FID) to be 93 per cent.

4 PROPOSED CO_2 CAPTURE PLANT TECHNOLOGY

4.1 Current Understanding

4.1.1 The current understanding is that the CO_2 capture plant / equipment will not be installed until CO_2 capture is either mandated or economically beneficial.

4.1.2 A number of CO_2 capture technologies currently exist, and at the time of eventual installation, it is highly probable that this number will have increased. However, similar to the February 2010 CCR Feasibility Study, this Updated CCR Feasibility Study focuses on the technology that is closest to commercial deployment. This Updated CCR Feasibility Study focuses on currently available technology rather than speculating on any future developments that may be available when the CO_2 capture plant is ultimately installed. Whilst many of these future developments are likely, it would be difficult to demonstrate that a power plant was CCR if it was dependent on uncertain and unproven future technical developments.

4.1.3 The technical assessments in this Updated CCR Feasibility Study are based on the assumption of post-combustion capture via chemical absorption using an amino acid salt. The underlying baseline engineering investigation was based on a Siemens PostCap™ reference project.

4.1.4 Testing and validation of the Siemens PostCap™ design has been undertaken at an automated, continuously operating laboratory pilot plant at Industrial Park Frankfurt-Hoechst in Germany. This laboratory pilot plant allowed for development and improvement in CO_2 process robustness, solvent selection and characterisation of chemical behaviour. In addition, validation of the process design features and corrosion tests with construction materials were undertaken.

4.1.5 In addition, since September 2009, further testing of the Siemens PostCap™ design has been undertaken at a pilot plant fed with real flue gas from E.ON's coal-fired power plant at Staudinger in Germany. This PostCap™ pilot plant represents a fully operational plant which has been operated for more than 6,000 hours under real flue gas conditions. Siemens have noted that the measured results from this pilot plant are well in line with the expectations derived from earlier phases and the laboratory pilot plant which were used for the up-scaling of the technology.

4.1.6 Furthermore, since November 2012, the PostCap™ pilot plant at Staudinger has been operated under natural gas burner flue gas conditions. This was part of the Technology Qualification Program for Statoil and Gassnova's full scale CO_2 Capture Mongstad project. This Technology Qualification Program was successfully completed in May 2013 following operation for more than 3,000 hours.

4.1.7 Therefore, it is understood that no technical barriers exist to extending, retrofitting and integrating this CO_2 capture technology at GEC.

4.2 Previous CO_2 Capture Plant Technology in the February 2010 CCR Feasibility Study

4.2.1 It should be noted that the CO_2 capture process assumed in this Updated CCR Feasibility Study is very similar to that used in the February 2010 CCR Feasibility Study. Indeed, the main process stages are virtually identical. The main difference is the type of solvent used.

4.3 Siemens PostCap™ Reference Project Description

4.3.1 The following provides a summary description of the Siemens PostCap™ reference project CO_2 capture process. The main process stages include:

- Flue gas cooling;
- Flue gas blowing;
- Absorption section;

- Desorption section;
- CO_2 compression section;
- Reclaimer section; and,
- Storage and unloading section.

4.3.2 An illustrative process schematic is provided in Appendix A. As noted in Section 3, the total flue gas stream is divided into three streams based on a modular 3-train approach (train A, B and C) for the CO_2 capture plant / equipment. It can be assumed that the 3-train approach can also be used for treating the exhaust gases of two larger gas turbines. This would limit the size of vessels and other equipment, and corresponds to the size of vessels that are currently commercially available.

Flue Gas Cooling

4.3.3 Post combustion, the flue gases are cooled for processing in the CO_2 capture plant / equipment. This cooling ensures the most effective conditions for CO_2 absorption. Within the illustrative process schematic in Appendix A, to ensure optimised flue gas cooling, flue gas coolers are shown as items T001A/B/C. The temperature of these flue gas coolers is controlled via heat exchangers, shown as items E001A/B/C.

Flue Gas Blowing

4.3.4 Post cooling, the flue gases are delivered to the absorption section, aided by the use of booster fans, shown as items C001A/B/C. The use of these booster fans will ensure that there is no pressure increase at the upstream CCGT power plant stacks, and therefore no increase in back pressure on the gas turbines.

Absorption Section

4.3.5 In the absorption columns, shown as items T002A/B/C, the flue gases come into contact with the lean amino acid salt solvent. This lean solvent absorbs up to 90 per cent of the CO_2 in the flue gases. To achieve the most effective conditions for CO_2 absorption, the temperature of the lean solvent is controlled via a dedicated lean solvent cooler, shown as items E002A/B/C.

4.3.6 The cleaned flue gases are emitted from the top of the absorption column. Each absorption column is equipped with a demister to prevent the dragging of solvent droplets to the atmosphere.

4.3.7 The rich solvent (which has absorbed up to 90 per cent of the CO_2 in the flue gas) exits the bottom of the absorption column, and is pumped (via items P002A/B/C) to a combined header.

4.3.8 From the combined header, the rich solvent splits into two streams[6]. A minor stream is fed straight to the top of the desorber column, shown as item T003. The major stream is fed to the rich / lean solvent heat exchanger, shown as item E003, where the rich solvent stream is heated by the lean solvent stream returning from the desorber column. On the other side of the heat exchanger, the lean solvent stream is cooled by the rich solvent stream. On exiting the heat exchanger, the major stream of rich solvent is then fed to the desorber column.

Desorption Section

4.3.9 In the desorber column, the rich solvent is then heated further by the use of steam from a reboiler, shown as item E005. The amino acid salt can absorb less CO_2 at higher temperatures, so heating the rich solvent releases the CO_2 as a gas.

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[6] This approach represents an optimisation to reduce the energy demand of the CO_2 capture process.

4.3.10 The lean solvent is pumped from the bottom of the desorber column, through the rich / lean solvent heat exchanger, and then split into three streams to be fed back to the lean solvent coolers.

4.3.11 The desorbed CO_2, containing a large quantity of steam, exits the top of the desorber column and is fed to the desorber condenser, shown as item E004. The CO_2 (and other non-condensable vapour) are routed to the CO_2 compressor, shown as item C003. The condensed water is fed back to the top of the desorber column.

CO_2 Compression Section

4.3.12 In the CO_2 compressor, the CO_2 and non-condensable vapour are compressed in back to back compressor stages. Any condensed water is collected and will be pumped to either the Waste Water Treatment Plant or discharged to the London Gateway® Logistics Park drainage system swale.

Reclaimer Section

4.3.13 A reclaimer, shown as item PU001, serves to reduce by-products resulting from solvent degradation mainly caused by nitrogen oxides (NO_x) and sulphur oxides (SO_x) contained in the flue gas stream and enhance the recovery of the solvent. Therefore, a minor stream of lean solvent downstream of the lean solvent coolers is separated and sent to the reclaimer. Regenerated solvent is fed back to the CO_2 capture process.

5 TECHNICAL ASSESSMENT – CCS SPACE REQUIREMENTS

5.1 Previous Findings of the February 2010 CCR Feasibility Study / Update to the CCR Guidance Requirements

5.1.1 The existing CCS space available at GEC is 4.7 ha.

5.1.2 In the February 2010 CCR Feasibility Study, it was identified that:

- Under Option A (at 900 MW, 55 per cent net efficiency), the CCS space required was approximately 3.1 ha; and,
- Under Option B (at 900 MW, 55 per cent net efficiency with auxiliary boilers), the CCS space required was approximately 3.8 ha.

5.1.3 Table 1 of the CCR Guidance provides an indicative CCS space requirement based on 500 MW (net) power plants. For a CCGT power plant with post-combustion CO_2 capture, the original indicative CCS space requirement was 3.75 ha for 500 MW (original CCS space requirement). Subsequent to the publication of the CCR Guidance, this original indicative CCS space requirement was reviewed by Imperial College London[7]. The review by Imperial College London resulted in the correction of the indicative CCS space requirement for a CCGT with post-combustion CO_2 capture by 36 per cent to 2.4 ha (corrected CCS space requirement). In addition, the review by Imperial College London further detailed additional scope for a reduction in the indicative CCS space requirement by 50 per cent to 1.875 ha (including the reduction of 36 per cent) considering technology advances and layout optimisation (i.e. assuming one carbon capture train per gas turbine unit train) (further reduced CCS space requirement).

5.1.4 Table 5.1 presents a summary of these CCS space requirements in terms of the existing CCS space available at GEC.

TABLE 5.1: SUMMARY OF CCS SPACE REQUIREMENTS, BASED ON CCR GUIDANCE AND IMPERIAL COLLEGE LONDON REVIEW

Parameter	***900 MW (GEC)***	***1250 MW (GEC with Increase in Permitted Generation Capacity)***
Size (MW)	900	1250
Existing CCS Space Available (ha)	4.7	
Original CCS Space Requirement[8] (ha)	6.8	9.4
As a proportion of space available %	144.7	200.0
Corrected CCS Space Requirement[9] (ha)	4.3	6.0
As a proportion of space available %	91.4	127.7
Further Reduced CCS Space Requirement[10] (ha)	3.4	4.7
As a proportion of space available %	72.3	100.0

5.1.5 Based on the use of Table 5.1 it can be seen that with based on the use of the further reduced CCS space requirement, the existing CCS space available at GEC is sufficient for GEC with the proposed increase in permitted generation capacity. However, the review

[7] Review available at: http://www.decc.gov.uk/en/content/cms/meeting_energy/consents_planning/electricity/electricity.aspx
[8] Based on 3.75 ha for a 500 MW (net) CCGT power plant with post-combustion CO_2 capture.
[9] Based on 2.4 ha for a 500 MW (net) CCGT power plant with post-combustion CO_2 capture.
[10] Based on 1.875 ha for a 500 MW (net) CCGT power plant with post-combustion CO_2 capture.

by Imperial College London stated that this would only be justified on the basis of a more detailed engineering study which is not currently a requirement for Section 36 Consent.

5.2 Technical Assessment

5.2.1 Accordingly, as noted in Section 2.4, further to the approach used within the February 2010 CCR Feasibility Study, GECL commissioned a number of additional studies for this Updated CCR Feasibility Study, including a specific engineering investigation by Siemens. The aims of the engineering investigation were to verify whether the CCS space available at GEC was sufficient for the proposed increase in permitted generation capacity.

5.2.2 The engineering investigation was based on a Siemens PostCap™ reference project, with the reference project containing the results of a full process simulation including equipment dimensioning. Within the engineering investigation, the reference project was scaled to match the proposed increase in generation capacity requested for GEC.

5.2.3 The results of this engineering investigation have been independently validated by Imperial College London.

5.2.4 Based on the engineering investigation, an illustrative site layout (for the Design Case) has been prepared which indicates:

- The location of the CO_2 capture plant / equipment;
- The location of the CO_2 compression equipment;
- The location of the chemical storage facilities; and,
- The exit point for the CO_2 pipeline (the CO_2 terminal point).

5.2.5 In terms of the CO_2 terminal point, this has been placed to match the original CO_2 terminal point in the February 2010 CCR Feasibility Study (i.e. on the eastern boundary of the GEC site). The CO_2 terminal point has been placed to match the most likely onshore CO_2 pipeline route described in Section 8 of the February 2010 CCR Feasibility Study.

5.2.6 The illustrative site layout is provided in Appendix B. The illustrative site layout shown in Appendix B covers an area of 4.5 ha. This area is smaller than the existing CCS space available at GEC which covers an area of 4.7 ha.

5.2.7 Therefore, as the existing CCS space available is sufficient for the Design Case, it is concluded that it is also sufficient for GEC with the proposed increase in permitted generation capacity.

5.3 Future Considerations

5.3.1 The CCS space requirements will be reviewed as part of the Status Reports[11]. These Status Reports will provide an opportunity for reassessment / review of the above, particularly regarding developments in CO_2 capture technologies.

[11] The first Status Report is required within 3 months of the commencement of commercial operation of the power plant, and then every two years thereafter until the power plant moves to retrofit CCS.

6 TECHNICAL ASSESSMENT – RETROFITTING AND INTEGRATION OF CCS

6.1 Previous Findings of the February 2010 CCR Feasibility Study / CCR Guidance Requirements

6.1.1 In the February 2010 CCR Feasibility Study, the technical assessment was based on an assumption of post-combustion capture via chemical absorption using an amine solvent, with the named solvent being Mono-Ethanol Amine (MEA). This technical assessment found that there were no foreseeable technical barriers to the retrofitting and integration of CCS at GEC.

6.1.2 The CCR Guidance notes that the aim of this technical assessment is to demonstrate that GEC has been designed in such a way so as to enable subsequent retrofitting and integration of CO_2 capture equipment.

6.1.3 The technical assessment is to be made against the information provided in Annex C (Environment Agency verification of CCS Readiness New Natural Gas Combined Cycle Power Station using Post Combustion Solvent Scrubbing) of the CCR Guidance. Annex C is provided in full in Appendix C.

6.2 Technical Assessment

C1: Design, Planning Permissions and Approvals

6.2.1 Taken together, the February 2010 CCR Feasibility Study and this Updated CCR Feasibility Study show that it is technically feasible to retrofit CO_2 capture equipment and a full CCS Chain at GEC.

6.2.2 An illustrative site layout is provided in Appendix B.

C2: Power Plant Location

6.2.3 Taken together, the February 2010 CCR Feasibility Study and this Updated CCR Feasibility Study show that it is technically feasible to transport captured CO_2 to an existing offshore CO_2 storage area as part of a full CCS Chain at GEC.

6.2.4 In terms of the CO_2 terminal point, this has been placed to match the original CO_2 terminal point in the February 2010 CCR Feasibility Study (i.e. on the eastern boundary of the GEC site). The CO_2 terminal point has been placed to match the most likely onshore CO_2 pipeline route described in Section 8 of the February 2010 CCR Feasibility Study.

C3: Space Requirements

6.2.5 As required by the CCR Guidance, the following is specifically noted:

a) The provision of space for the main items of CO_2 capture plant / equipment (including flue gas pre-treatment and CO_2 drying and compression) is shown on the illustrative site layout in Appendix B.

b) The provision of space for new duct work to allow interconnection of the existing flue gas system with the CO_2 capture plant / equipment is show on the illustrative site layout in Appendix B.

c) The provision of space for additional plant infrastructure (including roads in reasonable proximity to the key items of plant / equipment and the loading / unloading area and solvent storage) is shown on the illustrative site layout in Appendix B.

d) The provision of space for loading and unloading solvent, and solvent storage, is shown on the illustrative site layout in Appendix B. In terms of the CO_2 terminal point, this has been placed to match the original CO_2 terminal point in the February 2010 CCR Feasibility Study (i.e. on the eastern boundary of the GEC site).

6.2.6 In combination with the above, it should be noted that the tender specifications for GEC will include the following:

- The provision of space within GEC for the future addition of flue gas off-take ducting, flue gas diversion mechanisms and access for retrofit / maintenance;
- The provision of space within GEC for new duct work to allow interconnection of the existing flue gas system with the CO_2 capture plant / equipment;
- The provision of space within GEC for additional pipe work / pipe work support (likely to be beneath the new duct work);
- The provision of space within the turbine hall of GEC to allow for steam off-take, including space surrounding blanked-off off-take ports for addition of off-take pipe work (including isolation and bypass valves) and access for retrofit / maintenance;
- The provision of space within GEC for the return pipe work / pipe work support (i.e. for condensate to the feedwater system); and,
- The provision of space to allow for additional raw water requirements, additional demineralised water requirements, additional waste water treatment requirements and additional compressed air requirements.

C4: Gas Turbine Operation with Increased Exhaust Pressure

6.2.7 Based on the introduction of CO_2 capture plant / equipment at GEC, the gas turbine (and upstream ducting / HRSG) may be subject to increased back pressure unless a booster fan is provided.

6.2.8 The provision of space for three booster fans (one associated with each of the 3-trains) is shown on the illustrative site layout in Appendix B. The use of these booster fans will ensure that there is no pressure increase at the upstream CCGT power plant stacks, and therefore no increase in back pressure on the gas turbines.

6.2.9 These booster fans will likely be constructed of stainless steel / coated carbon steel, and will be designed for a flue gas flow rate of approximately 2,500 t/hr.

6.2.10 Therefore, it is considered that there are no foreseeable technical barriers to retrofitting and integration of CCS in terms of gas turbine operation with increased exhaust pressure.

C5: Flue Gas System

6.2.11 The provision of space for new duct work to allow interconnection of the existing flue gas system with the CO_2 capture plant / equipment is shown on the illustrative site layout in Appendix B.

6.2.12 In addition, Selective Catalytic Reduction (SCR) is not deemed to be required for the CO_2 capture process assumed in this Updated CCR Feasibility Study as the LCPD (and IED) limits for NO_x will result in a flue gas containing a concentration of nitrogen dioxide (NO_2) that will not impact on the CO_2 capture process.

6.2.13 Therefore, it is considered that there are no foreseeable technical barriers to retrofitting and integration of CCS in terms of the flue gas system.

C6: Steam Cycle

6.2.14 Steam is required for the stripping of the CO_2 from the rich amino acid salt in the desorption section of the CO_2 capture process. Based on the Siemens PostCap™ reference project, the estimated steam extraction requirement for the CO_2 capture plant / equipment is:

- Steam Pressure: 4.6 bar a;
- Steam Flow: 502 t/hr; and
- Steam Temperature: 148.7°C.

6.2.15 Based on implementing Option A (steam for the CO_2 capture process is taken from the steam cycle of GEC), several off-take options exist. However, similar to the February 2010 CCR Feasibility Study, in this Updated CCR Feasibility Study steam extraction is from the Cold Re-Heat (CRH) as this is the most universally retrofittable option for any CCGT power plant arrangement.

6.2.16 In terms of retrofitting and integration, steam extraction from the CRH would require space for an off-take port on each CRH line as well as increasing the de-superheating capability. If this is employed, steam extraction could be undertaken at any pressure up to the pressure of the CRH. This option does not require an extraction port, and therefore is independent of the choice of turbine technology manufacturer.

6.2.17 Without the CO_2 capture process, the net electrical output of GEC is estimated as 1160 MW, at a lower heating value (LHV) efficiency of 59.5 per cent. Based on steam extraction from the CRH, the effect of the CO_2 capture process on the performance of GEC is a reduction of net electrical output of approximately 150 MW, including the additional auxiliary power requirements. Therefore, the overall net electrical output of GEC with CO_2 capture is approximately 1010 MW at an efficiency of approximately 51.8 per cent.

C7: Cooling Water System

6.2.18 An additional cooling duty will be imposed by the CO_2 capture plant / equipment at GEC. This additional cooling duty will be required for:

- Cooling the flue gases to absorber temperature (flue gas cooling);
- Cooling the lean amino acid before entry into the absorber (process cooling);
- Cooling the CO_2 / condensing of water in the CO_2 product before and between compression stages (inter-cooling); and,
- Cooling of the CO_2 capture ancillary plant / equipment.

6.2.19 The additional cooling duty was estimated during the engineering investigation was based on the Siemens PostCap™ reference project. The result indicated that the additional cooling duty is approximately 672 MW.

6.2.20 Similar to the February 2010 CCR Feasibility Study, this Updated CCR Feasibility Study assumes that the additional cooling duty will be met by fin-fan air cooling. The space requirement for fin-fan air coolers is approximately 16 m^2 per MW of cooling duty. There will be no continuous make up water requirements for this cooling system.

6.2.21 Therefore, the space required for the additional cooling duty is estimated to be approximately 10,800 m^2. Space available for fin-fan coolers is shown on the illustrative site layout in Appendix B, and covers approximately 11,100 m^2.

6.2.22 Therefore, subject to detailed design being carried out, it is considered that there are no foreseeable technical barriers to retrofitting and integration of CCS in terms of additional cooling duty.

C8: Compressed Air System

6.2.23 Additional compressed air will be required for the CO_2 capture plant / equipment. At present this is estimated to be approximately 750 Nm^3/hr. The provision of space for this additional compressed air requirement will be provided within the Compressed Air System at GEC. The requirement for the provision of this space will be included in the tender specification for GEC.

6.2.24 Therefore, subject to detailed design being carried out, it is considered that there are no foreseeable technical barriers to retrofitting and integration of CCS in terms of additional compressed air requirements.

C9: Raw Water Pre-Treatment Plant

6.2.25 It is not expected that the additional water requirement of the CO_2 capture plant / equipment will be significant. However, the provision of space for any raw water storage and treatment will be provided with the Water / Firewater Storage Tank and the Water Treatment Building at GEC. The requirement for the provision of this space will be included in the tender specifications for GEC.

6.2.26 Therefore, subject to detailed design being carried out, it is considered that there are no foreseeable technical barriers to retrofitting and integration of CCS in terms of additional raw water requirements.

C10: Demineralisation / Desalination Plant

6.2.27 Additional demineralised water will be required to replace water removed during the amino acid salt reclaiming process. At present, this is estimated to be approximately 1 m^3/hr. The provision of space for this additional demineralised water requirement will be provided within the Water Treatment Plant at GEC. The requirement for the provision of this space will be included in the tender specifications for GEC.

6.2.28 Therefore, subject to detailed design being carried out, it is considered that there are no foreseeable technical barriers to retrofitting and integration of CCS in terms of additional demineralised water requirements.

C11: Waste Water Treatment Plant

6.2.29 If necessary, the waste water from the CO_2 capture plant / equipment will be directed into the Waste Water Treatment Plant at GEC. The resulting effluent will be discharged into the London Gateway® Logistics Park drainage system swale. Alternatively, the waste water will be directly discharged into the London Gateway® Logistics Park drainage system swale. All waste water will be treated to control concentrations of various compounds to within the limits prescribed by an Environmental Permit.

6.2.30 Therefore, the provision of space for any additional waste water generated will be provided within the Waste Water Treatment Plant at GEC and the London Gateway® Logistics Park drainage system swale. The requirement for the provision of this space will be included in the tender specifications for GEC.

6.2.31 In addition, the final design of the CO_2 capture plant will include provisions for surface water drainage, contaminated surface water drainage (which will initially drain to oil interceptors) and process water drainage. This will also be discharged into the London Gateway® Logistics Park drainage system swale.

6.2.32 Therefore, subject to detailed design being carried out, it is considered that there are no foreseeable technical barriers to retrofitting and integration of CCS in terms of additional waste water.

C12: Electrical

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

6.2.34 However, the retrofitting and integration of CO_2 capture plant / equipment to GEC will lead to an estimated electrical requirement of approximately 93 MW. At this stage it is suggested that this is met by a reduction in the electrical output from GEC to the National Grid Electricity Transmission System using auxiliary transformers.

6.2.35 The provision of space for additional electrical plant / equipment associated with specific power plant / CO_2 capture plant items (i.e. pumps / fans) will be provided within the respective plant item areas. This additional electrical plant / equipment is small in size and could be readily accommodated.

6.2.36 Therefore, subject to detailed design being carried out, it is considered that there are no foreseeable technical barriers to retrofitting and integration of CCS in terms of electrical.

C13: Plant Pipe Racks

6.2.37 The provision of space for plant pipe racks within the CCS space can be seen in the illustrative site layout in Appendix B. These plant pipe racks allow for the installation of additional pipe work between GEC and the CO_2 capture plant / equipment. The provision of space for plant pipe racks at GEC will be included in the tender specifications for GEC.

6.2.38 Therefore, subject to detailed design being carried out, it is considered that there are no foreseeable technical barriers to retrofitting and integration of CCS in terms of plant pipe racks.

C14: Control and Instrumentation

6.2.39 The control and instrumentation system for the CO_2 capture plant / equipment is anticipated to be incorporated into the Distributed Control System (DCS) of GEC (i.e. will be within the Control Building at GEC). Therefore, the provision of space for the control and instrumentation system will comprise that to be used for the routing of cabling to / from and the installation of equipment within the Control Building at GEC. The requirement for the provision of this space will be included in the tender specifications for GEC.

6.2.40 Therefore, subject to detailed design being carried out, it is considered that there are no foreseeable technical barriers to retrofitting and integration of CCS in terms of control and instrumentation.

C15: Plant Infrastructure

6.2.41 The provision of space for plant infrastructure (i.e. the CO_2 capture plant / equipment) can be seen in the illustrative site layout in Appendix B. In addition, the design basis for GEC ensures that offices and store are sufficiently sized for the additional requirements of the CO_2 capture plant / equipment.

6.2.42 Furthermore, the GEC site is accessible from the existing road network, and is not considered to have any access constraints which could impede future construction / operational activities.

6.2.43 Therefore, it is considered that there are no foreseeable technical barriers to retrofitting and integration of CCS in terms of plant infrastructure.

C16: Other Technologies for Post-Combustion Capture / 'Essential' Capture Ready Requirements

6.2.44 As noted in Section 4, the assessments in this Updated CCR Feasibility Study are based on the assumption of post-combustion capture via chemical absorption, but using an amino acid salt. The underlying baseline engineering investigation was based on a Siemens PostCap™ reference project.

6.2.45 Testing and validation of the Siemens PostCap™ design has been undertaken at an automated continuously operating laboratory pilot plant at Industrial Park Frankfurt-Hoechst in Germany. This laboratory pilot plant allowed for development and improvement in CO_2 process robustness, solvent selection and characterisation of chemical behaviour. In addition, validation of the process design features and corrosion tests with construction materials were undertaken.

6.2.46 In addition, since September 2009, further testing of the Siemens PostCap™ design has been undertaken at a pilot plant fed with real flue gas from E.ON's coal-fired power plant at Staudinger in Germany. This PostCap™ pilot plant represents a fully operational plant which has been operated for more than 6,000 hours under real flue gas conditions. Siemens have noted that the measured results from this pilot plant are well in line with the expectations derived from earlier phases and the laboratory pilot plant which were used for the up-scaling of the technology.

6.2.47 Furthermore, since November 2012, the PostCap™ pilot plant at Staudinger has been operated under natural gas burner flue gas conditions. This was part of the Technology Qualification Program for Statoil and Gassnova's full scale CO_2 Capture Mongstad project. This Technology Qualification Program was successfully completed in May 2013 following operation for more than 3,000 hours.

6.2.48 Therefore, it is considered that there are no foreseeable technical barriers to retrofitting and integration of CCS in terms of implementing post-combustion capture via chemical absorption using an amino acid salt solution.

6.3 Future Considerations

6.3.1 The requirements for retrofitting and integration of CCS will be reviewed as part of the Status Reports. These Status Reports will provide an opportunity for reassessment / review of the above, particularly regarding developments in CO_2 capture technologies.

7 TECHNICAL ASSESSMENT – CO_2 STORAGE AREAS

7.1 Previous Findings of the February 2010 CCR Feasibility Study

7.1.1 In order to determine any CO_2 storage areas, it is necessary to have an idea of the CO_2 storage requirements of GEC. In the February 2010 CCR Feasibility Study, it was identified that:

- Under Option A (at 900 MW, 55 per cent net efficiency), the CO_2 storage requirement was approximately 64.0 Mt of CO_2;
- Under Option B (at 900 MW, 55 per cent net efficiency with auxiliary boilers), the CO_2 storage requirement was approximately 74.0 Mt of CO_2; and,
- GEC would use either the Hewett (L Bunter) or Leman gas field to satisfy this CO_2 storage requirement.

7.1.2 In addition to the above, the February 2010 CCR Feasibility Study noted (at paragraph 7.2.5) that the Hewett (L Bunter) gas field had a CO_2 storage capacity of 237 Mt of CO_2, and the Leman gas field had a CO_2 storage capacity of 1,203 Mt of CO_2. The percentage CO_2 storage requirements of GEC against these CO_2 storage capacities were reported in Table 6 of the February 2010 CCR Feasibility Study.

7.2 Technical Assessment

7.2.1 In line with the calculations summarised in Table 3.2 for Option A, the CO_2 storage requirements of GEC with the proposed increase in permitted generation capacity will be a maximum of approximately 84.2 Mt.

7.2.2 Accordingly, the updated percentage CO_2 storage requirement of GEC against the same CO_2 storage capacities is presented in Table 7.1.

TABLE 7.1: PERCENTAGE CO_2 STORAGE REQUIREMENT OF GEC

	Option A ***Up to a Maximum of approximately 84.2 Mt of CO_2***
Hewett (L Bunter) 237 Mt of CO_2	35.5%
Leman 1203 Mt of CO_2	7.0%

7.2.3 However, it is noted that on the DECC Website (under areas identified for potential use in CCR Feasibilities Studies, available at: https://www.og.decc.gov.uk/EIP/pages/c02.htm) that the Hewett gas field (both L Bunter and U Bunter) has a capacity of 359 Mt of CO_2, and has three potential users (Damhead Creek 2 (84 Mt of CO_2), Willington C (200 Mt of CO_2) and GEC (74 Mt of CO_2)) and a remaining CO_2 storage capacity of 1 Mt of CO_2. Therefore, using the Hewett gas field with an increase in permitted generation capacity would result in its CO_2 storage capacity being exceeded.

7.2.4 Accordingly, it is proposed that the preferred CO_2 storage area for GEC is changed to the Leman gas field as this will satisfy the CO_2 storage requirement of GEC with the proposed increase in permitted generation capacity and does not have any potential users.

7.2.5 In addition, it is noted that in the future it is likely that there may be competing interest for these identified CO_2 storage areas as other CCS projects become operational. However, there are clearly a large number of additional CO_2 storage areas which exist in the same region that are capable of meeting the CO_2 storage requirement of GEC with the proposed increase in permitted generation capacity.

7.2.6 Indeed, Table 7.2 lists all the CO_2 storage areas available in the same region (the SNS) that are capable of meeting the CO_2 storage requirement of GEC with the proposed increase in permitted generation capacity which have been identified in the CCR Guidance[12].

TABLE 7.2: CO_2 STORAGE AREAS IN THE SNS REGION

Field Name	***CO_2 Storage Capacity (Mt of CO_2)***
Barque	108
Galleon	137
Hewett L Bunter	237
Hewett U Bunter	122
Indefatigable	357
Leman	1,203
Ravenspurn North	93
V Fields	143
Viking	221
Windermere	143
Total	**2,764**

7.2.7 Therefore, whilst the decision as to which specific CO_2 storage are to use will not be made until eventual implementation of CCS, Table 7.2 shows that the potential CO_2 storage areas in the region (which are capable of meeting the CO_2 storage requirement of GEC with the proposed increase in permitted generation capacity) have a total CO_2 storage capacity in excess of 2,700 Mt of CO_2. GEC with the proposed increase in permitted generation capacity will require less than 3.1 per cent of this CO_2 storage capacity over its 35 year lifetime.

7.2.8 Also discussed in the February 2010 CCR Feasibility Study was that there may be an available 'CO_2 Network' in the region such that CO_2 from GEC, and other power plants in the region, would be delivered to a 'central hub'. From this 'central hub', the captured CO_2 would be delivered to a number of different CO_2 storage areas.

7.3 Future Considerations

7.3.1 The proposed CO_2 storage area will be reviewed as part of the Status Reports.

[12] Other CO_2 storage areas with smaller CO_2 storage capacities than that required to satisfy the CO_2 storage requirements of GEC are also identified in the CCR Guidance. However, they have not been listed here.

8 TECHNICAL ASSESSMENT – CO_2 TRANSPORT

8.1.1 No additional or supplementary information is necessary / no additional or supplementary information has been requested.

9 ECONOMIC ASSESSMENT

9.1 Introduction

9.1.1 This Section presents the results of the economic assessment which investigates the feasibility of incorporating CO_2 capture technology into GEC. The economic assessment tests a number of key industry and market sensitivities.

9.1.2 This Section has been prepared by Parsons Brinckerhoff, and the assumptions used and analysis are consistent with those used in recent CCR Feasibility Studies undertaken by Parsons Brinckerhoff.

9.2 CCR Guidance Requirements

9.2.1 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 carbon capture equipment, transport and storage*".

9.2.2 Furthermore, 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 case of retrofitting and the anticipated costs of CO_2 allowances in the Community. The projections should be based on the latest evidence; review of technical options and uncertainty analysis should also be undertaken"*".

9.2.3 Accordingly, in terms of undertaking an economic 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;
- Power output with / without CO_2 capture, transport and storage;
- Lifetime load factor;
- CO_2 emitted with / without CO_2 capture, transport and storage;
- Estimations of costs of retrofitting CO_2 capture equipment (construction and operation);
- Estimations of costs of transport (construction and operation); and,
- Estimations of costs of storage (permitting and operation); and,
- Reasonable estimations of when these costs would be incurred.

9.2.4 It should be noted that the estimations of costs used in this economic assessment are based on those for CO_2 capture equipment, transport and storage based on technology available in 2014. These costs are expected to reduce in time, bearing in mind the recent and likely future developments in technology.

9.3 Approach / Assessment Methodology

9.3.1 To investigate the economic feasibility of GEC with the addition of CO_2 capture equipment, an economic model has been developed to calculate the lifetime cost of electricity, expressed in p/kWh, over an assumed 25 year economic lifetime of GEC[13].

9.3.2 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.

9.3.3 Using the economic model, the economic feasibility of GEC 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 €200/t CO_2 in €33/t CO_2 increments. This allowed for the identification of the carbon price where GEC with CO_2 capture equipment, transport and storage would become economically feasible.

9.3.4 The approach / assessment methodology is shown in Insert 9.1.

[13] This is different to the assumed 35 year technical lifetime of GEC, and has been used in the economic assessment of GEC to present a worst case assessment.

INSERT 9.1: ECONOMIC ASSESSMENT METHODOLOGY

Step 1

- The economic model calculates the cost of electricity generation (p/kWh) over the lifetime of the proposed development without the addition of CO_2 capture technology, transport and storage.
- This assumes that allowances must be purchased for 100 per cent of the residual CO_2 emissions.

Step 2

- The economic model calculates the costs of electricity generation (p/kWh) over the lifetime of the proposed development with the addition of CO_2 capture technology, transport and storage (for a number of different Scenarios).
- Again, this assumes that allowances must be purchased for 100 per cent of the residual CO_2 emissions.

Step 3

- The Base Case assumptions are subjected to a sensitivity analysis to identify potential ranges for the carbon price for the different Scenarios.

Step 4

- The range of costs of electricity generation (p/kWh) for the different Scenarios are plotted graphically to present the range of carbon prices within which retrofitting of CO_2 capture technology, transport and storage would be economically feasible.

9.4 Estimations / Assumptions

9.4.1 The main estimations and assumptions made in the economic assessment are detailed in Table 9.1.

TABLE 9.1: BASE CASE ESTIMATIONS / ASSUMPTIONS

Variable	***Assumption***
Assumed First Year of Operation	2020
£:€ Exchange Rate[14]	1.264
Nominal Discount Rate	10%
Gas Price	73.8 p/therm[15]
Carbon Allocations	None for Power Sector – Full Purchase
Power Output Impact of Carbon Capture, Transportation and Storage :	
Net Power Output of GEC	1,250 MW
Net Power Output of GEC with steam extraction for the CO_2 capture technology	1,150 MW
Lifetime load factor of GEC	75%
CO_2 emitted by GEC before fitting CO_2 capture technology	Approximately 350 kg/MWh
CO_2 emitted by GEC after fitting CO_2 capture technology	Approximately 35 kg/MWh

9.5 Economic Assessment Scenarios

9.5.1 The economic model runs three possible scenarios relating to the readiness level of the CO_2 capture technology and the possible transport and storage infrastructure options. These three possible scenarios are:

- <u>Scenario A: First of a Kind Plant, with dedicated Transport and Storage</u>

  Scenario A assumes that the CCGT power plant will be the first to be fitted with CO_2 capture equipment, transport and storage amongst the CCR CCGT power plant fleet. This means that the construction cost will be relatively high because of the lack of experience.

  In addition, within Scenario A, it is assumed that all of the onshore and offshore transport and storage infrastructure will be based on new assets. This infrastructure will be sized to GEC and would be 'dedicated'.

- <u>Scenario B: First of a Kind Plant, with dedicated Transport and Reused Storage</u>

  Similar to Scenario A, Scenario B assumes that the CCGT power plant will be the first to be fitted with CO_2 capture equipment, transport and storage amongst the CCR CCGT power plant fleet. This means that the construction cost will be relatively high because of the lack of experience.

  Scenario B assumes that the storage infrastructure can be re-used, but both onshore and offshore transport pipelines are based on new assets would be sized to GEC. Storage site re-use will allow for a reduction in storage costs.

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[14] Exchange rate taken on 26 October, 2009.
[15] Source: Central Scenario of "DECC Fossil Fuel Price Projections", DECC, July 2013.

- Scenario C: Nth of a Kind Plant, with shared Transport and Storage

  Scenario C assumes that the CCGT power plant will be fitted with CO_2 capture equipment, transport and storage after the majority of the CCR CCGT power plant fleet. This means that the construction cost will be relatively lower due to learning curve effects.

  Within Scenario C, it is assumed that a CO_2 network with several other emitters will be used. To recognise this possibility, the economic model has been run for a case where the transport and storage system (and associated costs) is shared[16]. Associated costs allocated to GEC have been assumed to be approximately 16 per cent in this economic assessment.

9.6 Sensitivity Analysis

9.6.1 For each Scenario, the economic model has the capability to vary the three sensitivities listed below:

- Discount Rate

  Whilst a nominal 10 per cent discount rate is considered to be a reasonable value for a base case analysis for a CCGT power plant project, the retrofitting of CO_2 capture equipment, transport and storage at some time in the future is considered to present an additional risk to developers. Therefore, a higher risk- adjusted discount rate of 12.5 per cent has been added to reflect this risk.

- Gas Price

  Volatility in the gas market (assuming continued linkage with oil) in the UK in recent years has shown that there remains significant uncertainty in the longer term forward gas price. Therefore, the economic assessment has modelled what is considered to be outlying possibilities for the gas price with a ±30 per cent uncertainty range.

- Capital Cost

  The capital cost for GEC has been stressed with a ±10 per cent uncertainty range. This uncertainty is applied to GEC itself and the CO_2 capture equipment, transport and storage.

9.6.2 Based on these three sensitivities, the economic model runs illustrated in this economic assessment show the cumulative effects of factors increasing the cost of electricity (high gas price, high capital cost, high discount rate), and of factors decreasing the cost of electricity (low gas price, low capital cost). Accordingly, Table 9.2 describes the high and low sensitivity runs for each Scenario.

TABLE 9.2: SENSITIVITY ANALYSIS RUNS

	Discount Rate	*Gas Price*	*Capital Costs*
High	12.5 %	+30 %	+10 %
Low	10 %	-30 %	-10 %

9.7 Economic Assessment

9.7.1 The results of the economic assessment are shown in Insert 9.2 and Insert 9.3.

9.7.2 The carbon price is shown along the x-axis and the lifetime cost of electricity (in p/kWh) is shown along the y-axis. Solid lines represent the Base Case of each Scenario and dotted lines represent the upper and lower limits of the sensitivity analysis runs.

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[16] Whilst the CCR Guidance states that outsourcing transport and storage cannot be assumed in a CCR Feasibility Study, such an option is included for comparative purposes.

9.7.3 Insert 9.2 compares the results of the economic model for GEC (black line) with Scenario A (purple line) and Scenario B (red line). Insert 9.2 shows that:

- In the economic model for GEC (black line), the lifetime cost of electricity ranges between 5.96 p/kWh (at €0/t CO_2) and 9.98 p/kWh (at €200/t CO_2);
- In the economic model for Scenario A (purple line), the lifetime cost of electricity ranges between 8.63 p/kWh (at €0/t CO_2) and 9.03 p/kWh (at €200/t CO_2); and,
- In the economic model for Scenario B (red line), the lifetime cost of electricity ranges between 8.50 p/kWh (at €0/t CO_2) and 8.91 p/kWh (at €200/t CO_2).

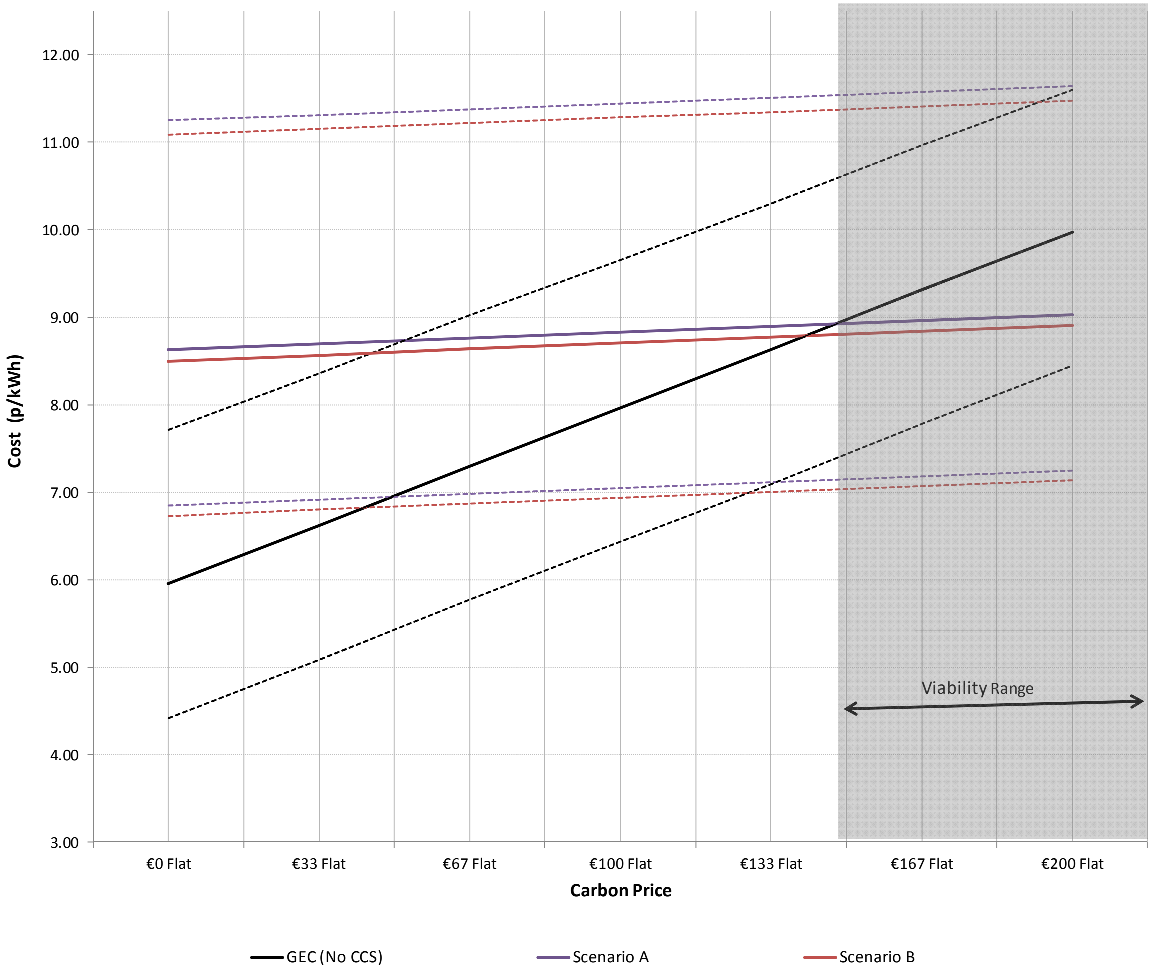
9.7.4 Therefore, under the Base Case, the break even carbon price such that the cost of electricity for GEC under Scenario A remains the same value as that for GEC (without CO_2 capture equipment, transport and storage) is approximately €150/t CO_2. Furthermore, the break even carbon price for GEC under Scenario B only decreases by a few €/t CO_2.

9.7.5 Insert 9.3 compares the results of the economic model for GEC (black line) with Scenario C (green line). Insert 9.3 shows that:

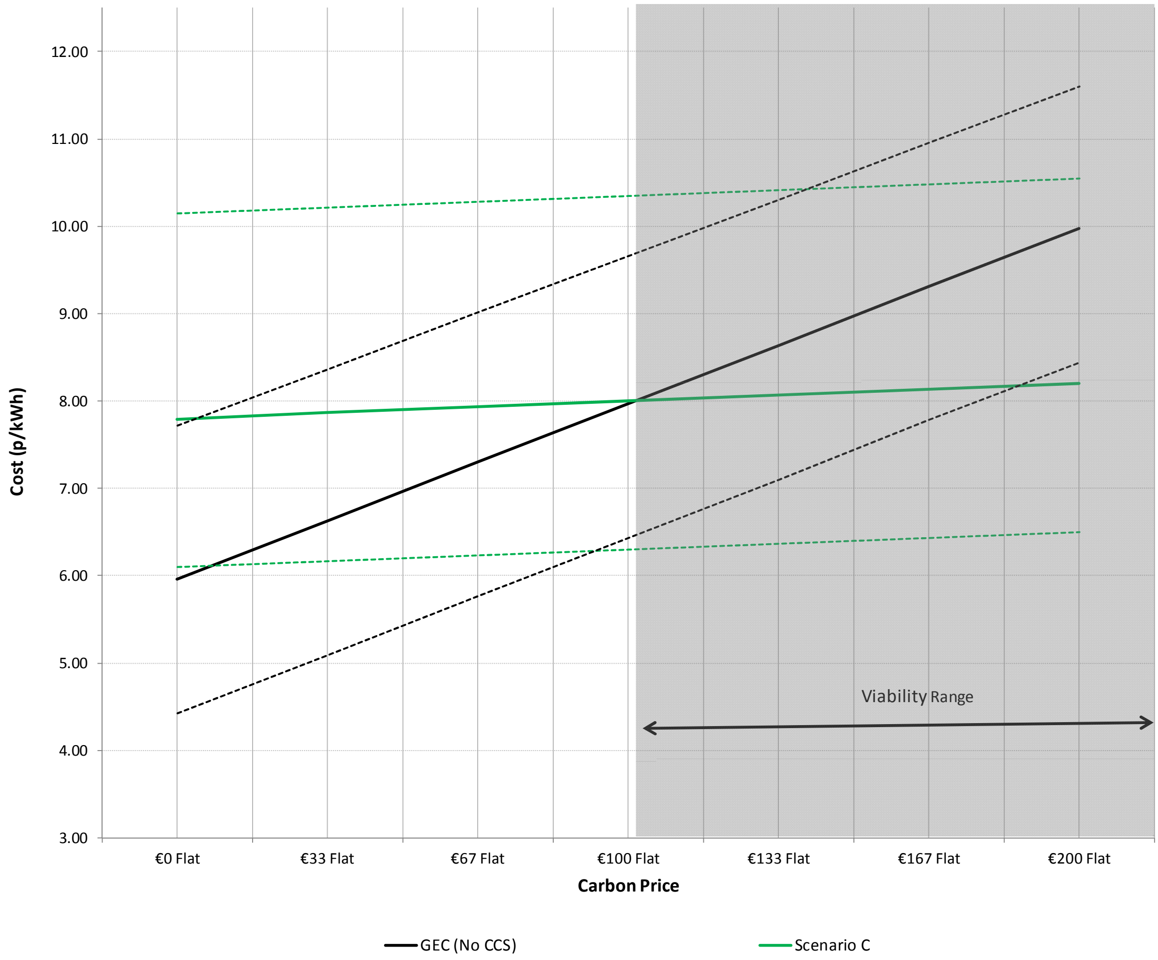
- In the economic model for GEC (black line), the lifetime cost of electricity ranges between 5.96 p/kWh (at €0/t CO_2) and 9.98 p/kWh (at €200/t CO_2); and,
- In the economic model for Scenario C (green line), the lifetime cost of electricity ranges between 7.80 p/kWh (at €0/t CO_2) and 8.20 p/kWh (at €200/t CO_2).

9.7.6 Therefore, under the Base Case, the break even carbon price such that the cost of electricity for GEC under Scenario C remains the same value as that for GEC (without CO_2 capture equipment, transport and storage) is approximately €105/t CO_2.

INSERT 9.2: ECONOMIC MODEL FOR GEC COMPARED WITH SCENARIO A AND SCENARIO B



INSERT 9.3: ECONOMIC MODEL FOR GEC COMPARED WITH SCENARIO C



9.8 Impact of Capacity Factor

9.8.1 The assumed capacity factor of 75% for GEC has an impact on the cost of electricity. If the capacity factor is adjusted to 100%, then in the economic model for GEC, the lifetime cost of electricity ranges between 5.68 p/kWh (at €0/t CO_2) and 9.70 p/kWh (at €200/t CO_2).

9.8.2 In addition, if the capacity factor is adjusted to 100%:

- Under Scenario A, the break even carbon price such that the cost of electricity for GEC under Scenario A remains the same as that for GEC (without CO_2 capture equipment, transport and storage) would drop to approximately €110/t CO_2; and,
- Under Scenario C, the break even carbon price such that the cost of electricity for GEC under Scenario C remains the same as that for GEC (without CO_2 capture equipment, transport and storage) would drop to approximately €80/t CO_2.

9.9 Conclusions

9.9.1 The results of the economic assessment indicate that the retrofitting of CO_2 capture equipment, transport and storage to GEC becomes economic:

- Under Scenario A (First of a Kind Plant, with dedicated Transport and Storage) on the basis of carbon prices of approximately €150/t CO_2; and,
- Under Scenario C (Nth of a Kind Plant, with shared Transport and Storage) on the basis of carbon prices of approximately €105/t CO_2.

9.9.2 Increasing the assumed capacity factor from 75% to 100%, the results of the economic assessment indicate that the retrofitting of CO_2 capture equipment, transport and storage to GEC becomes economic:

- Under Scenario A (First of a Kind Plant, with dedicated Transport and Storage) on the basis of carbon prices of approximately €110/t CO_2; and,
- Under Scenario C (Nth of a Kind Plant, with shared Transport and Storage) on the basis of carbon prices of approximately €80/t CO_2.

9.9.3 However, it should be noted that (at the time of writing) there is currently a pattern of an increasing supply of allowances and international credits, coupled with low demand. In addition, whilst the carbon price is the result of a wide range of factors, the recent economic recession has had (and continues to have) a major impact. Indeed, in mid-2014 the EU ETS carbon price was down at around €5/t CO_2.

10 REQUIREMENT FOR HAZARDOUS SUBSTANCES CONSENT

10.1 CCR Guidance Requirement

The CCR Guidance states (at paragraph 70) that: *"Operational CCS is likely to bring onto combustion plant sites chemicals and gases which are not currently present (or not present in such quantities) on such sites. Depending on the hazard classification of these substances and the quantity present, sites with operational CCS could become subject to the Council Directive 96/82/EC, as amended by Directive 2003/105/EC, known as the Seveso II Directive. The aim of the Directive is to prevent major accidents which involved dangerous substances and limit their consequences for man and the environment. One particular requirement of the Directive is that Member States must ensure that these objectives are taken into account in their land use planning policies. The Directive is implemented in the UK by the Planning (Hazardous Substances) Act 1990 and Regulations made under the Act which include the Planning (Hazardous Substances) Regulations 1992".*

10.1.1 Furthermore, the CCR Guidance states (at paragraph 71) that: *"One of the consequences of operating a site at which hazardous substances (currently classified as such under the Planning (Hazardous Substances) Regulations 1992) are present is the need to obtain* [Hazardous Substances Consent] *HSC".*

10.1.2 Therefore, if an applicant's proposals for operational CCS involve the storage or use on site of substances currently classified under Schedule 1 of the Regulations, it may be necessary to apply for HSC at the same time as applying for initial Consent.

10.2 Previous Findings of the February 2010 CCR Feasibility Study

10.2.1 In the February 2010 CCR Feasibility Study, the assessments were based on an assumption of post-combustion capture via chemical absorption using an amine solvent, with the named solvent being MEA.

10.2.2 In terms of a potential requirement for HSC based on MEA, the February 2010 CCR Feasibility Study concluded (at paragraph 10.2.12) that *"current knowledge of the MEA used in the* [CO_2] *capture process and of the effluent which is produced is such that, at this stage, a HSC is not required".*

10.3 Evaluation of Requirement for a HSC

10.3.1 As discussed in Section 4, the assessments in this Updated CCR Feasibility Study are based on the assumption of post-combustion capture via chemical absorption, but using an amino acid salt. The amino acid salt is a registered chemical substance with an available Material Safety Data Sheet.

10.3.2 Within the Siemens PostCap™ reference project it is noted that amino acid salts have a number of advantages when used in post-combustion CO_2 capture processes, including: that they are non-toxic; they are less sensitive to oxygen degradation; and, they have negligible vapour pressure. Indeed, due to the negligible vapour pressure practically no solvent emissions by evaporation are expected.

10.3.3 The amino acid salt that will be present on site will either be stored as a pure substance, or be used in the CO_2 capture process as a solution. These are respectively referred to as AAS Substance or AAS Preparation. In terms of the AAS Substance, the current classifications are Xi (Irritant) or R36/38 (Irritates eyes and skin). In terms of the AAS Preparation, a solution of ≥ 25 per cent of the amino acid salt will have the same classification as the AAS Substance. The amino acid salt will be stored in a dedicated area on the CO_2 capture plant site. This is shown on the illustrative site layout in Appendix B.

10.3.4 The current classifications of the AAS Substance and AAS Preparation are not included in Schedule 1 of the Regulations.

10.3.5 In addition, in terms of the emissions / effluents from the proposed CO_2 capture process, it is also not anticipated at this stage that they will be subject to any requirement for a

HSC or be subject to any on-site storage volume limits. However, appropriate disposal routes will be used (i.e. through an appropriate licenced contractor to a licensed waste management facility) to prevent any build-up of effluents on site.

10.3.6 Therefore on the assumption of post-combustion capture via chemical absorption using an amino acid salt, current knowledge of the AAS Substance / AAS Preparation used in the CO_2 capture process and of the emissions / effluents produced is such that, at this stage, a HSC is not required.

10.4 Future Considerations

10.4.1 The requirement for a HSC will be reviewed as part of the Status Reports. These Status Reports will provide an opportunity for reassessment / review of the above, particularly regarding developments / changes in classifications / CO_2 capture technologies.

11 CONCLUSIONS

11.1.1 GECL is submitting an application to the Secretary of State for the Original Consent to be varied so as to allow an increase in the permitted generation capacity of GEC from about 900 MW[17] to up to 1250 MW (the Variation Application). The increase in permitted generation capacity would enable the use of the latest turbine technologies, including the Alstom GT26 (Amended), General Electric (GE) Flex 50, Mitsubishi Heavy Industries (MHI) and the Siemens SGT5-8000H machines. InterGen has selected Siemens as its preferred supplier and is expected to install two SGT5-8000H machines on the GEC site.

11.1.2 To accompany the Variation Application, GECL is providing the following information to DECC:

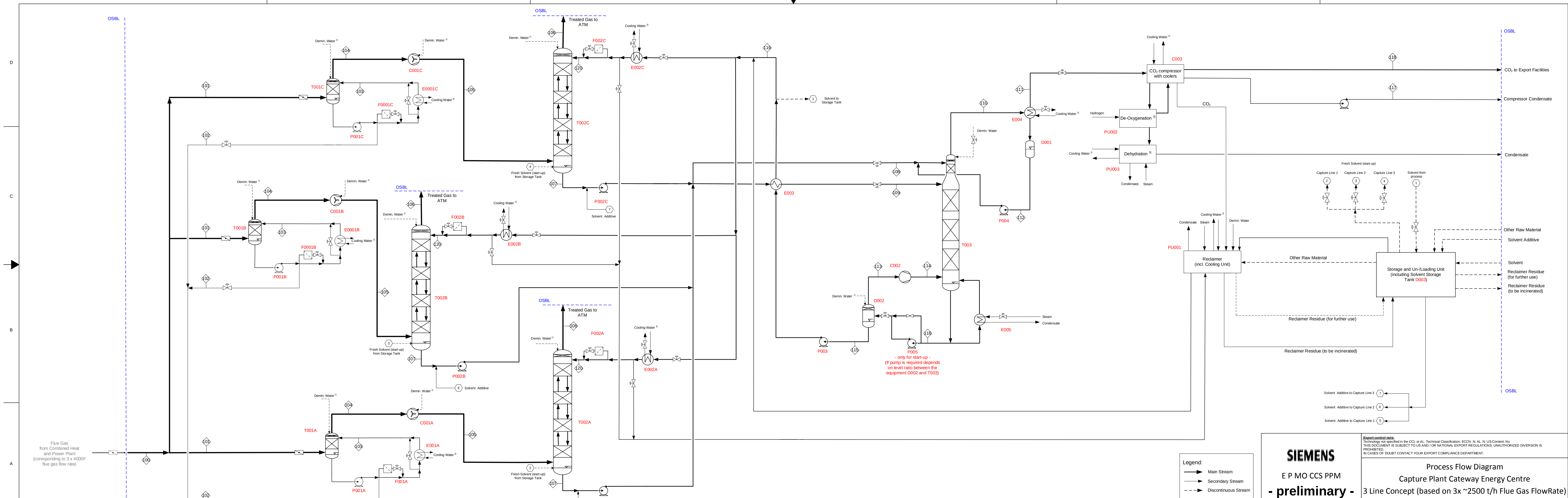
- An Updated Environmental Statement Further Information Document (the August 2014 ES FID), which includes (amongst other items):
  - A comparison between the turbine technologies considered, and thus the rationale for proposing that the Original Consent is varied;
  - An assessment of whether the likely significant effects on the environment of the Proposed Development differ from those described in the February 2010 ES and the December 2010 ES FID; and,
  - Where there is potential for the likely significant effects on the environment of the Proposed Development to differ from those described in the February 2010 ES and the December 2010 ES FID, an updated impact assessment. Where there is no potential for the likely significant effects to differ, an explanation and / or supporting information.
- This Updated CCR Feasibility Study, which includes a summary of the likely impacts on the conclusions of the 2010 CCR Feasibility Study, and an accompanying report by Imperial College London.

11.1.3 In considering the likely impacts on the conclusion of the 2010 CCR Feasibility Study, DECC and the Environment Agency noted the need to re-assess several aspects of the assessments originally provided. This Updated CCR Feasibility Study has provided this reassessment and has demonstrated that, in light of the requested for an increase in permitted generation capacity, GEC will remain fully compliant with the conclusions of the February 2010 CCR Feasibility Study and the requirements of the EU CCS Directive (and the EU IED Directive), the CCR Regulations and the CCR Guidance.

11.1.4 This Updated CCR Feasibility Study demonstrates that it remains feasible to retrofit a CCS Chain to GEC within its 35 year operating lifetime.

[17] As per the Original Consent, a tolerance of up to 5% is permitted.

APPENDIX A
ILLUSTRATIVE PROCESS SCHEMATIC



Legend:
- Main Stream
- Secondary Stream
- Discontinuous Stream

Notes:
1) Demin. Water for flushing demister in columns or vessels and blades of blower rotors
2) Cooling Water is provided by the secondary cooling system
3) Requipment of De-Oxgenation and Dehydration Unit depends on specification of CO2 purity

SIEMENS

E P MO CCS PPM

- preliminary -

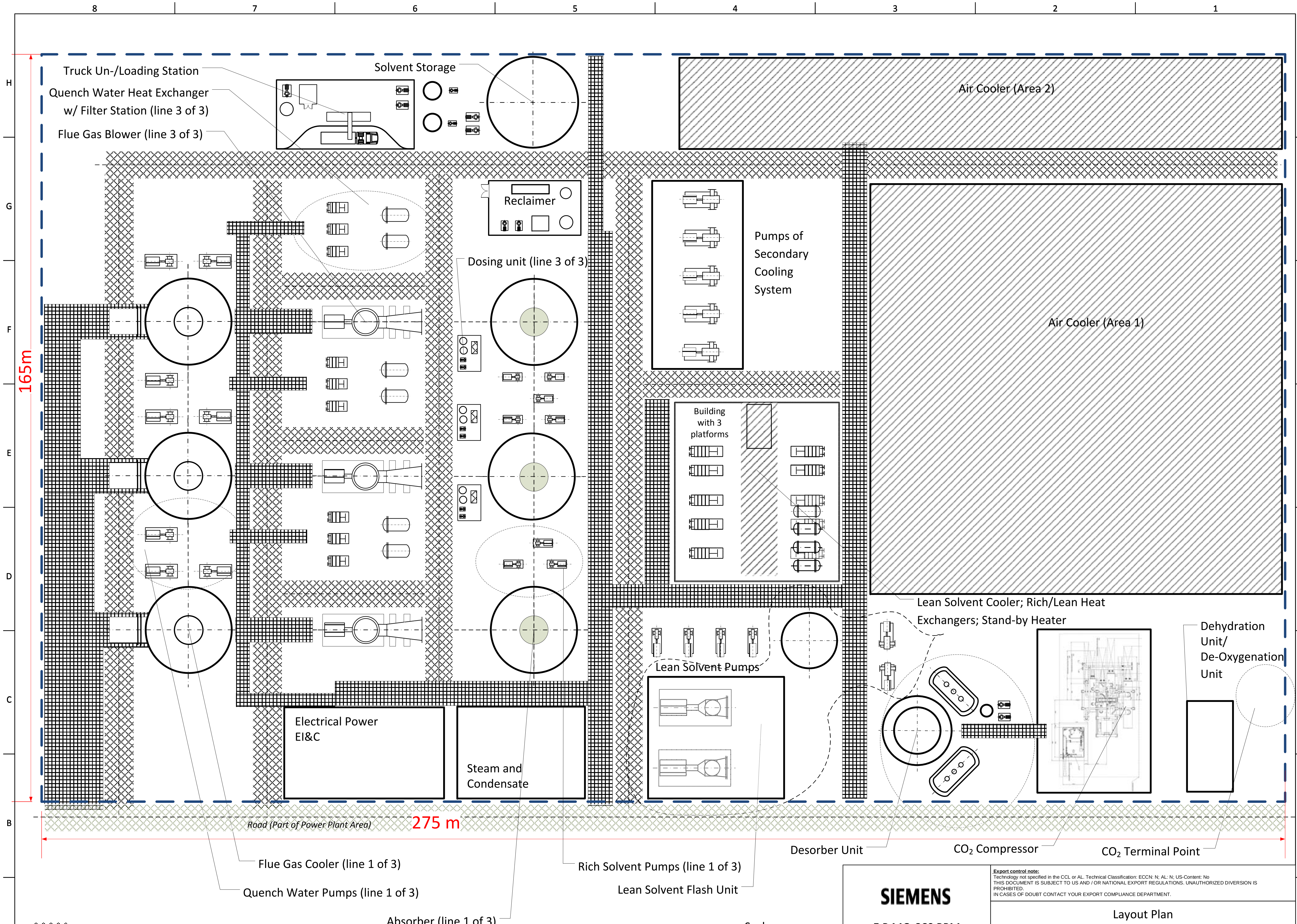
Confidential

Process Flow Diagram
Capture Plant Cateway Energy Centre
3 Line Concept (based on 3x ~2500 t/h Flue Gas FlowRate)

Size	Author	Drawing No.	REV.
	Torsten Schliepdiek		1

Scale	1:1	Date: 2014-05-27	Sheet	1 of 2

APPENDIX B
ILLUSTRATIVE SITE LAYOUT



Result:
Available CCS area: 47,100m²
Required area according to illustrated concept (275 x 165 m): 45,375 m²
Space for 3 line concept is sufficient (based on the actual engineering status)

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Layout Plan
Capture Plant Cateway Energy Centre
3 Line Concept (based on 3x~2500 t/h Flue Gas Flow Rate)

Size	Author	Drawing No.	REV.
	Torsten Schliepdiek		2
Scale 1:500	Date: 2014-06-13	Sheet	1 of 1

APPENDIX C
ANNEX C OF THE CCR GUIDANCE

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.