Peterhead CCS Project

Doc Title: FEED Summary Report for Full CCS Chain

Doc No.: **PCCS-00-MM-AA-7180-00001**
Date of issue: **22/03/2016**
Revision: **K03**
DECC Ref No: **11.133**
Knowledge Cat: **KKD - General**

KEYWORDS
Peterhead, Goldeneye, CO_2, Carbon Capture and Storage, FEED, Summary, Report, Full Chain, Technical, Risk, Cost, Decisions.

Produced by Shell U.K. Limited
ECCN: EAR 99 Deminimus

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Executive Summary

Her Majesty's Government (HMG) Autumn Statement and Statement to Markets on 25 November 2015 regarding the Carbon Capture and Storage Competition confirmed that the £1 billion ring-fenced capital budget for the Carbon Capture and Storage Competition was no longer available. This meant that the Competition could not proceed on the basis previously set out. In accordance with the agreements with DECC, the Peterhead FEED was completed as planned in December 2015. The Government and Shell are committed to sharing the knowledge from UK CCS projects, and this Key Knowledge Deliverable represents the evolution and achievement of learning throughout the Peterhead FEED and Shell's intentions for the detailed design, construction and operating phases of the project at the time of HMG's Statement to Markets.

At the time of the announcement Shell was in the process of finalising proposals for the Execute project phase for consideration in an internal Final Investment Decision (FID) gateway review. As a result the Execute project phase proposals had not yet been full formalised and approved. However, due to the status of the developed proposals at the time of the announcement, the information presented is considered to provide a good representation of the expected outcome of the FID review.

The FEED Summary Report document provides a summary of the main project elements, key learning and knowledge generated during the Front End Engineering and Design (FEED) study for the Peterhead CCS project. The scope of the document includes documentation of the FEED study outcomes as well as information on proposals for the Execute project phase.

The suite of KKDs produced as an output from the Peterhead CCS FEED study have been grouped into seven distinct categories as follows:

1. General;
2. Commercial;
3. Consents;
4. Controls;
5. Financial;
6. Technical; and
7. Subsurface.

As well as summarising the FEED study outcomes, the FEED Summary Report also provides an overview of the entire suite of Peterhead CCS KKDs with references included throughout the document to the underlying KKDs where more detailed information can be found.

The first sections of the FEED Summary Report provide an overview of the technical and subsurface aspects of the Peterhead CCS project. The technical description sections commence with presentation of a technical overview of the main chain link elements comprising the End-to-End CCS process and design status at the conclusion of the FEED study along with high level details of design parameters and the major utilities. Dedicated sections are provided for the power plant, carbon capture, compression and conditioning plant, St Fergus facilities, offshore CO_2 transportation system, Goldeneye platform, wells and subsurface elements of the overall CCS chain providing a description of the key engineering aspects associated with each of the project's technical elements.

The CCS chain link technical information is followed by an overview of full chain technical aspects such as the End-to-End process control and metering and monitoring philosophies which were developed during FEED.

The technical description sections of the report conclude with a summary of the Key Project Performance Parameters which were being developed for consideration at the Shell FID gateway review and inclusion in the Execute Project Contract with DECC. Shell was in the process of finalising the negotiations with the Execute EPC contractors and also with DECC and therefore technical aspects of the Execute design specification and associated performance guarantee figures had not yet been agreed and formalised contractually. However, due to the status of the negotiations at the time of the HMG announcement, the information presented in the PCCS FEED Summary report is considered to provide a good representation of the expected outcome of those negotiations.

Other aspects of the technical scope which are not covered within the technical sections of the report but are covered in the Technical KKDs and are detailed separately within this document include Health, Safety and Environment project aspects and Key FEED Decisions which are each summarised in a separate report section and also the process of monitoring maturation of new technologies used in the project – which is summarised within the risk management section of this report.

Key commercial aspects which are presented include a summary of the Contract Management Plan proposed for the Execute project phase which includes an outline of the intended Execute phase supply chain structure and arrangement of the main (Tier 1 and Tier 2) Execute Phase contracts. Other commercial aspects such as cost uncertainty and insurable risks are covered in the cost and risk management sections respectively.

A short summary is provided in this document detailing the permits and consents considered to be key to development of the project during FEED. Further details are provided in the separate Permits & Consents KKD. Key risks associated with permitting and consenting activities are summarised within the risk management section of this report.

Separate sections are included in this document presenting key controls aspects such as risk management, schedule and costs. The risk management section presents a summary of the key risk information under various risk categories including CCS specific risks, insurability, reuse of existing equipment and infrastructure, risk associated with obtaining permits and consents, risks which could result in schedule delays, and risks associated with the use of novel technology and the plan for maturation of such novel technology for use in the Execute phase of the project.

Summary cost estimate information is provided for both capital expenditure (CAPEX) and operating expenditure (OPEX) costs for the Execute phase of the Project. The CAPEX estimate covers the anticipated costs prior to entering operations – i.e. engineering, procurement, construction and commissioning costs. Costs during the operations period are presented in the OPEX estimate. The cost estimates provided do not include future decommissioning or abandonment costs. Information on major cost components carrying cost uncertainty is also provided along with summary descriptions of the likely range of risk and reward structures which could be applicable in the CCS supply chain. The main milestone dates defining delivery of the Execute project phase are also summarised in a separate section of this report.

Financial project aspects have been summarised where appropriate within sections of the FEED Summary report which cover topics generally covered by commercial and controls KKDs.

Finally some KKDs, including the FEED Summary Report, are given a general classification. Aspects of these KKDs covering areas such as the project organisation for FEED and Execute, the approach to stakeholder engagement, and lessons learned which were generated during FEED are also covered within the report text. In particular, a separate section is provided within this document outlining the lessons learned process followed during the FEED study with a summary provided of the key lessons which were identified by the project team as being of use to future CCS project developers.

Taken as a whole, the FEED Summary Report provides an overview of how it is anticipated that the Peterhead CCS project will be taken forward and delivered in the subsequent Execute project phase with information provided on lessons learned and experience gained from undertaking the FEED study work. Throughout the document, references are made to other FEED Key Knowledge Deliverables where more detailed information on the presented project aspects can be found.

1. Introduction

1.1. Why Peterhead CCS?

Natural Gas is presently a vital component of the EU's energy mix. The International Energy Agency's Energy Outlook 2014 makes a number of significant assertions regarding the role of gas in the world's future energy scenarios:

- Natural gas is set to play a central role in meeting the world's energy needs for at least the next two-and-a-half decades. Demand for natural gas is anticipated to grow by more than half, faster than any other fossil fuel, and become the leading fuel in the OECD (Organisation for Economic Co-operation and Development) energy mix by around 2030.
- While coal is abundant, its future use is constrained by measures to tackle pollution and reduce CO_2 emissions. Global coal demand will grow to 2040, but almost two-thirds of the increase will occur over the next ten years.
- Nuclear power will remain an essential feature of national energy strategies. But while global nuclear power capacity will increase by almost 60% to 2040, its share of global electricity generation will rise by just one percentage point to 12%.

Gas-fired power stations have lower capital costs and can operate flexibly in response to intermittent electrical power generation supply. This makes them very well suited to future electricity systems where they can complement variations in the output of renewable energy sources (e.g. wind).

Given the major role of gas in the future power sector, it is therefore important to have the option to decarbonise gas power stations to resolve the current energy policy trilemma, of achieving climate change goals, ensuring security of supply and providing value for the customer. Demonstrating Carbon Capture Storage (CCS) on a gas-fired power station is a crucial step in achieving this.

When CCS technology is applied to gas-fired plants it can deliver low-carbon electricity at lower levelised cost per MWh than when it is applied to coal-fired plants. There are also technical differences between CCS demonstration on coal and gas-fired plant, yet CCS demonstration activity globally has to-date focused on coal-fired plant. Given the rising importance of gas in the future global energy mix, Shell considers that there is a particular need to initiate gas CCS demonstration projects such as the Peterhead CCS Project.

1.2. Introduction to the Peterhead CCS Project

The Peterhead CCS Project aims to capture around one million tonnes of CO_2 per annum, over a period of 10 to 15 years, from an existing Combined Cycle Gas Turbine (CCGT) located at SSE's Peterhead Power Station in Aberdeenshire, Scotland. This would be the world's first commercial scale demonstration of post combustion CO_2 capture, transport and offshore geological storage from a gas-fired power station.

Post cessation of production, the Goldeneye gas-condensate production facility will be modified to allow the injection of dense phase CO_2 captured from the post-combustion gases of Peterhead Power Station into the depleted Goldeneye reservoir.

The CO_2 will be captured from the flue gas produced by one of the gas turbines at Peterhead Power Station (GT-13) using amine based technology provided by Cansolv (a wholly owned subsidiary of Shell). After capture, the CO_2 will be routed to a compression facility where it will be compressed, cooled and conditioned for water and oxygen removal to meet suitable transportation and storage specifications. The resulting dense phase CO_2 stream will be transported directly offshore to the wellhead platform via a new offshore pipeline which will tie-in subsea to the existing Goldeneye pipeline.

Once at the platform the CO_2 will be injected into the Goldeneye CO_2 store (a depleted hydrocarbon gas reservoir), more than 2 km under the seabed of the North Sea. The project layout is depicted in Figure 1-1 below:

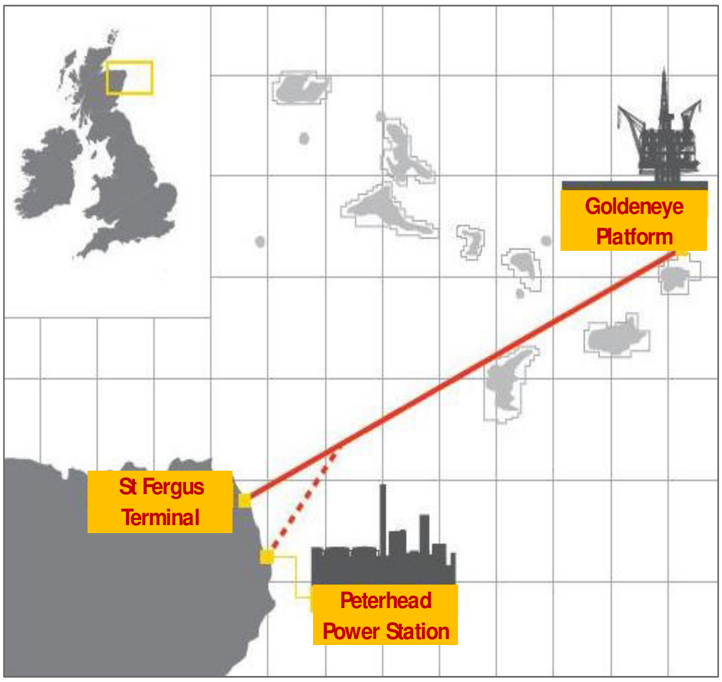


Figure 1-1: Project Location

1.3. Document Objective and Scope

This document provides a summary of the outcomes from the activities undertaken during the project's FEED phase across the full CCS Chain. Areas covered include:

- Technical aspects including coverage of:
    - Power plant modifications;
    - Carbon Capture, Compression and Conditioning plant;
    - CO_2 Pipeline Transport System;
    - Offshore Platform modifications;
    - Offshore Storage (subsurface); and
    - Full Chain CCS aspects.
- Health, Safety, Security and Environment (HSSE);
- Key Decisions;
- Key Risks;
- CCS-related Lessons Learned from FEED;
- Costs; and
- The Execute phase Contract Management Philosophy covering the main (Tier 1 and Tier 2) Sub-Contracts.

An overview of the suite of documents comprising the Peterhead CCS FEED Key Knowledge Deliverable pack is provided immediately below.

After this introduction section, an overview and timeline of the PCCS project is provided in Section 2. The End-to-End CCS Operating Philosophy is contained in Section 3 and the Key Project Parameters are included in Section 4. Key FEED Decisions, HSSE aspects and Risks are discussed in Sections 8, 5 and 6 respectively. The final report sections cover general aspects such as permits and consents, milestones, contract management and lessons learned. Further information disseminated from the Peterhead CCS FEED study is provided in other Key Knowledge Deliverables as outlined immediately below.

1.4. Overview of the Peterhead CCS Key Knowledge Deliverables

The Key Knowledge Deliverables (KKDs) which have been produced during the Peterhead CCS FEED study comprise some 45 individual documents. The KKDs have been grouped into seven distinct categories as follows:

1. General
2. Commercial
3. Consents
4. Controls
5. Financial
6. Technical
7. Subsurface

The KKDs which have been produced within each of these seven categories are summarised in the tables below. Additional summary text is also provided to describe the interrelation between the nineteen subsurface KKDs.

Table 1-1: General KKD Summary

KKD Category	DECC Deliverable Reference	Deliverable Title	Deliverable Description
General	11.019	FEED Lessons Learned Report	A summary of the financial, technical, commercial and general project learning generated from FEED with particular emphasis given to learnings related to CCS-specific aspects.
General	11.062	Project Organisation (including Roles, Responsibilities, Resourcing and Onboarding plan)	An outline of the project organisation through the FEED and Execute project phases.
General	11.063	Stakeholder and Public Engagement and Communications Plan	A description of the approach to stakeholder and public engagement and broader communications undertaken throughout FEED.

KKD Category	DECC Deliverable Reference	Deliverable Title	Deliverable Description
General	11.133	FEED Summary Report for the CCS Chain	A summary of the FEED outcomes across the full CCS chain including technical, permits and consents, financial, commercial, scheduling, and cost aspects.

Table 1-2: Commercial KKD Summary

KKD Category	DECC Deliverable Reference	Deliverable Title	Deliverable Description
Commercial	11.058	Scope of Work for Execute Contracts	A description of the technical Scope of Work to be undertaken in the main (Tier 1 and Tier 2) PCCS Execute Phase contracts.
Commercial	11.142	Risk Allocation across the Project Phase Supply Chain	A summary of the likely range of potential risk and reward structures which could be applicable across the CCS supply chain.
Commercial	11.144	Major costs components uncertainty	An overview of the major cost components with residual cost uncertainty including a description of reasons for the remaining cost uncertainty.
Commercial	11.145	Costs uncertainty mechanisms in sub contracts or supply contracts	A summary of the categories of cost components including identification of those most likely to carry cost uncertainty into the Execute Phase.
Commercial	11.146	Project Phase Supply Chain structure	A summary of the likely structure of the main (Tier 1 and Tier 2) PCCS Execute Phase contracts.
Commercial	11.148	Insurance Plan	A summary of the identified insurable Project risks with a description of the insurance options considered.

Table 1-3: Consents KKD Summary

KKD Category	DECC Deliverable Reference	Deliverable Title	Deliverable Description
Consents	11.030	Permits and Consents Register	A description of the permits and consents required throughout the design, construct, operate and decommissioning phases of the Project covering the full CCS chain.

Table 1-4: Controls KKD Summary

KKD Category	DECC Deliverable Reference	Deliverable Title	Deliverable Description
Controls	11.023	Risk Management Plan & Risk Register	A risk management plan and associated risk register capturing the Project position at the end of FEED, presenting the outcome of risks which had been identified, quantified and/or mitigated during FEED.
Controls	11.029	Project Schedule	An integrated schedule comprised of milestones, summary activities and detailed activities for the Peterhead Carbon Capture and Storage (PCCS) project covering both the FEED and Execute project phases.
Controls	11.043	Cost Estimate Report	An overview of the FEED study cost performance and a summary of the CAPEX and OPEX cost estimates for the Execute project phase.

Table 1-5: Financial KKD Summary

KKD Category	DECC Deliverable Reference	Deliverable Title	Deliverable Description
Financial	11.051	KT Open Book Financial Model	A template open book financial model containing illustrative cost data ranges based upon the work undertaken and experience gained during FEED.

KKD Category	DECC Deliverable Reference	Deliverable Title	Deliverable Description
Financial	11.143	Financial Plan change report	A summary of the significant changes made to the Project Financial Plan during FEED.
Financial	11.149	Summary of Bidder considerations in arriving at a Final Investment Decision	A summary of the considerations made in arriving at a Final Investment Decision (FID) with insights into the factors that could influence future CCS developers.

Table 1-6: Technical KKD Summary

KKD Category	DECC Deliverable Reference	Deliverable Title	Deliverable Description
Technical	11.001	Basis of Design for the CCS Chain	A high level summary of the key data on which the FEED Design was based (the input) and covering the full CCS chain.
Technical	11.003	Basic Design and Engineering Package	A Basic Design & Engineering Package covering FEED (the output) including: i) General Information; ii) Design Basis and Design Requirements; iii) Regulations, Standards & Specifications; and iv) Design Dossiers.
Technical	11.005	Operation and Maintenance Philosophy	A summary of the basis for the future operation and management of the PCCS project.
Technical	11.037	Relief, Flare and Vent Study Report	A summary of the design of the relief, flare and vent systems proposed for the project (where required), with particular focus on CO_2 relief and venting operations.
Technical	11.064	Technology Maturation Plan	A summary of the scope for application of new technology to the project capturing the maturity status at the end of FEED and any remaining plans for further maturation.

KKD Category	DECC Deliverable Reference	Deliverable Title	Deliverable Description
Technical	11.066	Site Selection Report	A summary of the site selection process and selection choices providing the rationale for the final site selection.
Technical	11.020	FEED Decision Register	A summary of the key decisions taken during FEED with supporting narrative provided for each decision presented.
Technical	11.077	Surveillance, Metering and Allocation Strategy and Design Package	A summary of the surveillance, metering and allocation provisions for the quantification and accounting of key project streams including fuel, electricity and CO_2.
Technical	11.120	Health, Safety and Environment Report	A summary of the Health, Safety, Security and Environment (HSSE) and Social Performance (SP) aspects of the project, demonstrating that a systematic approach was taken to management of Health, Safety and Environmental risks.

There are nineteen interrelated KKDs which together comprise the subsurface and well engineering technical basis for the Peterhead CCS project and its associated Storage Permit Application.

The basic geological data is described in six of the KKDs:

- 11.111 – Petrophysical Modelling Report
- 11.119 – Initial in Place Volumes Estimate;
- 11.106 – Seismic Interpretation Report;
- 11.118 – Pressure Volume Temperature Report; and
- 11.112 – Special Core Analysis Report and Geomechanics/Reactive Transport Modelling Core Analysis Reports.

The information described in these documents is used to build the Static Geological Models that are described in the Static Models Report (KKD 11.108) [1].

The Dynamic (KKD 11.122) [2], Geomechanical (KKD 11.115) [3] and Geochemical Reactivity Models (KKD 11.116) [4] are then constructed using the outputs of the Static Models. In a similar manner the collection of basic data about the existing wells in the geological structure is described in the Well Integrity Assessment (KKD 11.113) [5]. This information is combined with the results of the geological modelling and dynamic modelling to construct well designs and management plans that are described in the other seven well KKDs:

- 11.093 – Conceptual Completions and Well Intervention Design Report;
- 11.097 – Well Completion Concept Select;
- 11.098 – Well Functional Specification;
- 11.099 – Well Technical Specification;
- 11.100 – Abandonment Concept for Injection Wells;

- 11.104 – Well Operation Guidelines; and
- 11.126 – Well and Reservoir Management Plan.

An overall summary of the management plan is provided in the Storage Development Plan (KKD 11.128) [6]. This plan is augmented annually by the Annual Storage Report and Plan (KKD 11.127) [7]. The Annual Storage Report and Plan summarises the monitoring, facilities and injection performance in the period, places it into the context of the whole project, and outlines the detailed plan for the next year.

The relationship between the subsurface KKDs is presented in Figure 1-2 below and is summarised in Table 1-7.

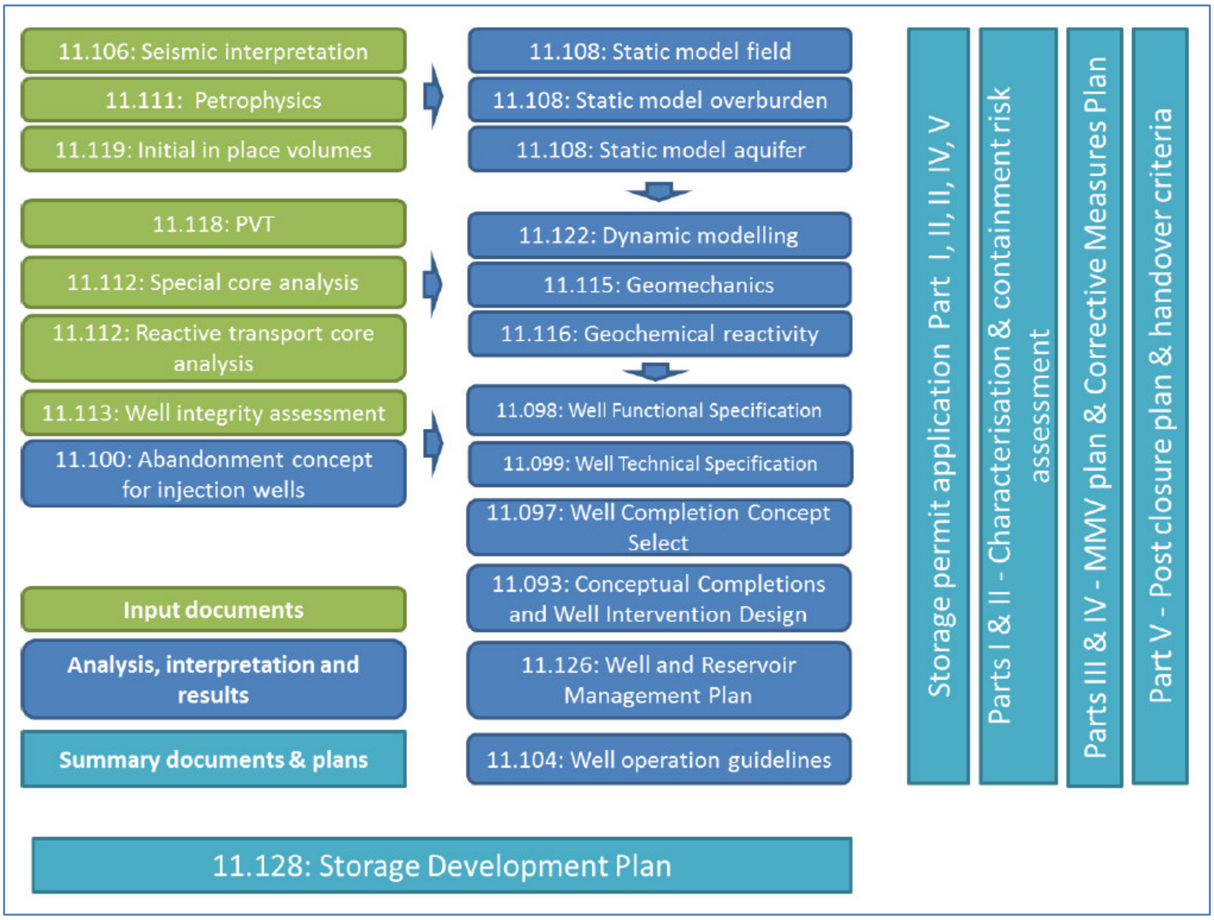


Figure 1-2: Subsurface KKD Development Flow Diagram

Table 1-7: Subsurface KKD Summary

KKD Category	DECC Deliverable Reference	Deliverable Title	Deliverable Description
Subsurface	11.093	Conceptual Completions and Well Intervention Design Report	A summary of the basis for the selection of the concept for the completions and well intervention design.

KKD Category	DECC Deliverable Reference	Deliverable Title	Deliverable Description
Subsurface	11.097	Well Completion Concept Select	A summary of the rationale for selection of the preferred completion concept.
Subsurface	11.098	Well Functional Specification	A description of the functional requirements needed for future CO_2 operations.
Subsurface	11.099	Well Technical Specification	A description of the technical requirements necessary to deliver the wells completion and achieve the functional requirements needed for operations.
Subsurface	11.104	Well Operation Guidelines	A summary of the proposed well operation guidelines covering steady state injection, transient operations for close-in and start-up, and well completion and conversion to CO_2 use.
Subsurface	11.106	Seismic Interpretation Report	A report documenting the geophysical work carried out to characterise the Goldeneye storage complex in support of assessing the storage capacity of the reservoir and the identification of any potential leak paths to the surface.
Subsurface	11.108	Static Model reports	A summary of the static earth modelling performed in support of the CO_2 storage capacity, injectivity and containment assessment.
Subsurface	11.111	Petrophysical Modelling Report	A report documenting the petrophysical work carried out to characterise the Goldeneye storage complex reservoir properties and fluid contacts in support of assessing the volumetrics and fluid behaviour within the store.
Subsurface	11.112	Special Core Analysis (SCAL) and Geomech / Reactive Transport Modelling (RTM) Core Analysis Reports	A summary of the core analysis reports which provide key information for the reservoir modelling activities and management of the Goldeneye storage reservoir.
Subsurface	11.113	Well Integrity Assessment Report	A summary of the status of the exploration and appraisal wells in the Goldeneye area of interest including consideration of the ability of the

KKD Category	DECC Deliverable Reference	Deliverable Title	Deliverable Description
			proposed CO_2 injection wells to function effectively and safely within the defined operating envelope.
Subsurface	11.115	Geomechanics Report	A report describing the investigation undertaken into formation stress states, and how past and future reservoir operations (drilling, production and CO_2 injection) could impact on the integrity of the Goldeneye storage site.
Subsurface	11.116	Geochemical Reactivity Report	A report summarising the outcome of the modelling work simulating the geochemical and mineralogical changes within the Goldeneye reservoir as a result of CO_2 injection activities.
Subsurface	11.118	Pressure Volume Temperature Report	A report summarising the pressure, volume and temperature characterisation used to model the phase behaviour of CO_2 injection into the Goldeneye reservoir.
Subsurface	11.119	Initial In Place Volumes Estimate Report	A report summarising the estimated static volumetric range for hydrocarbons in place in the Goldeneye reservoir.
Subsurface	11.122	Dynamic Reservoir Modelling Report	A report summarising the reservoir dynamic models used in the project.
Subsurface	11.126	Well and Reservoir Management Plan	A report defining the activities required to implement the well and reservoir management strategy.
Subsurface	11.127	Annual Field Storage Report and Plan	A report written to demonstrate that all activities, resources, threats and opportunities for improvement to a facility's technical integrity have been fully evaluated and quantified.
Subsurface	11.128	Storage Development Plan	A report describing where it is planned to store injected CO_2 along with information on the surface location offshore and surface facilities.
Subsurface	11.100	Abandonment Concept for Injection Wells	A summary of the abandonment concept for the project including a review of the abandonment options available.

2. Project Design

2.1. Overview

The Peterhead CCS Project aims to capture around one million tonnes of CO_2 per annum, over a period of up to 15 years, from an existing combined cycle gas turbine (CCGT) unit located at SSE's Peterhead Power Station in Aberdeenshire, Scotland. The Goldeneye gas-condensate production facility has already ceased production. Under the PCCS Project, the offshore facility will be modified to allow the injection of dense phase CO_2 into the depleted Goldeneye reservoir.

The CO_2 will be captured from the flue gas produced by one of the gas turbines at Peterhead Power Station (GT-13) using amine-based technology provided by Cansolv Technologies Inc. (Cansolv) – a wholly-owned subsidiary of Royal Dutch Shell. After capture the CO_2 will be routed to a compression facility, also located at the Peterhead site, where it will be compressed to dense phase, cooled and conditioned for water and oxygen removal to meet suitable transportation and storage specifications. The resulting dense phase CO_2 stream will be transported direct offshore to the wellhead platform via a new offshore pipeline which will tie-in subsea to the existing Goldeneye to St Fergus pipeline.

Once at the Goldeneye platform the CO_2 will be injected into the Goldeneye CO_2 storage site (a depleted hydrocarbon gas reservoir), more than 2 km under the seabed of the North Sea. The project layout is depicted in Figure 1-1.

A summary of the full chain CCS process is described in the following sections. Further technical details of the equipment can be found in the document, Key Knowledge Deliverable 11.003 – Basic Design and Engineering Package (BDEP) [8], including the pressure, temperature and flow rate operating envelope for each part of the chain. These are described in detail in Sections 4, 5, 6, 7 and 8 of the BDEP and in the Heat and Material Balances in Appendices 2 & 3 of the BDEP.

The following three design cases were defined in the pre-FEED project phase and were the basis for development of the specifications of the full CCS chain during FEED. The cases were:

1. Design Load Max (maximum output from the power plant and CCCC plant during the most favourable ambient conditions at the Peterhead site);
2. Normal operation (output from the power plant and CCCC plant when operating at the reference ambient conditions); and
3. Turndown (minimum CO_2 injection flow rate for the wells).

The PCCS project covers the following distinct stages:

- Construction (including detailed engineering, procurement, construction and commissioning activities);
- Operations;
- Decommissioning or abandonment; and
- Storage verification or post closure.

The Execute phase has been defined in most detail. During FEED the selected preferred contracting strategy for Execute was to develop the Engineering, Procurement, Construction and Commissioning scopes under separate work packages, with the major construction scopes managed under EPC contracts with overall project management provided by a Shell Project Management Team. Outline arrangements have been developed for the operations and decommissioning stages. These arrangements will be reviewed in more detail during the Execute phase.

Based on the assumption that the main Execute contracts will be awarded early in 2016, the anticipated timescale for the Peterhead CCS project is shown schematically in Figure 2-1 below. Note that the OPEX costs presented later in this document consider offshore monitoring activities after completion of both PCCS operations and decommissioning activities until 2041.

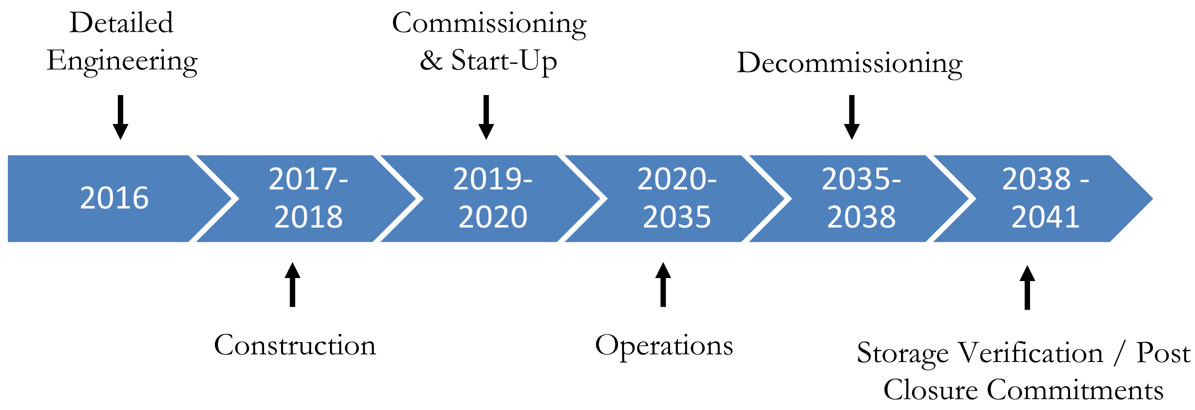


Figure 2-1: Peterhead CCS project Execute Phase Timeline

The technical content presented in this document reflects a snapshot taken at the end of the overall PCCS FEED Phase. Some elements of the technical scope have been updated during the Execution Preparation Phase after the majority of the design deliverables were issued, so the latest information in this document is not always consistent with the design dossiers included in the Appendices of the Key Knowledge Deliverable 11.003 – Basic Design and Engineering Package [8]. The design dossiers that are affected are annotated in their respective Appendix contents listing. The areas of continued design development in the Execution Preparation Phase will be addressed during Detailed Design in the Execute phase of the Project. The main areas in this category are as follows:

- Waste Water Treatment Plant simplification;
- Gas Turbine Upgrades;
- GT13 275kV Export Cable replacement;
- Oxygen Removal Specification <5ppm in CO_2;
- Revised CO_2 Tracer using Xenon isotopes; and
- Contract for Difference (CfD) and EU Emissions Trading Scheme (EU ETS) specific metering.

The waste water treatment plant design proposed at the end of FEED is described in Section 6.8 of the Key Knowledge Deliverable 11.003 – Basic Design and Engineering Package [8]. Further information is also provided in the Key Knowledge Deliverable 11.020 – FEED Decision Register [9].

The Engineering FEED was not based upon implementation of the gas turbine upgrades and therefore the technical information included in APPENDIX 2 of the Key Knowledge Deliverable 11.003 – Basic Design and Engineering Package [8] does not reflect the position at the end of FEED. Further information can be found in the Key Knowledge Deliverable 11.020 – FEED Decision Register [9]. Updates to the FEED technical documents to reflect this change will be undertaken during the Execute phase of the project. Engineering of the replacement of the GT13 275 kV export cable required to facilitate the GT upgrade will also be undertaken during the Execute phase.

Further information on the oxygen removal specification and revised CO_2 tracer can be found in the Key Knowledge Deliverable 11.064 – Technology Maturation Plan [10]. Information on the CfD and EU ETS metering requirements can be found in the Key Knowledge Deliverable 11.077 – Surveillance, Metering, Allocation Strategy and Design Package [11].

2.2. Power Plant

2.2.1. Gas-Fired Power Plant

The existing Peterhead Power Station (PPS) is owned and operated by SSE Generation Limited (SSE) and is a gas-fired Combined Cycle Gas Turbine (CCGT) power station. The station first began operating in 1982 and originally had two conventional steam-generating boilers ('Unit 1' and 'Unit 2'), which fired natural gas or oil depending on the prevailing economic conditions. These boilers were coupled to two 660 MWe Steam Turbine Generators. As a result of a major repowering project which took place in 2000, three Siemens (SGT5-4000F) gas turbines (GT) were installed, denoted GT11, GT12 and GT13, powering three new generators and raising steam through three new Heat Recovery Steam Generators (HRSG11, HRSG12 and HRSG13). The steam from all three HRSGs is routed to the original Unit 1 steam turbine (ST1). The three GTs and the common ST1 are together referred to as 'Block 1', which has a net capacity output of approximately 1180 MWe. The original steam boilers are no longer used. The 'Unit 1' boiler has been decommissioned and 'Unit 2' boiler and steam turbine unit have been mothballed and are not used.

The PCCS project will modify the present operational status of Peterhead Power Station. Flue gas from GT13 will be rerouted to the carbon capture plant instead of being directed to the existing 90 m repowering stack. A small slipstream of approximately 1 % of the total GT13 flue gas will be emitted up the 90 m repowering stack to prevent ambient air being sucked back down the chimney. Selective Catalytic Reduction (SCR) will be fitted to the existing HRSG13 to remove NO_X in the GT13 flue gas (de-NO_X) before it is transferred to the carbon capture plant.

A new steam turbine generator, denoted ST20, with an output of approximately 135 MWe will also be installed. ST20 is sized to operate in combined cycle with GT13 and will only output 135 MWe when operated in unabated mode – i.e. when the Carbon Capture Plant (CCP) is not capturing CO_2 from the GT flue gas. Under normal (CCS) operations, low pressure steam will be extracted from the turbine and supplied to the carbon capture plant process resulting in a reduced electrical output from the ST20 generator. The turbine will include suitable bypass provisions so that during start-up or in the event of a turbine trip, low pressure steam can continue to be supplied to the Carbon Capture Plant.

The Peterhead Power Station generating units export power onto Great Britain's (GB) transmission system at 275kV at the Peterhead Substation. In mainland GB, access to the transmission system is governed by National Grid Electricity Transmission (NGET) who also act as the overall Transmission System Operator (TSO). However, the local onshore transmission assets are owned and maintained by SSE Transmission, part of the SSE plc group of companies.

2.2.2. Existing Power Station Equipment

The PCCS project will make use of the existing GT13 and HRSG13 equipment at Peterhead Power Station. This also includes the existing utilities for the GT13 train equipment including the gas supply and the main electrical generator and transformer system. The existing equipment was installed in 2000, lifetime assessments have or will be carried out on the equipment and based on the outcome of the assessment the equipment will be refurbished or replaced as necessary to achieve the Project design life of 15 years.

GT13 is a Siemens SGT-4000F, formerly known as V94.3A, F-Class turbine which when the life extension works and the co-incident GT upgrades are completed, will be capable of 290 MW at site reference conditions of 8°C; 1013 mbar and 80% relative humidity when operating on outlet temperature control. HRSG13 is a standard triple pressure with reheat, natural circulation, and is of horizontal gas flow design. Mechanical ratings for High Pressure (HP) steam, Hot Reheat (HRH) steam and LP (Low Pressure) steam conditions are 165, 50 and 12 barg, and 545°C, 545°C, 265°C respectively. The cold reheat line is rated for 50 barg and 405°C. The natural gas fuel gas specification and carbon content for the gas turbine are detailed in Section 5.1 of the Key Knowledge Deliverable 11.001 – Basis of Design [12].

The new steam turbine shall be located in the existing turbine house after the demolition of the existing Unit 2 steam turbine and will be designed as far as practicable to utilise the existing foundations. The existing water cooled condensers shall be re-used by the new ST20 and parts of the existing steam and water system shall be used for the water/steam cycle between HRSG13 and the new ST20 steam turbine. The existing sea water system shall be modified to provide cooling water to the new steam turbine and the carbon capture plant. The PCCS cooling water return will be routed to the existing PPS outfall structure.

The 170 m tall stack at the power station will be modified for use as the exhaust stack for the carbon capture plant which will discharge the 'cleaned' GT13 flue gas to atmosphere after removal of its CO_2 content.

Control of the GT13/HRSG13 train and the new ST20 steam turbine will be from the existing Peterhead Power Station control room but the control system will have to be reconfigured to segregate them from the other two CCGTs which will continue to be available to generate electricity in unabated mode.

The existing power plant utilities infrastructure will provide towns water; fire-water and demineralised water for use in the carbon capture plant - reducing the amount of infrastructure which requires to be constructed to support PCCS operations.

Figure 2-2: Peterhead Power Station

2.2.3. New Power Plant Equipment

The installation of a new steam turbine generator, circa 135 MWe capability, will be carried out in order to maximise the clean electricity output of the PCCS associated generation facilities, and to allow extraction of low pressure steam for use by the carbon capture plant in as efficient a way as possible. The new steam turbine shall utilise the existing Unit 2 steam turbine electrical export circuit as far as possible.

The existing water-cooled condensers shall be re-used by the new ST20 and parts of the existing steam and water system shall be used for the water/steam cycle between HRSG13 and the new ST20 steam turbine. The existing sea water system shall be modified to provide cooling water to the new steam turbine and the Carbon Capture Plant. The PCCS cooling water return will be routed to the existing Peterhead Power Station's outfall structure.

The existing auxiliary boiler building will be demolished to provide space for the new capture plant. New auxiliary boilers will be installed within the power station as part of the PCCS project. The boilers will provide steam to the entire site including Medium Pressure (MP) steam to the CCP.

After implementation of the PCCS project, the existing CCGT arrangement will be redefined as follows:

- "Block 1" - comprising GT11, GT12 and ST1; and
- "Block 2" - comprising GT13 and ST20.

2.2.4. Flue Gas Specification

The specification of the flue gas exiting the HRSG after the SCR provided key information to the Carbon Capture Plant design. The PCCS FEED has therefore benefited from being able to access existing historical operational data for GT13. The flue gas specifications used to develop the CCP design for the three designed operating conditions are summarised in Table 2-1.

Table 2-1: Flue Gas Parameters

Battery Limit Conditions Gas Inlet to Capture Plant Booster Fan	Units	Normal Operation Case	Turn down	Design Load Max
Gas Inlet Flowrate	kg/s	685	512	710
CO_2 Mass Flowrate	t/h	145.5	99.9	153.1
Operating Temperature	°C	100	100	100
Operating Pressure	bara	1.013	1.013	1.040
Composition				
SO_2	ppmv dry	1.4	1.4	1
CO_2	vol %	3.82	3.51	3.88
H_2O	vol %	7.70	7.15	7.53
O_2	vol %	12.80	13.45	12.81
N_2	vol %	74.78	74.99	74.88
Ar	vol%	0.90	0.90	0.9
CO	ppmm	0	87	0
total NO_X	ppmm	1	1	1
HCl	vol %	0	0	0
HF	vol %	0	0	0
NH_3	ppmm	5	5	5
Dust Load	mg/Nm³	0	0	0

Notes:

1- **A 65% turndown is used for the CCS chain.**

2- **Design of pre-treatment unit shall be made for 5 ppmm ammonia but expected value is 2 ppmm.**

2.3. Carbon Capture, Compression and Conditioning (CCCC)

The project will capture the CO_2 from the flue gas of GT13 that has been extracted from the existing installation, downstream of HRSG13. The carbon capture plant is designed on the basis of achieving a 90 % capture efficiency, considering the mass of CO_2 leaving the capture plant for compression relative to the mass of CO_2 in the stream from the capture plant's pre-treatment system. This will abate approximately 90 % of the CO_2 normally produced by the 400 MWe (CCGT) of output (pre CCS retrofit).

The proposed design for the CO_2 capture plant comprises a pre-scrubber, a very large absorber column, a smaller amine regeneration column, also known as the CO_2 stripper, and associated pumps and heat exchangers. The capture plant uses LP steam for amine regeneration and MP steam for amine treatment in Thermal Re-claimer Units (TRUs). With the exception of power consumed in the PPS for providing cooling water to the CCCC plant, the electrical power required by the capture process will be wholly supplied from the UK grid.

The carbon capture plant has a designed duty of approximately 1 Mt CO_2 per annum and is intended to capture some 15 Mt of CO_2 during the PCCS Project's designed life of 15 years.

The CO_2 product delivered from the carbon capture plant to the compression and conditioning plant, co-located at the Peterhead Power Station, will be water saturated and will contain traces of oxygen. The produced CO_2 stream will be cooled and partly compressed before having oxygen removed via catalytic reactions with hydrogen, forming water. Water will be removed using molecular sieve technology. The conditioned CO_2 will then be compressed further to approximately 120 barg for export to the offshore transportation and storage system. Hydrogen for the oxygen removal reactor will be supplied from bottles on a tube trailer at a maximum rate of 1kg/h.

2.3.1. CCCC Plot Size

The new capture and compression facilities for the Peterhead project will have a footprint area of approximately 35,800 m^2. This covers the main construction sites such as the CO_2 Compression and Conditioning Plant, Carbon Capture Plant, Amine & Caustic Storage, Waste Water Treatment Plant and the CCS Plant Control Room highlighted in blue in Figure 2-3, where all the new equipment is shown in red. A breakdown of the locations is shown in the table below:

Table 2-2: CCCC approximate plot area

Location	Area (m^2)
A – CO_2 Compression and conditioning Plant	11000
B – Carbon Capture Plant	15000
C – Amine & Caustic Storage, CCS Plant Control Room	4000
D – Waste Water Treatment Plant	5800

Note: that there are several areas excluded in these estimates, and these include the seawater piping, seawater booster pumps, SCR, cable routes to grid substation and the CO_2 pipeline route.

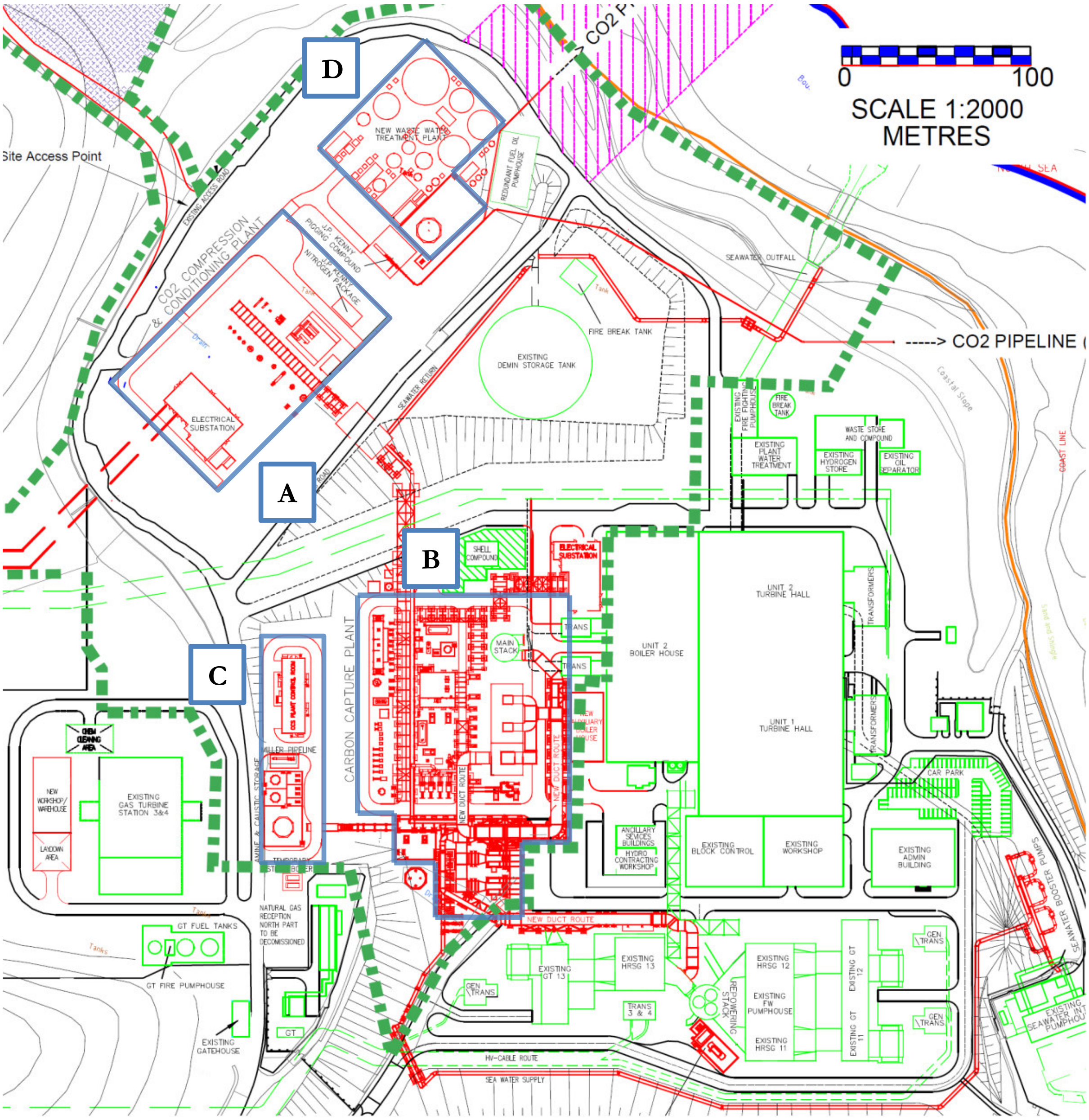


Figure 2-3: **CCCC Plot**

2.3.2. CO_2 Specification across the CCS Chain

Definition of the CO_2 specification was required at two key points across the full CCS chain in order to develop the FEED design:

1. Entry to the CO_2 Compression Plant (i.e. output of the Carbon Capture Plant post transport conditioning); and
2. Entry to the Offshore Pipeline Transmission system (i.e. output of the Compression Plant).

The operating parameters developed in FEED at these two locations is summarised in Table 2-3 and Table 2-4 respectively. A brief description of the reasons for the design limits on the significant CO_2 specification parameters is also provided in the tables. The figures quoted are for the Design Case.

Table 2-3: CCCC Plant - CO_2 Conditioning Plant Output

Parameter	Units	Details
Oxygen Removal System		
Type and description	-	
Design flow rate of CO_2	kg/h	161,887
Design flow rate of H_2	kg/h	1.0
Design pressure	bar	47.0
Design temperature	°C	-5/310 (op. 150.5)
Dehydration		
Type and description	-	Molecular Sieve
Design flowrate	kg/h	160,820
Design pressure	bar	37.9
Design temperature	°C	24
H_2O level at outlet	ppmv	<50
Filtration		
Type and description	-	Basket
Number of and duty	-	2 / 100%
Design flow rate	kg/h	160,767
Pressure drop	bar	Normal <0.1; dirty <0.5
Particulate level at outlet	Micron	< 5

Table 2-4: CO_2 Compression Plant Output (Entry to Offshore Pipeline System)

CO_2 Product (to Pipeline)	**Units**	**Value**	**Comment**
Pressure at battery Limit to Pipeline	bara	121	
Temperature at discharge of aftercooler	°C	25	
Compressor Output Flow Rate	t/h	138.3	
CO_2 Specifications	**Design Limit**	**Comments**	
H_2O	≤ 50 ppmv	Required to avoid corrosion. Should be ≤50% of the minimum saturation concentration of water in CO_2 during expected operations in pipelines and other equipment vulnerable to degradation by carbonic acid corrosion.	
O_2	≤ 5 ppmv	Required to maintain maximum concentration of 10 ppbv in formation water in the wells and avoid pitting corrosion of the 13 Cr steel pipeline material.	

CO_2 Product (to Pipeline)	Units	Value	Comment
Volatile components	≤ 0.6%		The composition of the CO_2 must be controlled to prevent operation in a region where running ductile fractures can occur. The PCCS operating philosophy is that the Goldeneye pipeline must not be operated in a region where a small crack could develop into a running ductile fracture.
H_2	≤ 0.5%		The composition of the CO_2 must be controlled to prevent operation in a region where running ductile fractures can occur.
Corrosive components	General specification		The composition of CO_2 must not adversely affect the integrity of the storage site or the relevant transport infrastructure. This covers substances such as oxides of nitrogen and sulphur, hydrochloric acid, Hg etc.
Particulates	Max size <5 microns		Specified to prevent blockage of the storage reservoir rock formation.

After the Onshore FEED design was completed, Cansolv executed a large scale pilot test of their DC201 solvent at the Technology Centre Mongstad (TCM) in Norway. The test results were positive in terms of capture efficiency and processing parameters but one new and unanticipated finding was the presence of traces of Acetaldehyde and Formaldehyde contaminants in the captured CO_2 stream. The acetaldehyde and formaldehyde concentrations expected for the Peterhead design are <95 ppmv and <0.15 ppmv respectively. These contaminants are not expected to cause any undue issues but potential impacts on the oxygen removal reactor catalyst, molecular sieve dehydration units and storage reservoir would be studied further at the start of Detailed Design.

2.3.3. Key Utilities for CCCC Plant

The CCCC plant has been designed to utilise the existing facilities at the Peterhead power plant where there is existing capacity and the integration of the utility services is practical. To increase the efficiency of the overall process low pressure steam will be extracted from the new ST20 to provide the heating requirements of the amine regeneration process.

The following table gives the specification for the main utility requirements for the Carbon Capture, Compression and Conditioning Plant:

Table 2-5: CCCC Plant Major Utilities Specification

Battery Limit Conditions	Units	Design Load Max Case	Note
Low Pressure Steam from ST20 extraction point			
▪ Pressure	bara	3.22	
▪ Temperature	°C	141	
▪ Mass Flow	kg/h	219,456	

Battery Limit Conditions	Units	Design Load Max Case	Note
LP Condensate return to ST20 water, steam cycle			
▪ Return Temperature	°C	40	
▪ Return Pressure	bara	6	
▪ Mass Flow	kg/h	216,798	20 kg/h loss
▪ Total Hardness (Ca + Mg)	ppm	as per supply	
▪ Total Dissolved Solids (TDS)	ppm	as per supply	
▪ Contaminants			
- Chloride	ppm	as per supply	
- Sulphate	ppm	as per supply	
- Sodium	ppm	as per supply	
- Iron	ppm	as per supply	
- Others (specify)		as per supply	
Medium Pressure Steam from Auxiliary boilers			
▪ Pressure	bara	21.51	
▪ Temperature	°C	236.9	
▪ Mass Flow	kg/h	4,810.3	
MP Condensate			
▪ Temperature	°C	200	
▪ Pressure	bara	16	
▪ Mass Flow	kg/h	4,810.3	Design Case is based on MP Steam
Cooling (Seawater) Supply after CW Booster Pumps			
▪ Delivery Pressure	bara	4.3	
▪ Temperature Min.	°C	5	
▪ Temperature Normal	°C	10	
▪ Temperature Max	°C	15	
▪ Mass Flow (max)	kg/h	20,328,325	
Cooling (Seawater) Return to Seawater Outfall			

Battery Limit Conditions	Units	Design Load Max Case	Note
▪ Return Pressure	bara	2.8	
▪ Temperature	°C	<27.5	
▪ Mass Flow	kg/h	20,328,325	Contains 120% margin for DCC coolers and Water Wash
Demineralised Water			
▪ Supply Temperature	°C	10	
▪ Supply Pressure	bara	-	Static head available at existing demineralised water system is estimated as 1.5 bara.
▪ Mass Flow	kg/h	54,000	Design value is used several times daily 20 minute each
▪ pH		7	
▪ Conductivity	µS/cm	<5	
▪ Hardness $CaCO_3$	mg/kg	<0.1	
▪ Contaminants			
- Chloride (Cl)	mg/kg	<0.1	
- Sulphate	ppb	To be confirmed during detailed design	
- Sodium	ppb	To be confirmed during detailed design	
- Silica (SiO_2)	mg/kg	<0.1	
Firewater			
▪ Temperature	°C	Ambient	
▪ Pressure	bara	To be confirmed during detailed design	
▪ Mass Flow	kg/h	260,000	
Service Water			
▪ Temperature	°C	10	
▪ Pressure	bara	5	
▪ Mass Flow	kg/h	25,471	
▪ Temperature	°C	Ambient	
▪ Pressure	bara	1	
▪ Mass Flow	kg/h	To be confirmed during detailed design	

Battery Limit Conditions	Units	Design Load Max Case	Note
Closed Drains			
▪ Temperature	°C	Ambient	
▪ Pressure	bara	1	
▪ Mass Flow	kg/h	To be confirmed during detailed design	
Open Drains (Stormwater) (Multiple connections)			
▪ Temperature	°C	Ambient	
▪ Pressure	bara	1	
▪ Mass Flow	kg/h	885,000	

The existing power station cooling water supply does not have enough capacity to satisfy the flowrate and pressure requirements capture, compression and conditioning plants so the modification scope includes provision of a booster pump arrangement. The optimal pumping solution could not be landed in the pre-FEED phase so a study was executed in FEED to determine the final booster pump configuration. Three x 50% booster pumps taking suction from the existing cooling water manifold was the preferred solution.

2.4. Waste Water Treatment System (U-4800)

The PCCS overall project scope includes installation of a Selective Catalytic Reduction (SCR) system within the existing HRSG13 unit. The flue gas from the HRSG is routed to the DCC for cooling from 70°C to 30°C. Due to some unavoidable ammonia slip from the SCR, the flue gas will contain traces of ammonia that dissolve into the condensed water in the DCC. The effluent from the bottom of the DCC therefore contains ammonia and needs to be treated before it can be discharged to the sea.

A second stream to be treated is the acid-wash originating from absorber C-2001. This flow contains sulphuric acid with small quantities of dissolved amine.

In addition Ion Exchange effluent is treated together with these other waste streams.

The other waste liquid effluents of the Carbon Capture plant are handled as follows:

- The rain water run-off is combined with the existing SSE drainage system;
- Dirty service and maintenance water will be discharged separately either to a local sewage system or to the power plant sewage system;
- Oily water will be discharged to the existing power plant oily water system;
- CO_2 compressor condensates are routed back to the capture process (absorber);
- Closed amine drains will be filtered and recovered back into the carbon capture process;
- Closed degraded amine drains in the TRU area will be collected and sent to the degraded amine tank for offsite disposal;
- Open chemical drains (water that might be contaminated with dilute amine, dilute chemicals) will be collected and pumped to the waste water treatment;

- Caustic drains will be collected in a local sump and removed by vacuum truck; and
- Effluent from the Thermal Reclaimer Unit is sent to the degraded amine tank for offsite disposal.

The waste water treatment system developed in FEED is presently under review and will be considered further in Detailed Design, however additional information regarding waste water treatment can be found in Section 6.8 of the Key Knowledge Deliverable 11.003 – Basic Design Engineering Package [8].

2.5. St. Fergus Facilities

2.5.1. Existing Goldeneye Facilities at St. Fergus

Modifications are required to the existing Shell-Esso Gas and Liquids (SEGAL) system terminal at St Fergus for the PCCS project. The Shell facilities at St Fergus were installed to process the hydrocarbon fluids from the Goldeneye reservoir and to store, regenerate and export Mono-Ethylene Glycol (MEG) to the Goldeneye platform via a 4" [101.6 mm] pipeline.

Methane hydrates are ice like compounds that occur worldwide in sea floor sediments on continental margins. In most offshore hydrocarbon extraction applications, hydrate formation is controlled by injection of a thermodynamic hydrate inhibitor. Methanol and MEG are common inhibitors. The existing MEG injection and storage facilities at Shell's compound within the St Fergus Terminal site, which were used for hydrate inhibition during Goldeneye hydrocarbon extraction operations, will be reused for PCCS operations. Methanol has been preferred to MEG for PCCS operations for the prevention of hydrate formation during well start-up to minimise reaction with the injected CO_2.

The main items of equipment that will be re-used and modified where necessary for the PCCS methanol system are as follows:

- Glycol Holding Tank (T-7703);
- Offshore Glycol Injection Pumps, (P-7704 A/B);
- Glycol Sump Vessel, (P-7704), and associated Glycol Sump Pump, (P-7706).

2.5.2. Modification to the Goldeneye Module at St. Fergus for PCCS

Methanol injection is required during start-up of each well for the following reasons:

1. To allow equalisation across the SSSV before opening (only when SSSV is closed);
2. To prevent hydrate formation within the injection tubing and reservoir during well start-up; and
3. To bullhead wells with high closed-in tubing head pressures (CITHPs) that can result when the well tubing is full of hydrocarbon gas.

Methanol has been preferred to MEG for PCCS operations for the prevention of hydrate formation during well start-up to minimise reaction with the injected CO_2. For PCCS, methanol injection is required intermittently whereas the existing Goldeneye MEG facilities were required to operate continuously during hydrocarbon production.

To allow provision of methanol from St Fergus the following scope of supply is required:

- Each well start-up requires a volume of up to 6.5 m^3 of methanol before the initiation of dense phase CO_2 injection. Simultaneous injection of methanol with dense phase CO_2 is not required; and
- A flow rate of approximately 4 m^3/h to 5 m^3/h was determined during FEED. This will be provided by converting the existing Goldeneye offshore glycol supply facilities at St Fergus to offshore methanol injection. The new facilities will be once through (i.e. there is no return of methanol). The existing glycol regeneration facilities are not required for PCCS. A more specific flow rate requirement will be determined in Detailed Design.

When required, methanol injection will be managed from the PCCS Control Room requested on a call-off basis. The actual Methanol operations will be carried out by the existing Shell St Fergus Terminal control room under instruction from the PCCS Control Room. Remote monitoring of methanol pumping has been included in the scope of the Peterhead CCS control room requirements.

Further information can be found in Section 2.5.5 of the Key Knowledge Deliverable 11.003 – Basic Design and Engineering Package [8].

2.6. Offshore CO_2 Transportation System

2.6.1. Overview

The PCCS Project intends to re-use the Goldeneye subsea pipeline system and the offshore facilities at Goldeneye platform for the transport, injection and storage of CO_2.

Following CO_2 capture, compression and conditioning at the PCCS Peterhead site, the CO_2 is piped to a new onshore pig launcher facility which is located in the area formerly occupied by the PPS heavy fuel oil tank farm and form there into the offshore CO_2 transportation system.

A section of new pipeline will be installed which will transport the CO_2 from the Peterhead Power Station and tie into the existing Goldeneye to St Fergus export pipeline for transport to the Goldeneye field for storage.

From the pig launcher, the pipeline is therefore routed directly offshore via a new 20” (508 mm) carbon steel pipeline approximately 900 m in length to the landfall point. The selected FEED landfall solution is construction using the trenchless installation method, horizontal directional drilling (HDD). The feasibility of the landfall design was confirmed in FEED and will be developed further in Detailed Design during the Execute phase.

En-route to the Goldeneye pipeline offshore, the new pipeline is required to cross two existing subsea pipelines: the 20” Fulmar A to St Fergus gas pipeline (PL208) and the 28” [711.2 mm] Britannia to St Fergus gas pipeline (PL1270). It is proposed the pipeline is tied in at point KP19.6 on the existing 20” carbon steel Goldeneye pipeline. An alternative tie-in location at Goldeneye KP 19.3 had also been identified and this was evaluated during FEED. However, it was deemed unsuitable as the pipeline is fully buried at that point with the 4” line strapped to it. These factors would generate a far longer and riskier offshore schedule and for those reasons was not pursued as an option.

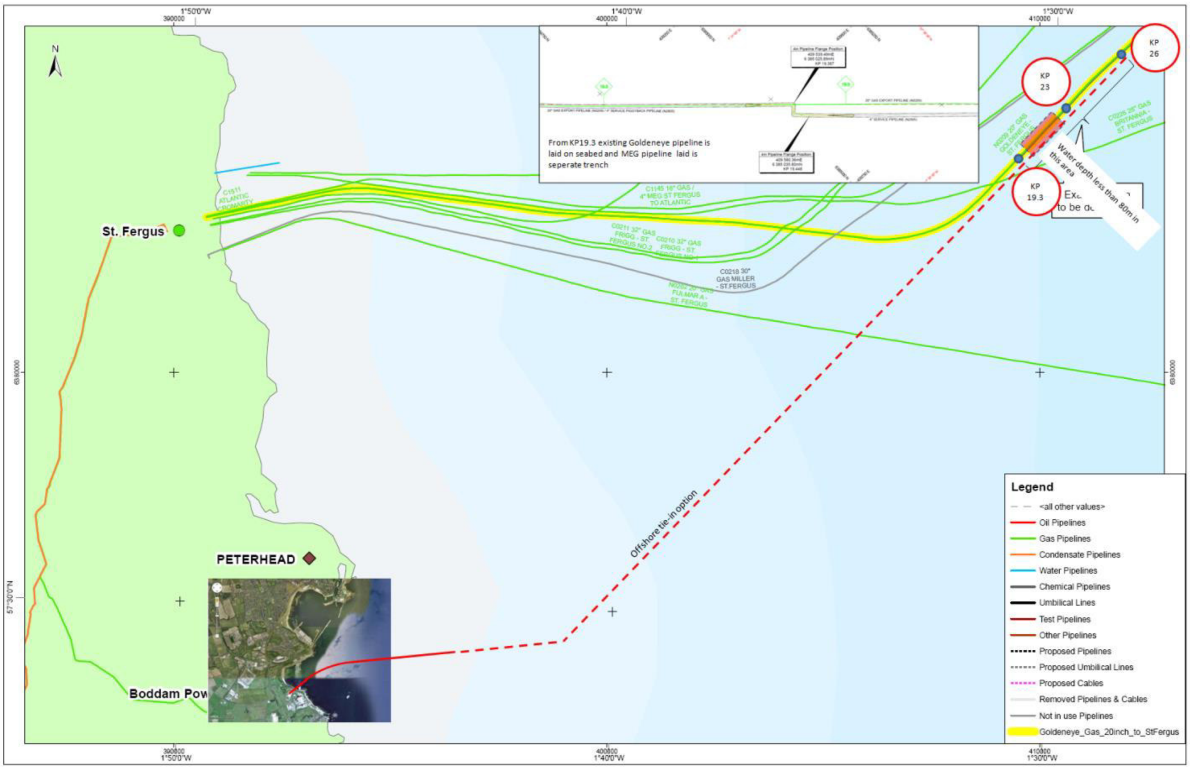


Figure 2-4: Field Layout from PPS to Goldeneye Pipeline Tie In

2.6.2. Existing Pipeline Systems

The Goldeneye pipeline was installed prior to start of operations in 2006 and operated until December 2013. The offshore pipeline and wells are currently owned by the Goldeneye Joint Venture, established to produce gas from the field under the existing production license. Production from the field has now ceased and the transfer of ownership of the assets to the Peterhead CCS Project is being progressed via a Sales and Purchase Agreement. The new and existing pipelines are described in Figure 2-4. The existing pipeline parameters can be found in Table 2-6.

Table 2-6: Existing Pipeline

Pipelines	
Length & Diameter	Length: offshore 101 km Onshore 0.6 km Main pipeline : 20" [508 mm] (OD)[1] MEG service line: 4" [101.6 mm] (NB)[2]
Onshore Arrival Pressure	Initial : 86 bara Decline to : 25 bara (minimum)
Route & Crossings	Direct from Goldeneye platform to Shell-Esso terminal at St. Fergus (parallel to and south of Miller / SAGE (Scottish Area Gas Evacuation) pipeline corridor) Five pipeline crossings

In 2013 the Goldeneye pipeline was cleaned and left filled with corrosion inhibitor and with biocide solutions, with a protection life of 7 years. The corrosion risk of the pipeline was evaluated using a Pipe RBA (Risk Based Assessment) approach. No internal intelligent inspection was performed during FEED. A decision was taken in the pre-FEED project phase that an intelligent pig run would not be carried out during FEED but would be undertaken in the Execute phase prior to entering operations. This is consistent with the pigging philosophy proposed in the earlier Longannet CCS Project FEED study.

Previous study work done during the earlier Longannet CCS Project FEED study concluded that the existing carbon steel 20" Goldeneye pipeline with external coating and cathodic protection was suitable for the transportation of dense phase CO_2 within the defined operational parameters, including maximum and minimum temperatures and CO_2 water content limits. The PCCS FEED confirmed the conclusions with no significant issues identified.

2.6.3. Landfall, Pipeline and Subsea Scope

The FEED study work concluded that the scope of work to be carried out on the subsea facilities in the project's Execute phase includes:

- New onshore pig launcher facility;
- New 900 m HDD landfall;
- New 21.6 km 20" carbon steel CO_2 export pipeline from Peterhead Power Station to a subsea tie-in to the existing 20" Goldeneye pipeline;
- New CO_2 export pipeline subsea flanged tie-in arrangement;
- New Subsea Isolation Valve (SSIV) including the associated control facilities, umbilical and Topside Umbilical Termination Unit (TUTU);
- Subsea Isolation Valve (SSIV) tie-in spools;
- Existing platform riser and spools to the upstream weld of the riser Emergency Shutdown Valve (ESDV);
- Re-use of the existing 4" carbon steel MEG pipeline from St. Fergus which has been confirmed suitable for conversion to methanol transportation.

[1] Outside diameter

[2] Nominal Bore

2.6.4. Pipeline Materials

The following sections focus on the material selection process for the new pipeline section of the offshore transportation system. The existing pipeline was designed in accordance with Shell's internal Design and Engineering Practice (DEP) standards. Shell's DEP requirements have been used in consideration of both the existing pipeline materials and also the design requirements for the new pipeline section for the PCCS project.

2.6.4.1. Mechanical Design

The 20" export pipeline will be installed and buried where necessary to provide adequate seabed stability offshore using the S-Lay construction technique. The wall thickness for the new 20" CO_2 export pipeline has been assessed during FEED for pressure containment, hydrostatic collapse and propagation buckling in accordance with the requirements of BS PD 8010. The required wall thicknesses identified for the main offshore section of the new 20" (508 mm OD) pipeline is 14.3 mm. Increased pipeline wall thickness is required at the shore crossing and for the onshore route.

2.6.4.2. Weight Coating

The FEED study specified that new 20" CO_2 export pipeline should be externally coated with steel reinforced concrete to ensure pipeline stability. In addition the pipeline will also be trenched some length to meet the pipeline stability requirements. Concrete weight coating is required to comply with Shell's DEP requirements.

2.6.4.3. Anti-Corrosion Coating

To protect the pipelines against external corrosion, an anti-corrosion coating system shall be applied. The anti-corrosion coating requirements have been selected in accordance with Shell's DEP standards.

2.6.4.4. Internal flow Coating

The existing Goldeneye pipeline was installed with an internal epoxy coating which was applied to improve flow and reduce commissioning works; it was not applied to mitigate corrosion. The internal coating is a solvent-based cured epoxy with a thickness of between 30 - 80 microns.

To date, short term testing of the coating using samples of spare coated pipe retained from Goldeneye pipeline installation has been performed and has demonstrated that the epoxy coating is resistant to dense phase CO_2 exposure and the learning from the lab analysis of pig returns from a recent hydrocarbon freeing programme confirmed no evidence of coating spalling or disbondment.

There is no requirement to internally coat the new pipeline section although shot blasting to remove mill scale and additional measures during installation and commissioning should be considered to ensure debris is minimised for mitigating filtration concerns offshore.

2.6.4.5. Water Dew Point

Special attention should be given to dewatering of pipeline system prior to filling with CO_2. Free water combined with high CO_2 pressure may give rise to extreme corrosion rates, primarily due to the formation of carbonic acid. As such the pipeline should be dried to a dew point of -40 °C at ambient pressure before filling with CO_2. As drying is to follow dewatering, there is no requirement for conditioning slugs of MEG to be incorporated into the dewatering pig train. All air injected into the pipeline during dewatering and drying operations is required to be oil free and at a dew point of -60 °C or dryer.

2.6.5. Pipeline Capacity

A feature of the already existing offshore pipeline transport system, Goldeneye platform infrastructure, offshore wells and storage reservoir is that it is anticipated to be capable of storing more CO_2 than the 15 Mt of CO_2 proposed by the PCCS Project and to be able to transport more than the proposed compressor's maximum CO_2 flow rate of 138.3 t/h. Any such proposals would be considered under a separate future project should this be required.

2.6.6. Clustering Potential

The PCCS Project considers re-use of the existing the Goldeneye pipeline and reservoir for the CO_2 transportation and storage aspects of the full chain solution. This infrastructure can potentially provide significant CO_2 transport and storage capacity over and above that required for the demonstration phase of the Peterhead CCS project.

Further capacity could be accessed if the associated infrastructure in the region and the surrounding geological formations are also considered: Spare transport capacity is expected to be available in a number of pipelines, part owned by Shell, leading from St Fergus to the main areas for CO_2 storage and Enhanced Oil Recovery (EOR) in the Northern and Central North Sea. The Goldeneye pipeline has a CO_2 carrying capacity of 8–9 Mtpa. The Miller pipeline has a capacity of over 20Mtpa.

The convergence of these pipelines on St Fergus, coupled with the Goldeneye platform storage hub, gives access to:

- The depleted Goldeneye hydrocarbon reservoir. The PCCS FEED study work gives a high level of confidence that Goldeneye has a storage capacity of at least 24Mt;
- The Captain Aquifer, which has storage capacity estimates ranging from a few hundred million tonnes to over a billion tonnes;
- The Mey sandstone member, which was assessed by the UKSAP project as having a P50 capacity of 3958 Mt;
- The Maureen (Paleogene, Montrose Group, Maureen Formation) and the Dornoch (Paleogene), Moray Group, Dornoch Formation. The P50 capacities have been assessed by the UK SAP as: Maureen: 1777 Mt; Dornoch: 506 Mt.

Subject to possible future requirements for storing additional CO_2 volumes from the Peterhead Power Station, present analyses suggests a high likelihood of there being unused capacity in the PCCS infrastructure and reservoir which could be made available for use by other third-party projects and follow on CCS Projects.

A variety of large onshore sources of CO_2 emissions have been identified, ranging from the immediate Peterhead-St Fergus catchment to the central belt of Scotland and further afield as potential candidates for the potential use of this capacity. The PCCS Project presents an opportunity subsequently to sequester future industrial CO_2 emissions from across Scotland. Information on industrial CO_2 sources can be obtained online, including from the SEPA [13] and SCCS [14] websites.

The Peterhead to Goldeneye project therefore will create the first element of a CCS transport infrastructure, and by utilising existing well characterised infrastructure does it at low cost and risk.

2.7. Goldeneye platform

The Goldeneye platform, shown in Figure 2-5, consists of a four-legged steel structure, connected to the seabed with two vertical steel piles at each corner, that supports a topsides deck structure with a helideck, pedestal crane and vent stack. The jacket and topsides were installed during 2003.

Figure 2-5: Goldeneye Platform

The topsides comprise two deck levels at elevations +22 m and +31.5 m with an intermediate mezzanine deck at elevation +27.15 m. The main plan dimensions of the decks are 31x16 m with the extra length cantilevered out to the west of the jacket, on the opposite side from the wellheads. This cantilever supports the helideck and contains the accommodation, control and equipment rooms.

The current operating weight of the topsides is approximately 1,680 tonnes but the design of the jacket structure allows for a topsides weight of up to 2,000 tonnes.

The jacket structure is a four-legged X-braced structure that was designed to be lift installed. The weight of the jacket is just less than 2,500 tonnes. Three of the jacket faces are battered with the fourth (east) face being vertical to allow the close approach of a jack-up drilling rig to access the wells. The faces of the jacket are cross-braced with perimeter plan bracing only at the top and bottom levels.

2.7.1. Existing Topsides Facilities

The platform is designed to operate as a 'Normally Unattended Installation' (NUI). It has accommodation for 12 personnel to facilitate brief maintenance campaigns. Control of the existing platform is performed from Shell's St Fergus Control Room. The existing Goldeneye facilities comprise a number of process and utility systems.

The existing platform has 8 well slots although only 5 of these were used during the hydrocarbon production phase. During hydrocarbon operations, the wells were controlled from shore using a communications links. The existing Goldeneye Offshore Platform Design Parameters are summarised below.

Table 2-7: Summary of Existing Goldeneye Offshore Platform Design Parameters

Parameter	Description
Design Concept	Full wellstream tieback to shore, for onshore processing of the gas and condensate Normally Unattended Installation (NUI) platform offshore for control of wells / chokes, manifolding, metering and water / oil detection
Field Life	c. 10 years
Design Life	20 years (to be extended under the PCCS Project)
Wells	5 jack-up drilled wells with sand exclusion
Offshore Facility	
Facility type	Normally Unattended Installation (NUI) Wellhead platform controlled from onshore (St. Fergus) Short Stay Accommodation (provided for 12 Personnel On Board (POB) normally, with fold-down beds in five of the cabins to accommodate a maximum POB of 22) for overnight stays
Water Depth	119 m (LAT)
Offshore Process/ Equipment (Platform Topsides)	Manifold, Production separator Gas, hydrocarbons liquids and water metering Water and oil detection, sand detection Provision for possible future water treatment & sand collection
Manning Requirements	Six campaign maintenance visits per year of 6-8 days duration with a crew of 12 (planned and unplanned maintenance c. 6000 man-hours per year); Additional visits are required for ad-hoc work

2.7.2. Modification to the Offshore Facilities for PCCS

For PCCS, the operational life of the Goldeneye platform will be extended from 20 years to 35 years for the purpose of injecting CO_2 into the depleted reservoir for long-term storage. During the Execute phase a lifetime assessment will be carried out and based on the outcome of the assessment the facility will be refurbished as necessary to achieve the Project design life of 15 years. The platform is generally in good condition and no major works are anticipated to be required to achieve the lifetime extension.

A number of process and piping modifications are required to adapt the platform and pipeline for this change of use. The structural scope is limited to the offshore modifications to the Goldeneye platform in order to facilitate its change in operation from gas production to receiving and injecting CO_2 into the reservoir.

With the possible exception of strengthening the vent stack support structure, there are no major structural modifications required for this change in operation. The structural scope entails verifying the integrity of the structure for the extended design life in addition to supporting the modifications required by the other engineering disciplines, i.e., provision of access to the CO_2 filters, provision of equipment support trimmers and pipe supports. The estimated weight of structural steelwork additions is circa 23 tonnes.

After the PCCS operational period and CO_2 injection is stopped, it is proposed that the platform will be decommissioned. The wells will be plugged and sealed and topsides and jacket removed so that the reservoir can be left with the CO_2 stored in perpetuity. Reservoir performance will be monitored post decommissioning by periodic boat-borne surveys.

There is the potential to either continue CO_2 injection activities beyond the proposed 15-year operating period (e.g. as a result of interest in third party access) and also to mothball rather than decommission the CCS infrastructure at the end of the operating period rather than undertaking decommissioning. These options will be reviewed as the Execute phase progresses on an 'as and when required' basis.

Further information on the Goldeneye platform and the storage facilities in general can be found in Appendix 5 of the Key Knowledge Deliverable 11.003 – Basic Design and Engineering Package [8].

2.8. Wells

Modifications required to the offshore well facilities include the topsides pipe work, new Christmas Tree, new well completions and new vents for use by the PCCS Project.

The platform has eight slots, five of which have been used during the production phase. The five production wells were suspended in 2012.

It is planned to place a heavy duty jack-up rig over the platform to re-complete the wells for CO_2 injection. The FEED study identified that only four of the five wells required to be worked over (3 wells will be used for injection and 1 well for monitoring). The fifth well (currently envisaged to be GYA-05) is planned to be abandoned.

2.8.1. Subsurface Engineering and Wells

During FEED, the five existing wells were evaluated to determine their suitability for use in CO_2 injection. Due to integrity issues and CO_2 phase behaviour management, it is not considered possible to use the wells without any modification. A rig is required to carry out a workover of the upper completion by installing smaller bore tubing in order to manage CO_2 expansion and prevent undesirable levels of thermal cycling. The lower completion installed in the Goldeneye wells (screen + gravel pack) is considered to be suitable for use for CO_2 injection without workover.

There is no intention of drilling new wells or side-track wells, nor is there the intention of performing further workovers at a later date.

The well components have been investigated during FEED to review the expected well conditions under CO_2 injection. The change of use of Goldeneye wells from hydrocarbon production to CO_2 injection has been checked against the existing well design with particular focus on the following areas:

- Materials (metallurgy and elastomers);
- Casing design; and
- Cement and pressure management.

Various systems were investigated during FEED to address the upper completion requirements for CO_2 injection including:

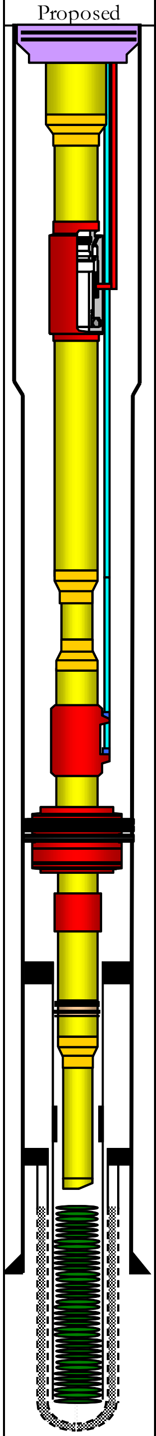
- Single tapered completion;
- Insert string;
- Dual completion;
- Concentric completion; and
- Downhole choke.

The initial installation of the single tapered completion option was identified to be the simplest and most robust solution. The other evaluated systems would present extra design and/or operational challenges and also additional cost in comparison to the selected single tapered completion. Therefore, the decision was taken in FEED to use single wells with slim tubing sizes for the upper completion.

Re-completion of the wells will incorporate changing out of the 7" [177.8 mm] tubing to a smaller size. It is proposed to standardise the top (from surface Christmas tree down to the SSSV) and the bottom (tail pipe up to the Permanent Downhole Gauge (PDG) mandrel) of the upper completion for the CO_2 injection. Distributed Temperature System (DTS) will be installed in the wells for monitoring purposes.

The FEED study concluded that all completion equipment (i.e. attached to the tubing string) requires being 13 % Chrome metallurgy (13Cr) or super 13 % Chrome metallurgy (S13Cr) equivalent metallurgy and be capable of operating at pressures in excess of the expected final well pressures.

For normal well operating conditions (injection and transient conditions) the existing wellhead system is compatible with the expected low temperatures for the PCCS CO_2 injection duty. However, the FEED study concluded that the Christmas tree and the tubing hanger require to be replaced in the workover with units having a lower minimum temperature rating than that currently installed for hydrocarbon operations in order to be sure that integrity would be maintained in the event of a CO_2 leak. The planned completion for CCS operations is shown in Figure 2-6:



GYA 01 Proposed	Depth MD (ft)	Description of Item	ID (Inches)	Drift (Inches)
	79	Tubing Hanger	6.169	
		7.00 29# Tubing 13Cr/S13Cr	6.184	6.059
	139	XO 7.00" 29# x 4 1/2" 12.6#	3.958	3.833
		4 1/2" 12.6# Tubing 13Cr/S13Cr	3.958	3.833
	2500	SCTRSSSV 4 1/2" 13cr	3.813	
	3130	Casing XO 10 3/4" x 9 5/8"		
	6800	XO 4 1/2" 12.6# x 3 1/2"	2.922	
		3 1/2" Tubing	2.922	
	8430	X/O/Wire Finder Trip Sub 3 1/2" x 4 1/2" 12.6#	2.992	2.787
	8536	4 1/2" PDGM for PDG + DTS	3.958	3.833
		4 1/2" 12.6 # Tubing	3.958	3.833
	8596	9 5/8" x 4 1/2" Packer	3.818	
		4 1/2" Circulating/Pressure Relief Device	3.958	3.833
		4 1/2" Tubing		
	8696	Baker SC-2R packer/screen hanger 13Cr (existing)		
		G22 Seal Assembly	3.958	3.833
	8650	XO 4 1/2" 12.6# x 2 7/8" 6.4# FJ Tubing	2.441	2.347
	8755	Schlumberger FIV (existing)	2.94"	
	8850	2 7/8" Mule Shoe		
	8952	Top of 4.00" Screens (existing)	3.548	

Figure 2-6: Proposed general completion.

Further detail on the technical and functional specification of the wells can be found in Key Knowledge Deliverable 11.099 – Well Technical Specification [15] and Key Knowledge Deliverable 11.098 – Well Functional Specification [16]. Temperature and Pressure modelling can be found in the Key Knowledge Deliverable 11.118 – Pressure, Volume and Temperature (PVT) Report [17].

2.8.2. Storage Site

The PCCS storage site is based upon the use of the Goldeneye gas condensate field as the primary storage container for the CO_2 capture from the flue gas of GT13 at Peterhead Power Station.

The Goldeneye field is located in the Outer Moray Firth, circa 100 km north-east of the St Fergus gas plant, mainly in UKCS blocks 14/29a (Offshore Hydrocarbon Production License P257) and 20/4b (License P592) but is mapped to also straddle blocks 14/28b (License P732) and 20/3b (License P739). It is defined as the pore volume between the mapped top of the Kimmeridge Clay Formation and the mapped top of the Captain Sandstone Member that exists within an area bounded by a polygon that lies a short distance beyond the Original Oil-Water-Contact (OOWC) of the Goldeneye field. The extent of the Goldeneye storage complex is shown in Figure 2-7. Porous and permeable lithologies exist within the Scapa Sandstone, Yawl Sandstone and Captain Sandstone Members. The last named of these acts as the hydrocarbon reservoir of the Goldeneye field.

The storage complex includes the storage site, defined above, and the following additional elements – also shown schematically in Figure 2-8 and Figure 2-9.

- Storage seal – The storage seal comprises all of the stratigraphic units between the top of the Captain Sandstone Member and the top of the Plenus Marl Bed (including the Upper Valhall Member and Rødby Formation – both part of the Cromer Knoll Group – and the Hidra Formation and Plenus Marl Bed – both part of the Chalk Group.
- Secondary containment (hydraulically connected) – It is intended that the hydraulically connected secondary storage will accommodate migration of CO_2 within the reservoir formation but beyond the licensed boundary of the storage site. As such, it is represented by the lateral extension of the permeable formations that make up the storage site.
- Secondary containment (overburden) – The secondary storage (overburden) will accommodate any migration of CO_2 that escapes vertically beyond the storage seal. To contain this migrated volume, the secondary containment requires having a secondary (or complex) seal. The secondary storage (overburden) for the Goldeneye field includes the Chalk Group above the top of the Plenus Marl Bed, the Montrose Group (particularly the Mey Sandstone Member) and the lower Dornoch sandstone, within the Moray Group.
- Complex seal – The mudstone at the top of the Lista Formation (which is referred to in this report as the Lista mudstone and is of Palaeocene age) within the Montrose Group, and the Dornoch mudstone, part of the Palaeocene to Eocene-aged Dornoch Formation in the Moray Group, acts as the complex seal.

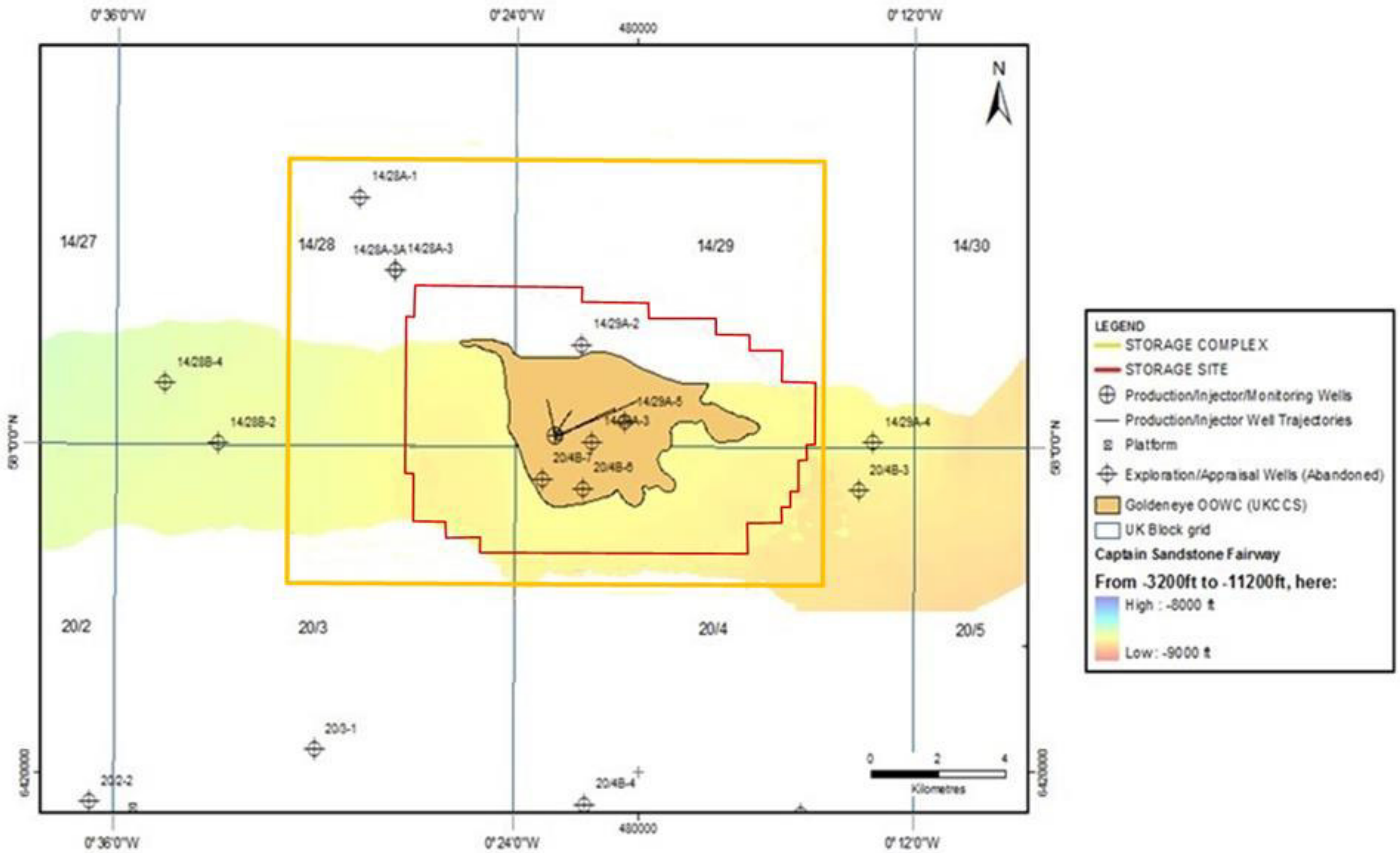


Figure 2-7: Geographical extent of the storage site and storage complex with extent of Captain Sandstone Member aquifer

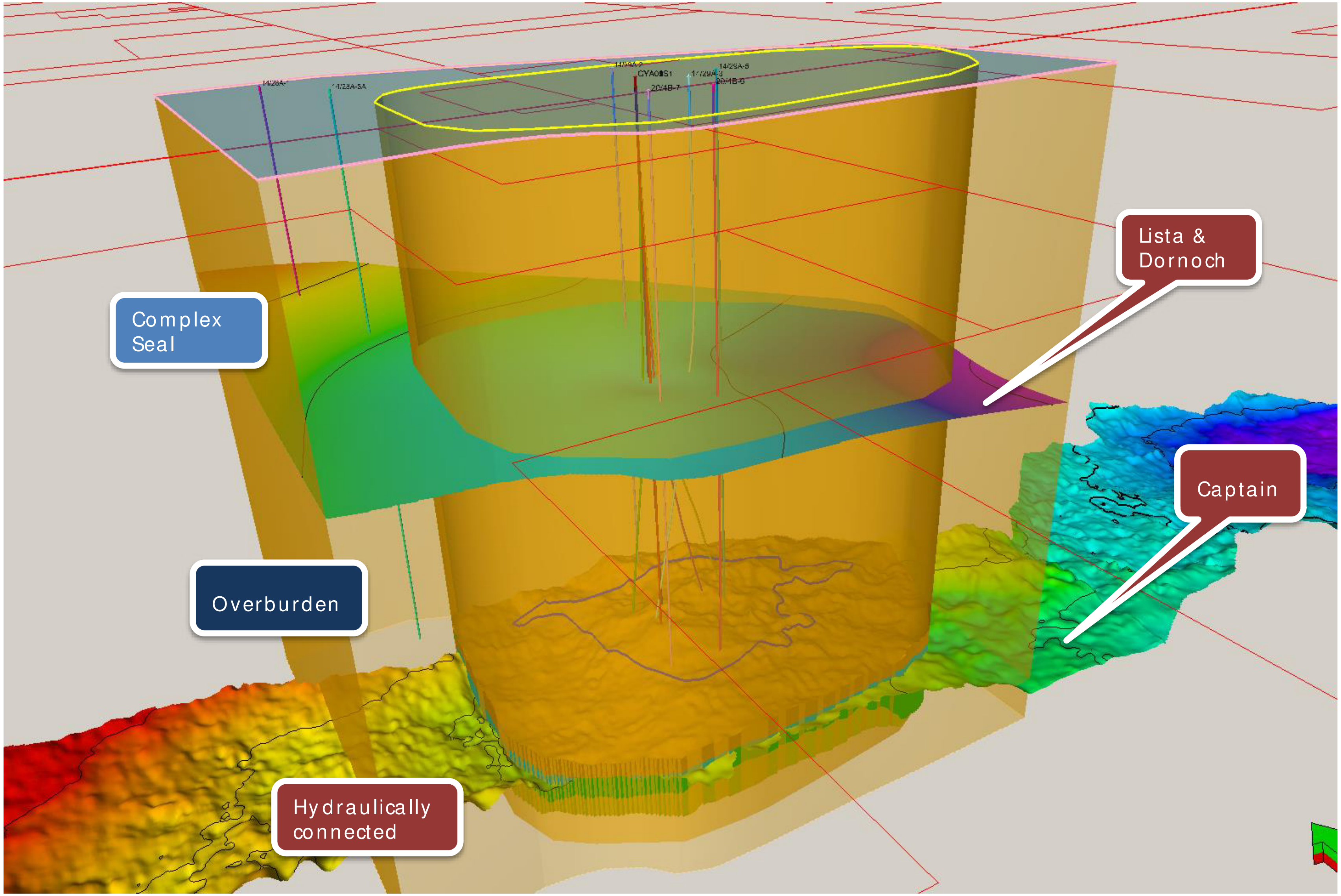


Figure 2-8: Schematic representation of the Goldeneye storage site and storage complex

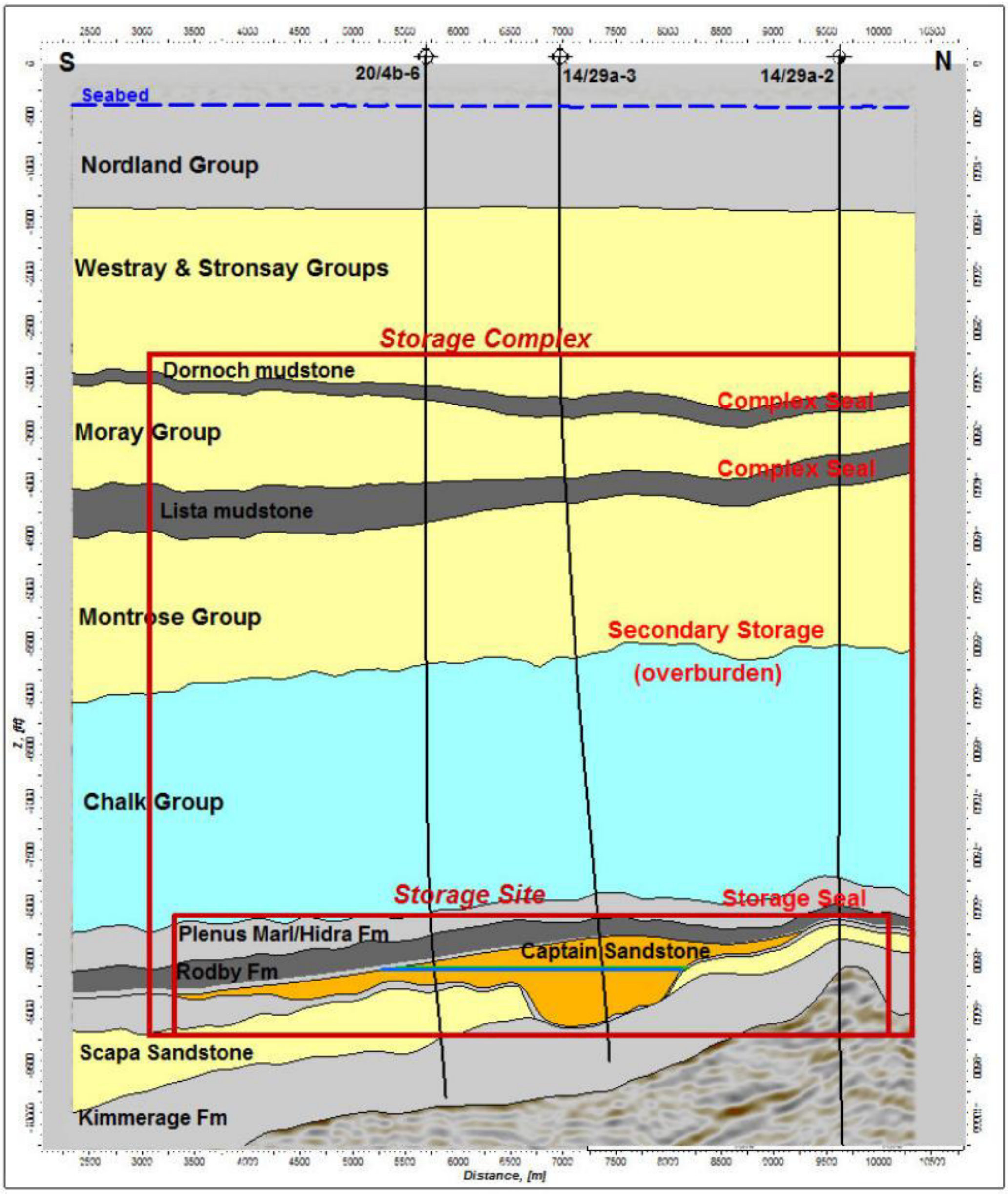


Figure 2-9: Vertical cross section of the storage site and storage complex.

2.8.3. Storage Leases and Licences

The licence block owners and operators in and around the vicinity of the development area have been identified and are detailed in Table 2-8.

Table 2-8: Licence block owners and operators.

Block	Equity holders
14/28b (E)	Centrica (25%), ExxonMobil (25%), Shell* (50%)
14/28c	Black Sapphire Resources Ltd. (100%)
14/29a	ExxonMobil (50%), Shell* (50%)
14/29e**	Encore Petroleum Ltd. (100%)
14/29c	Black Sapphire Resources Ltd. (100%)
14/29d	Encore Petroleum Ltd. (100%)
20/3b	ExxonMobil (50%), Shell* (50%)
20/4a	Apache North Sea Ltd. (50%) Nexen Petroleum U.K. Ltd.* (50%)
20/4b	Centrica (17.5%), Endeavour Energy Ltd.* (37.5%), Shell* (45%)
20/4c**	Encore Petroleum Ltd. (100%)
20/5f**	Encore Petroleum Ltd. (100%)

Note: * denotes Operator, ** potential Seaward Production Licence awards in the 26th Seaward Round.

This table was correct as of the end of October 2015. However, licence owners can change. For up-to-date information, please refer to the DECC website.

2.8.4. Reservoir Characteristics

The reservoir characteristics are summarised in Table 2-9 below:

Table 2-9: Reservoir Characteristics

Attribute	Value/Data
Type	Sandstone Captain formation
Formation temperature	Approximately 83°C @ 8400 ft. [2560 m] TVDSS Lower temperature to be encountered during injection
Formation Water	Present in the bottom of the well.
	Water will be initially at the sand face. Evidence of water from downhole pressure gauges in GYA03.
	Formation water around the wellbore will reduce significantly after 6 to 9 months of continuous CO_2 injection. However, water might return after long periods of no injection or insufficient cumulative volume.

Attribute	Value/Data
Average Reservoir (Captain D) Porosity and Permeability	~25% porosity 790 mD permeability The Captain D is a clean sandstone with very high Net to Gross Captain D presented an excellent connectivity during the hydrocarbon production phase.
Pressure Regime	(The pressure regime is given as an indication for general well/completion design selection. It will be re-calculated before any well operation and before working over the wells). An active aquifer supports the field. All the wells are currently shut in due to water breakthrough and isolated with deep and shallow downhole plugs.
	Original Reservoir Pressure ~ 3815 psia [263bara] @datum 8400 ft. [2560.32m] TVDSS Minimum Reservoir pressure after depletion ~ 2100 psia @ datum Current pressure is ~2650 psia (@ end of December 2013) @ datum
	Minimum expected reservoir pressure before CO_2 injection (approximately Year 2019)[1]: 2650 psia, Pressure Gradient Range - 0.319 psi/ft.
	Maximum expected reservoir pressure after 10 million tonne of CO_2 – (~Year 2031) 3450 psia, Pressure Gradient: 0.416 psi/ft. Information is of enough quality for this analysis/report on WFS. Different section of tubing (4 ½" and 3 ½") [114.3 mm and 88.9 mm] to be installed in each well will depend on this information.

Note 1: Current reservoir pressure is 2680 psia at end of November 2014. Maximum expected reservoir pressure after 15 years of injection is ~ 3800 psia.

2.8.5. Seismic Data Availability

Several seismic datasets were available that cover the South Halibut Trough, including 2D regional lines, the 1994 Greater Ettrick Regional 3D, the 1997 East Ettrick 3D, the 2001 Goldeneye PreSDM 3D and the 2001 Blake 3D – as shown in Figure 2-10. The Goldeneye Field itself was covered by several vintages of 3D seismic surveys as summarised in Figure 2-11.

Shell acquired the Greater Ettrick Regional 3D Survey, a low-fold quad-quad reconnaissance 3D survey in 1992, which was subsequently reprocessed in 1994. The Goldeneye discovery well 14/29a-3 was drilled on this dataset. Data quality is moderate to poor at target level. Following the discovery, a target oriented 230 km^2 high-fold seismic dataset the East Ettrick 3D Survey was acquired in 1997 which was centred on the Goldeneye Field and covered parts of Blocks 14/28b, 14/29a, 14/30a,b,c, 20/3b, 20/4b and 20/5c. This 3D survey was used for the Field Development Planning for the Goldeneye Field.

Despite extensive efforts during the (re-)processing of the 1997 3D seismic data, seismic data quality still remained only moderate around the target level due to the laterally variable shallow coal layers. In order to address these data quality issues a full 3D Pre-Stack Depth Migration (PreSDM) was carried out in 2001. This PreSDM dataset provided significant improvements in reflector continuity and resolution, and in fault plane definition. The PreSDM seismic cube was used to identify the development well locations prior to the start of development drilling in 2003.

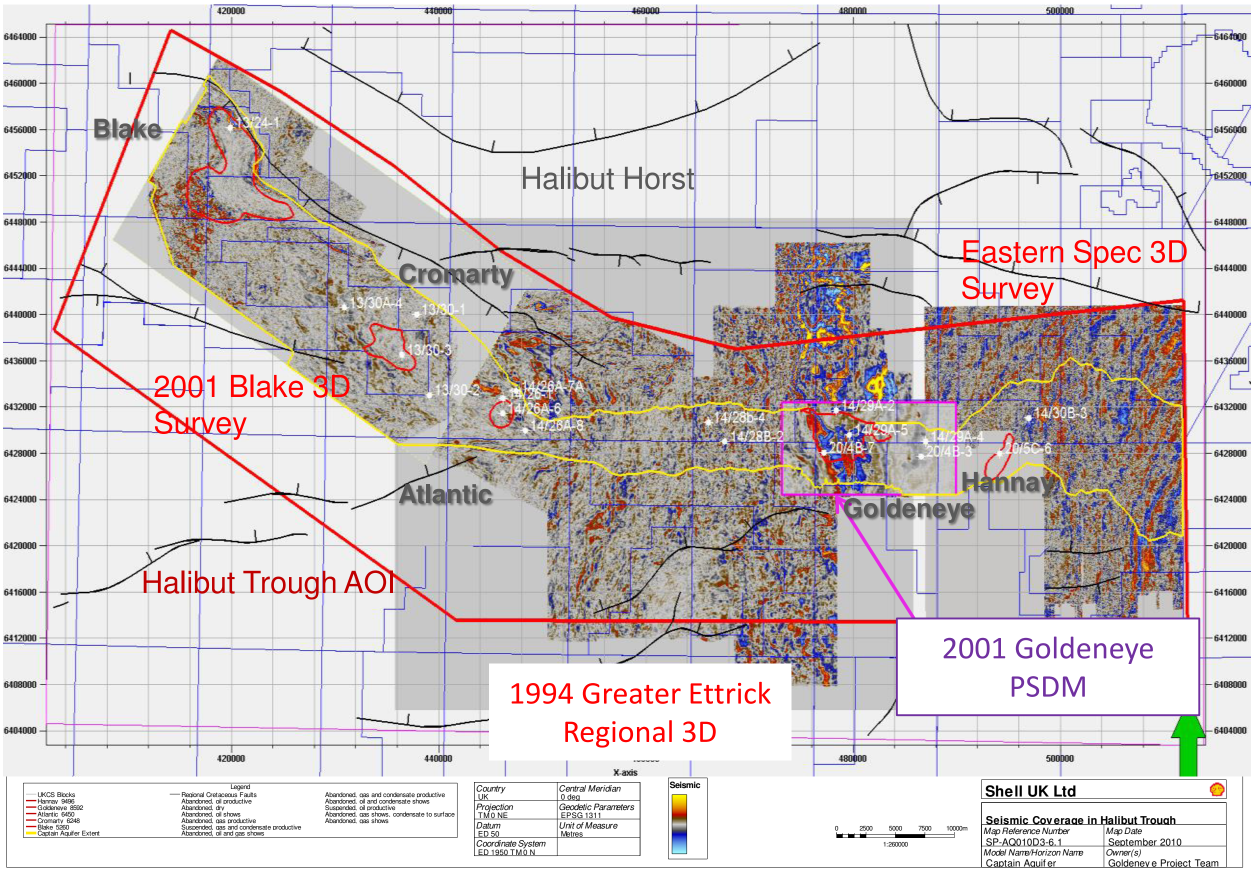


Figure 2-10: Regional seismic coverage in Halibut Trough

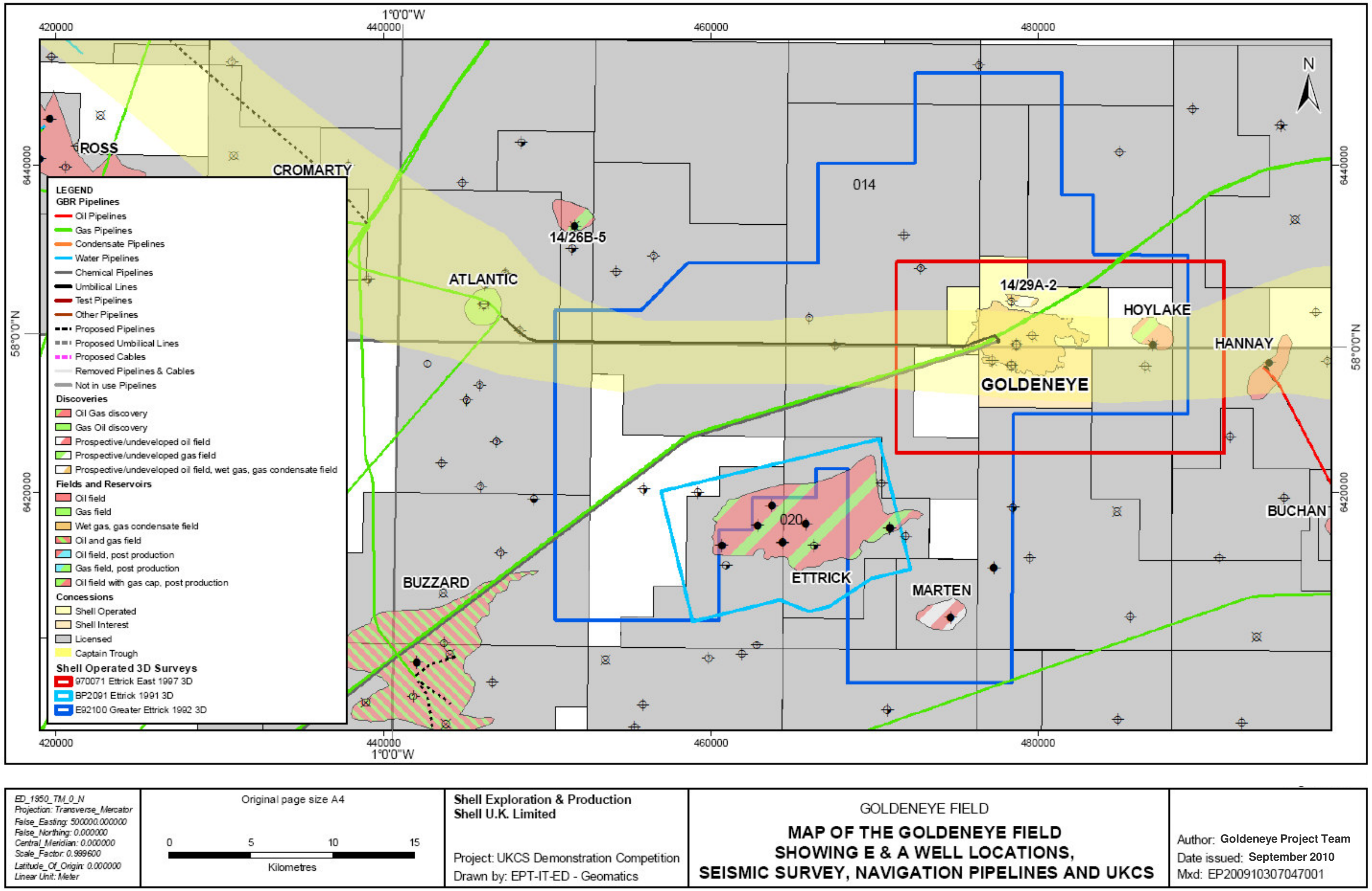


Figure 2-11: 3D seismic surveys available over the Goldeneye Field

Seismic interpretation of the Captain Sandstone is generally difficult due to problems in imaging the reservoir itself because of the poor impedance contrast at the top reservoir between the Captain Sandstones and the overlying Rødby shales. The seismic image quality at reservoir level is also reduced due to the effect of the overlying lithology. The overburden includes glacial channels, stacked, laterally varying, low-velocity coal layers and a thick high-velocity Chalk section. The glacial channels and coal layers are responsible for buried statics, and amplitude effects due to focussing of energy and absorption losses. The Chalk layer causes marked ray bending which is exacerbated by the high degree of rugosity exhibited by the Top Chalk. In addition, the seismic data are contaminated with water-bottom multiples and strong long-period multiples generated by the coal and chalk interfaces.

Figure 2-12 shows a regional seismic line running approximately west to east in the Outer Moray Firth. This regional line shows that data quality deteriorates below a single coal layer and that degradation is more severe below stacked coal layers. The number of coal layers above the Goldeneye Field varies from one to four. The regional line also shows an increase in the relief of the Top Chalk interface in the vicinity of the field. The Captain Sandstones dip about one to two degrees from west to east.

More information on the databases and studies used, as well as the geological framework for the storage site, storage complex and overburden can be found in APPENDIX A, B and C respectively of the Key Knowledge Deliverable 11.108 - Static Model Report [1].

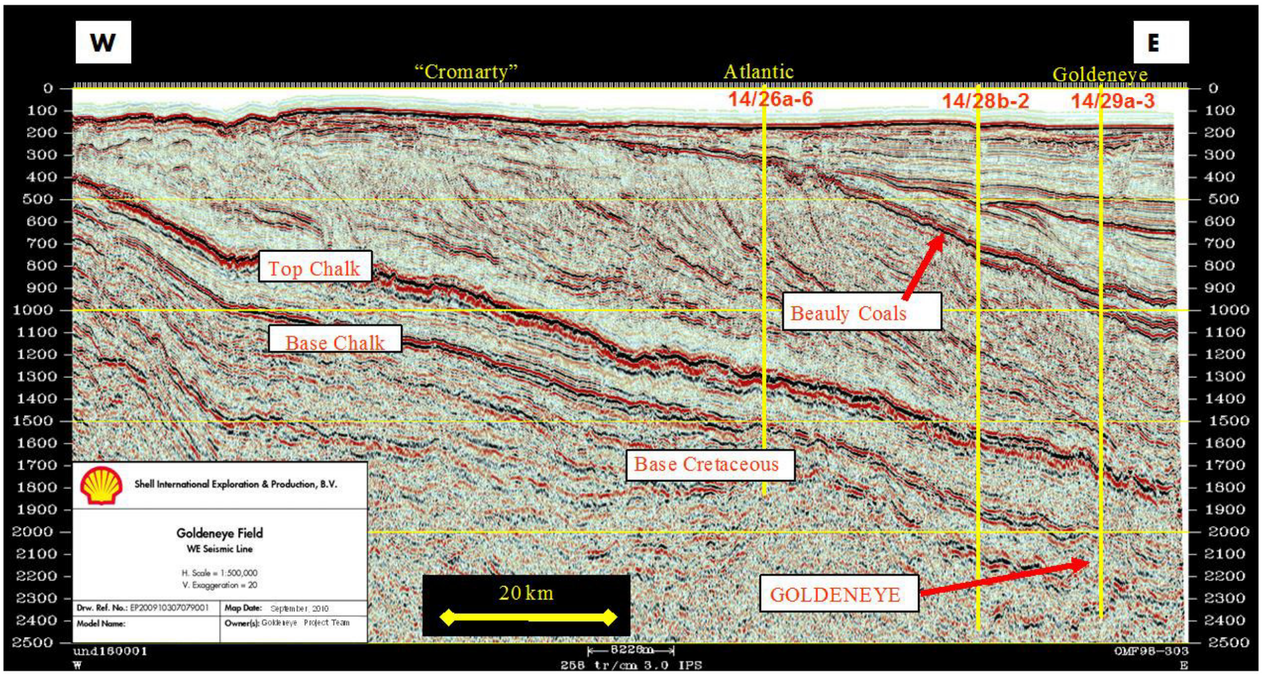


Figure 2-12: Regional W-E Seismic Line along Halibut Trough.

Note: Display is in TWT (Two-Way Time). The Goldeneye Field is located to the right of the display at around 2100 ms (2530 m).

2.8.6. Development wells

The five development wells drilled on the Goldeneye structure are listed in Table 2-10. The abbreviated well names are used in this document for ease of reference.

Table 2-10: Well name abbreviations.

Full well name	Abbreviated well name	Spudded (batch operations)
DTI 14/29a-A3	GYA01	8/12/2003
DTI 14/29a-A4Z	GYA02S1 (side track)	13/12/2003
DTI 14/29a-A4	GYA02	As above
DTI 14/29a-A5	GYA03	19/12/2003
DTI 14/29a-A1	GYA04	5/10/2003
DTI 14/29a-A2	GYA05	2/12/2003

2.8.7. Storage Capacity

At formal cessation of production, the ultimate volume of hydrocarbons recovered from the field was 568 Bscf gas and 23 MMbbl condensate since production started in 2004. This space voided from hydrocarbon production is equivalent to 47 million tonnes of CO_2. This represents a theoretical maximum volume of CO_2 that can be structurally trapped within the storage site. To arrive at a final estimate for the volume of CO_2 that it is possible to store, a number of other factors that either act to reduce or to increase storage capacity must be taken into account. These are discussed in detail in the Key Knowledge Deliverable 11.128 – Storage Development Plan [6] Section 6.5 and 6.6.

A significant volume of CO_2 will be capillary trapped in the aquifer rocks immediately below the original oil-water-contact, after the expansion and contraction of a 'Dietz Tongue': At Goldeneye pressures and temperatures, the CO_2 dense phase is less dense than water and so, under equilibrium conditions it will overlay the brine filled part of the reservoir. During injection, the CO_2 displaces water under segregated flow conditions and can tongue and override the water. It is estimated, taking discounted structurally trapped and the capillary trapped volumes of CO_2 into account, some 34Mt of CO_2 can be geologically stored in the Goldeneye storage site.

An uncertainty analysis was carried out, oriented towards the impact of CO_2 injection, aiming to deliver a set of parameter ranges and subsurface realisations that need to be modelled (covering both static and dynamic modelling). The study showed that three major static elements could impact the storage capacity of Goldeneye:

(a) Extension of the stratigraphic pinch-out;

(b) Structural dip on the western flank of the field; and

(c) Internal Captain Sand stratigraphy (thickness).

In addition, dynamic elements were also considered within the uncertainties that will potentially have an impact on the CO_2 storage capacity of the field, mainly related to the displacement mechanism and the unfavourable mobility ratio of the process. These elements are:

(a) Relative permeability end points (both water and gas/CO_2), and

(b) Residual gas saturation (S_{gr}).

The entire suite of static reservoir model realisations have been simulated and a range of injection scenarios have been tested. Much of the simulation work referred to here was performed during the early stages of preparation of this report, and was done for a scenario requiring storage of 20 Mt of CO_2 with an injection rate of 1 Mt p.a. Results from such cases are valid to support storage of 15 Mt, and are identified where appropriate. With regard to the uncertainties evaluated, all the scenarios have sufficient capacity to hold up to 20 million tonnes of CO_2.

In order to determine the maximum geologic carbon storage capacity for the Goldeneye reservoir, a theoretical scenario of 50 years continuous CO_2 injection at 1 Mt per annum revealed that over 30 Mt of CO_2 had to be injected to reach a structural spill point and create an egression, i.e. there is a substantial storage buffer within the hydrocarbon bearing structure before sequestration expands into aquifer storage.

Further information on the storage capacity, the studies and the methodology used for its assessment can be found in the Key Knowledge Deliverable 11.128 – Storage Development Plan [6]. Information on the dynamic modelling conducted for the storage site is located in the Key Knowledge Deliverable 11.122 – Dynamic Reservoir Modelling Report [2].

2.8.8. Injectivity Assessment

The initial CO_2 injectivity in Goldeneye is expected to be in line with the reservoir's hydrocarbon production properties. The injection pressure above the reservoir pressure for the expected injection rates is in the order of 14 to 28 bara. This conclusion is based on the rock properties and the hydrocarbon productivity. Corrections are made to the hydrocarbon productivity to obtain the expected CO_2 injectivity.

Further discussion of the anticipated injectivity rates throughout the lifetime of the Project, the possible causes of reduction in injectivity rates and the mitigations are presented in Key Knowledge Deliverable 11.128 – Storage Development Plan [6].

2.8.9. Storage Operations

The CO_2 injection conditions are summarised in Table 2-11 and Table 2-12 below:

Table 2-11: CO_2 injection rates

Attribute	Description
Total CO_2 available	Design Rate (capacity of the capture plant): 138.3 tonnes/h equivalent to 63 MMscfd Normal Operating Conditions ~ 130 tonnes/h (59 MMscfd) Turndown Rate of surface facilities ~ 89.9 tonnes/h (65% of the design case, 41 MMscfd) It is estimated that the injection will take place over a period of 15 years for up to 15 million tonnes (including downtime).
CO_2 fluctuation	For the injection years, the turndown case will be 65%. All the surface equipment should be design to minimum turndown of 65%. The reference case is to operate the capture plant at based load (i.e. continuous flow) during the first five years on injection.

Table 2-12: CO_2 arrival temperature at the platform

Attribute	Design Minimum (Winter)	Operational (Winter)	Operational (Summer)	Design Maximum (Summer)
Goldeneye Site Air temperature, °C	-8.2	7	12	24.5
Goldeneye Site Sea surface temperature, °C	1.0	7	14	21.0
Goldeneye Sea bed temperature, °C	4.0	7	9	11.0
Arrival CO_2 temperature to the platform °C (120 bara)	2.3	5.3	8	10.1
Isenthalpic expansion to 115 bara, °C	2.2	5.2	7.9	10
Isenthalpic expansion to 50 bara, °C	0.5	3.1	5.5	7.2

The current operating philosophy is to inject CO_2 in single phase by maintaining wellhead pressures above the saturation line to avoid extremely low temperatures in the well caused by the Joule Thomson effect.

From the table above the maximum expected CO_2 arrival temperature is 10.1°C. The saturation pressure at this temperature is 45.13 bara; using a margin of 50 psia (3.5 bara) between the minimum wellhead injection pressure and the saturation pressure a minimum injection pressure of 50 bara is derived. This minimum wellhead pressure (50 bara) was used during FEED as a conservative threshold considering the maximum manifold temperature this can be reduced for colder CO_2 arrival temperatures.

The bottom hole temperature (BHT) will depend on the injected fluid temperature and the rate of injection, the expected BHT is between 23°C to 35 °C. These steady state injection characteristics are summarised in Table 2-13 below.

Table 2-13: Steady state injection characteristics

Attribute	Description
Wellhead pressure (WHP)	Minimum: 50 bara It can be optimised during cold months considering the arrival temperature of the CO_2 to the platform. CO_2 will be injected in a single phase with wellhead pressures kept above the saturation line. Maximum: 120 bara This is the maximum arrival pressure to the platform limited by the offshore pipeline
Manifold CO_2 temperature (MFT)	CO_2 arrival temperature will present some minor seasonal variations. This will be similar to the seabed temperature with some variations due to CO_2 riser expansion For design purposes – the minimum temperature is estimated at 2.3°C, the maximum is 10.1°C

Attribute	Description
	For operational purposes the expected fluctuation is between 5.3°C to 8°C
Wellhead CO_2 temperature (FWHT)	There will be some JT effect across the choke being more pronounced at lower wellhead injection pressure The minimum temperature is 0.5°C at 50 bara injection pressure The maximum temperature is 10.1°C at 120 bara injection pressure
Bottom Hole temperature (BHT)	The Bottom Hole Temperature (BHT) will depend on the injected fluid temperature and the rate of injection. There will be reduction of temperature around the injectors due to cold CO_2 injection. For the CCP rates in the Peterhead project, the expected BHT is between 23°C to 35 °C.

2.8.9.1. Transient conditions (starting-up, closing-in operations)

During transient operations (closing-in and starting-up operations), a temperature drop is observed at the top of the well for a short period of time. The faster the shut-in or faster the well opening operation, the lower the resultant temperature drop. The cooling effect diminishes deeper into the well due to limited CO_2 flashing and heat transfer from surrounding wellbore.

The reservoir pressure affects the temperature calculation during the transient calculations. The lower the reservoir pressure, the lower the surface temperature expected during transient operations and hence the higher the stresses/impact in terms of well design.

In summary, the expected transient conditions are shown in Table 2-14 as follows:

Table 2-14: Results of transient calculations – design case (base oil in annulus)

	Design Case	Operating case
Steady State CO_2 MFT, °C	3	-
Steady State MFP, bara	120.2	-
Reservoir Pressure, psia	2500	2500
Steady State Conditions		
FWHP, bara	45	115
FWHT, °C	1	4
BHT, °C	17	20
Transient conditions		
Close in operation, h	2	0.5
Start Up operation, h	2	1
Coldest temperature (wellhead)		
Fluid CO_2, °C	-20	-17
Average tubing, °C	-15	-10
A annulus, °C	-11	-4
Production casing, °C	-10	-1

Strict operational procedures need to be implemented and adopted during CO_2 operations to avoid extreme cooling of the well components due to temperature limitation of the well components. These are detailed in the Key Knowledge Deliverable 11.128 – Storage Development Plan [6].

Frequent opening-up and closing-in events should be avoided to limit the stresses in the well (as a result of temperature reduction over short periods of time) and to reduce the operation intensity in the wells.

2.8.9.2. Closed-in Tubing Head Pressure

The Closed-In Tubing Head Pressure (CITHP) will depend on the reservoir pressure (or downhole pressure) and the fluid inside the tubing. Two extreme cases can occur and have been considered:

1. Well filled with CO_2; and
2. Well filled with CH_4 (methane).

The wells will be designed to accommodate water, CO_2 and/or gas for corrosion purposes and wellhead pressures related to hydrocarbon gas filling the tubing.

For a CO_2 filled well at the end of the 15 million tonnes injection period, the CITHP is relatively low (approximately 50 bara) at the maximum predicted reservoir pressure of around 260 bar as shown in Figure 2-13.

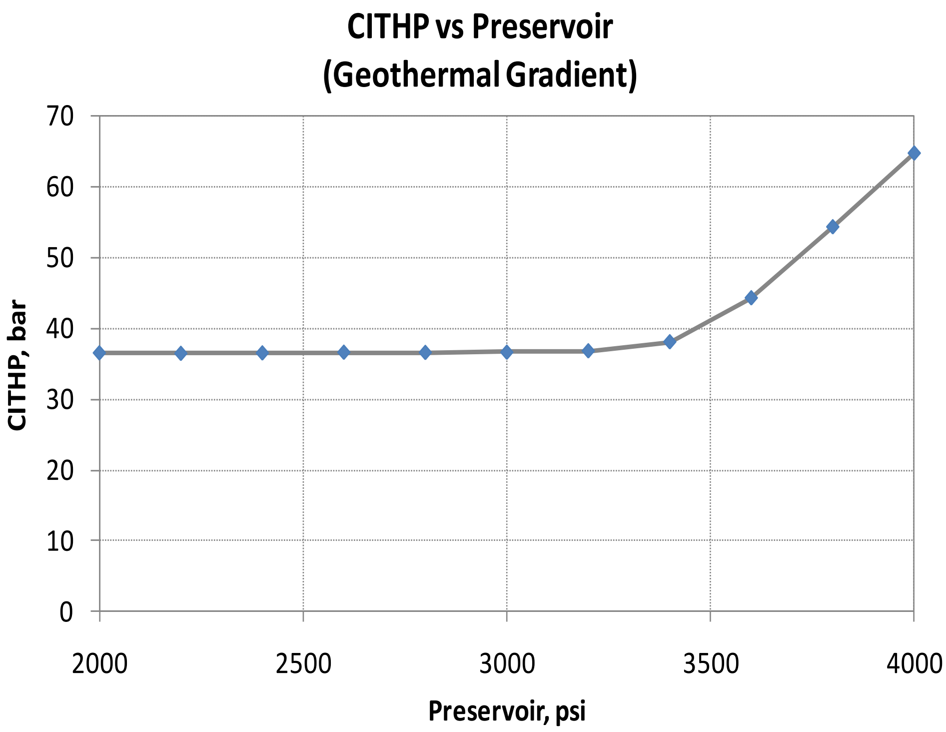


Figure 2-13: CITHP for a well filled with CO_2

Note: $P_{reservoir}$ is reservoir pressure.

In the scenario where the well is full of hydrocarbon gas then the predicted CITHP at the same reservoir pressure (260 bar) would be in the order of 220 bara (assuming methane filled the tubing), as shown in Figure 2-14.

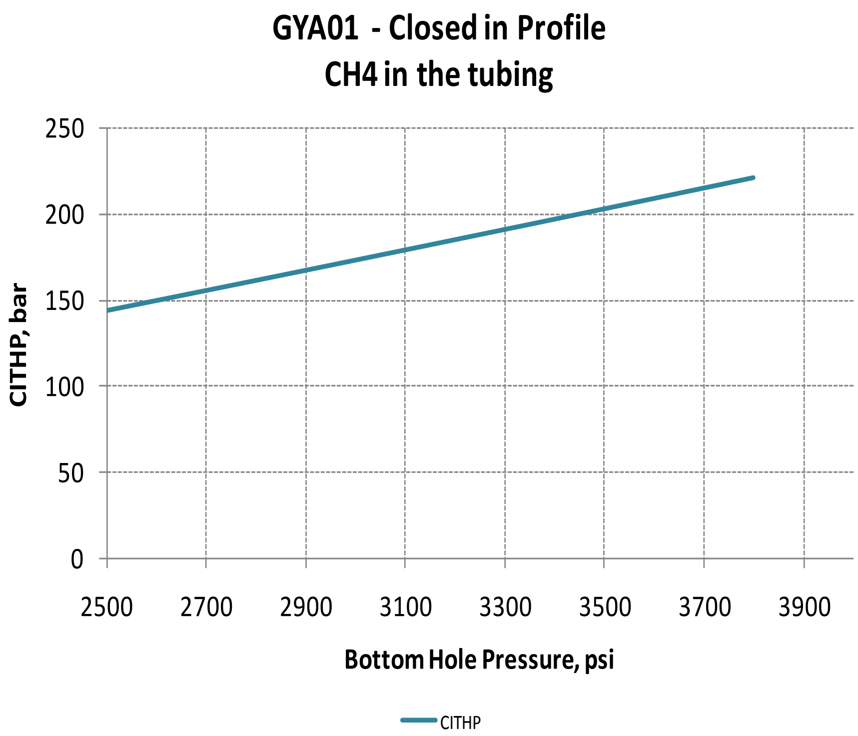


Figure 2-14: CITHP for a well with Methane in the tubing

2.8.10. Storage Integrity

The Goldeneye store has a competent and extensive caprock that has contained gas for around fifty million years. Above the caprock there are approximately 750 m of low permeability chalk formations followed by a succession of approximately 700 m of sandstones and mudstones beneath the secondary and tertiary seals to the complex – the Lista and Dornoch mudstones. These formations are overlain by more interbedded sands and silts that will provide a baffle to CO_2 movement.

The field has very few well penetrations (five production wells and four exploration and appraisal wells) and the status of these and of the penetrations in neighbouring areas is known. All penetrations in the storage complex that penetrate the Captain sandstone have competent cement plug abandonments at this level.

There is limited evidence of faulting in the overburden, and no faults have been identified that penetrate both the storage and complex seals. None of the faults in the storage complex is critically stressed. Data on the position and intensity of earthquakes in the North Sea shows the area in the vicinity of Goldeneye to be seismically low-active.

Geomechanical assessment of the caprock has shown that re-pressurisation does not fracture the rock, while geochemical modelling has shown that the acidic fluids created by the CO_2 injection do not perforate the caprock or cemented fractures. A coupled geochemical/geomechanical experiment on the reservoir rock has shown that the strength does not decrease upon interaction with these acidic fluids even when the calcite cement is dissolved.

Assessment of monitoring feasibility shows that migration of CO_2 outside the store can be detected using time-lapse seismic techniques.

Further information on the storage facility and the integrity assessment can be found in the Key Knowledge Deliverable 11.128 – Storage Development Plan, Section 9 [6], Key Knowledge Deliverable 11.113 – Well Integrity Assessment Report [5] and BGS report [18]. Supplementary information on the geomechanics and geochemistry of the storage site can be found in Key

Knowledge Deliverable 11.115 – Geomechanics Report [3] and Key Knowledge Deliverable 11.116 – Geochemical Reactivity Report [4].

2.8.11. Monitoring Plan

The monitoring plan is intended to be 'trigger-based', with triggers related to leakage scenarios built from identified leakage threats. To address these, a two-part monitoring programme has been devised:

- Base case plan: monitors the conformance of CO_2 injection against the modelled prediction and identifies unexpected CO_2 migration within the storage complex. This allows action to be taken (if required) to ensure the integrity of storage before leakage would occur.
- Contingency plan: in the unlikely event of leakage, the contingency plan is mobilised to locate the source of the leak and enable corrective measures to be implemented.

The monitoring plan encompasses all phases of the project and is illustrated schematically in Figure 2-15:

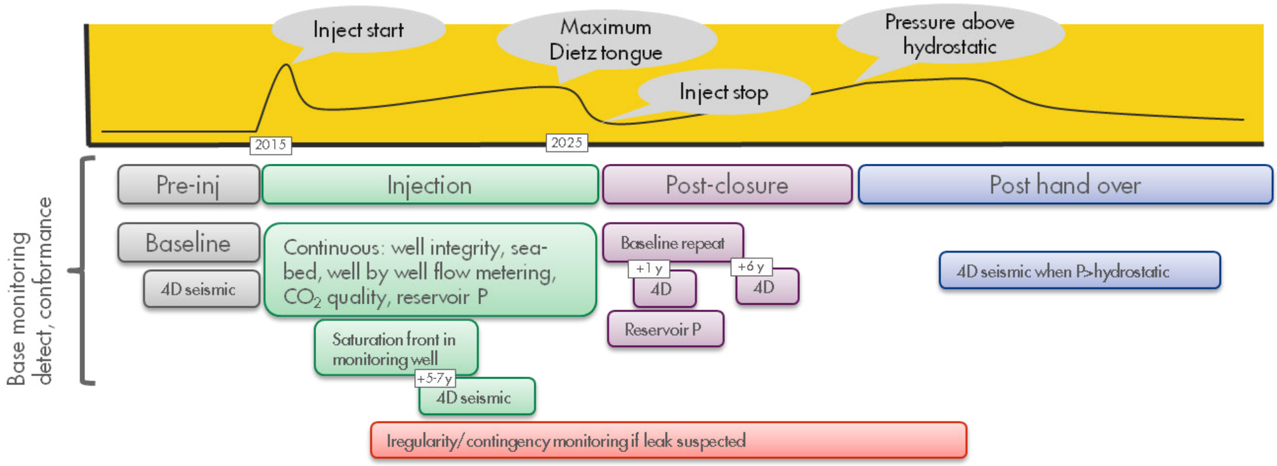


Figure 2-15: Schematic of the monitoring plan. The vertical axis on the schematic represents risk of significant irregularity.

Full details are provided in Section 10 of the Key Knowledge Deliverable 11.128 – Storage Development plan [6].

In order to develop effective base case and contingency plans, it is important to identify the likeliest leakage event scenarios. These are based on the residual risk after natural and engineered barriers have been taken into account. The leakage scenarios are grouped by categorising threats/risks identified in the containment risk assessment. It must also be taken into account that individual risks may act in combination to turn a containable threat of migration into a leak. The scenarios are used to generate requirements for data acquisition and technology selection. The leakage scenarios are presented in Table 2-15 and discussed in further detail in the Key Knowledge Deliverable 11.128 – Storage Development Plan [6].

Table 2-15: Grouping of threats into leakage scenarios

Leakage scenarios	Leakage mechanism	Threats (detailed)
Leakage through plugged and abandoned (P&A) wells	Existing P&A wells	Flow through P&A exploration wellbore.
	Post-injection P&A wells	Flow through P&A injection wellbore to near surface.
	Caprock integrity failure	Acid fluids react with wellbore plugs, cement and casing.
Leakage through injection wells	Development wells	Cross flow behind production casing.
		Injection well tubing leak.
	Caprock integrity failure	Acid fluids react with wellbore plugs, cement and casing.
Leakage through (open or reactivated) fault/fracture	Open faults/fractures	Flow along existing fault/fracture crossing primary and/or secondary seal.
	Caprock integrity failure	Acid fluids react with minerals in fault/fracture allowing fault to reactivate
		Acid fluids react with minerals in fault/fracture opening it.
	Reactivated fault/fracture	Injection pressure causes formation of new open fault in caprock.
		Injection pressure causes shear fracture.
		Injection pressure causes opening/formation of fractures in caprock.
	Caprock integrity failure	Acid fluids react with reservoir matrix, weakening it and causing failure.
Lateral migration in reservoir	Migration past spill point	Lateral migration past the spill point and into the Captain fairway.
Migration in overburden	Wells, fault/fracture, lateral migration	Combination of well or fracture leakage with lateral migration along permeable unit in overburden

In the event of a leak being confirmed, mitigation will be addressed by the Corrective Measures Plan, which is summarised below.

2.8.12. Corrective Measures Plan

The corrective measures plan is described in greater detail in the Key Knowledge Deliverable 11.128 – Storage Development Plan [6].

The key factors in the development of the plan are the boundary conditions and definitions as described in the EU directive for the safe storage of carbon dioxide. The boundary conditions and definitions are summarised below:

(i) Corrective measures are actions, measures or activities taken to correct significant irregularities or to close leakages in order to prevent or stop the release of CO_2 from the storage complex.

(ii) Significant irregularity means any irregularity in the injection or storage operations or in the condition of the storage complex itself, which implies the risk of a leakage or risk to the environment or human health;

(iii) Leakage means any release of CO_2 from the storage complex;

(iv) Storage complex means the storage site and surrounding geological domain which can have an effect on overall storage integrity and security; that is, secondary containment formations;

The corrective measures plan acts to (in order of priority):

1. Prevent risks to human health.
2. Prevent risks to the environment.
3. Prevent leakage from the storage complex.

The plan is site specific and risk based and covers the entire storage complex.

3. End-to-End CCS Chain Operating Philosophy

3.1. Overview

Once operational, the PCCS Project will be operated and controlled from the dedicated PCCS Control Room which will be located within the PCCS boundary on the Peterhead Power Station site. This is with the exception of GT13, ST20 and the associated Block 2 equipment of the power plant which will be controlled from the Peterhead Power Station control room. The PCCS control room will be remotely located from the existing Peterhead Power Station control room. The Goldeneye Platform will remain a Normally Unmanned Installation and will be operated from the PCCS Control Room under normal operating conditions, although the ability to perform local control operations on the platform will be retained. When required, methanol injection will be managed from the PCCS Control Room. However, methanol operations will be carried out by the existing Shell St Fergus Terminal control room under instruction from the PCCS Control Room. The Shell St Fergus Terminal control room operations will not be part of the PCCS project. This support will be provided under a third party agreement to the PCCS Project.

3.2. End-to-End Process Control

The required capacity of the system is determined by the source of CO_2, namely the GT13 gas turbine. About 90 % of the CO_2 from the flue gas is captured in the absorber column. The lean flue gas is released to atmosphere via the existing 170 m tall stack.

CO_2 is subsequently recovered from the solvent in the CO_2 stripper at a pressure of approximately 1 barg. The CO_2 is then compressed to pipeline pressure onshore. Normally the pipeline entry pressure is approx. 120 barg, but can be dropped to 90 barg at Goldeneye topsides in case of temporary shortfall. There are no significant temperature effects that influence the operating envelope since the CO_2 quickly cools to seabed temperature in the pipeline irrespective of operating pressure and remains stable thereafter unless a subsequent pressure drop causes Joule-Thompson cooling.

The compressed CO_2 is subsequently transferred to the offshore platform some 100 km away where it is injected into one or a number of injection wells. These injection wells have a range of designs that allow CO_2 to be continuously injected in dense phase over a range of CO_2 rates.

The Goldeneye reservoir is below hydrostatic pressure due to depletion of hydrocarbons. Over time, this pressure is expected to relax slowly back to hydrostatic pressure with a top hole pressure close to 0 barg. However, injection of dense phase CO_2 at this pressure will cause significant refrigeration of the well bore and is therefore not practical. In order to avoid this, the Goldeneye wells' production tubing will be changed to smaller bore 'velocity' tubing. The injection tubing is sized to produce sufficient pressure drop to maintain the injected CO_2 in dense phase. This imposes a minimum flow rate constraint on the well and a corresponding minimum tubing head injection pressure at the wellhead. When there is insufficient CO_2 to maintain this injection rate, the well must be shut-in. Well shut-in causes a collapse of CO_2 pressure that refrigerates the wellbore. The control scheme should act to minimise the low temperature cycling of the wells. This is achieved by efficient use of line-pack. Pipeline pressure should normally be controlled to maximise line pack with the injection rate and injection tubing head pressure above the minimum requirement. During temporary outage of Peterhead CO_2 export, the injection rate must be reduced to a minimum to allow injection to be sustained for as long as possible. The pipeline topsides pressure is prevented from dropping below 90 barg. This is required to prevent the pipeline entering the two-phase regime during a shutdown.

The Peterhead Carbon Capture Project (PCCS) requires a measured amount of methanol to be injected into the wells prior to the injection of carbon dioxide.

It is intended to use the existing glycol supply system at St Fergus to supply methanol to the platform using the existing 4" (101.6mm) piggy-back pipeline.

3.2.1. Overall Capacity Control

The maximum delivery of CO_2 to the offshore transportation system, assuming the target 90 % capture rate, is 138.3 t/h. The GT13 unit is assumed to normally be operated at base load (and close to rated output). Later in the project, once the storage reservoir has established the required back pressure to allow the wells to operate at lower injection rates whilst remaining in the dense phase region, GT13 may be run at reduced output, ranging down to approximately 86 t/h of CO_2 produced from the CCP to demonstrate the level of flexibility in the End-to-End CCS chain system.

If GT13 shuts down, the CO_2 capture will stop as well since the supply of CO_2 to the CCP will cease. Line-pack in the offshore transportation system is used to maintain well injection for as long as possible during onshore outages.

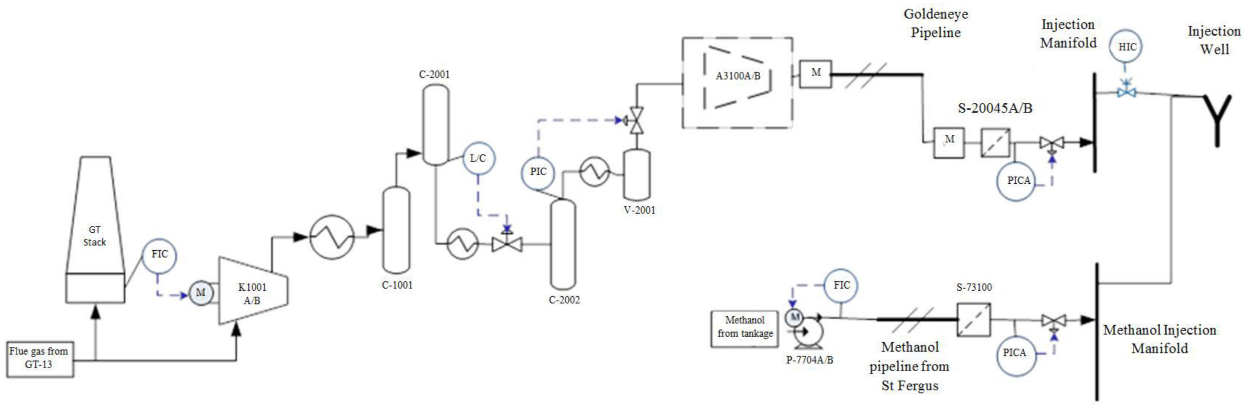


Figure 3-1: End-to-end throughput control

The GT13 flue gas flow rate is determined by the GT's MW setting selected by the power station operator. A small positive flow of flue gas to atmosphere will be maintained through the 90 m repowering stack with a booster fan used to draw the majority of the GT flue gas into the Carbon Capture Plant. Therefore the gas flow through the Gas Pre-Treatment unit into the CCP will automatically be adjusted to follow the GT flue gas output.

The flue gas flow into the CCP determines the circulation rate of amine required in the CCP to process the CO_2 in the flue gas. The rich amine flow will be set by liquid level control in the CO_2 Absorber (C-2001). Pressure control in the CO_2 Stripper (C-2002) sets the rate at which the CO_2 gas then flows to the Compression and Conditioning plant. There is no significant CO_2 storage in the onshore CCCC Plant and therefore the rate of export of CO_2 into the Goldeneye pipeline is set by the inlet flue gas rate to the CCP.

To maintain linepack in the offshore pipeline, the arrival pressure at the topsides will be maintained via pressure control on the topsides choke valve.

When operating with a single injection well, the well choke will be set at 100 % (fully open). Ultimately, when more than one injection well is operated, the individual chokes at the wellhead will allow for control of the relative injection rates.

The wells' injection quantity can be varied between maximum and minimum of each of the wells. For the design well, the minimum and maximum injectivity rates correspond more or less with the maximum and minimum CO_2 production rates, i.e. 86 to 138 t/h. However, the well's injectivity will vary with time. As time progresses, the injectivity range is expected to increase due to the increasing backpressure of the reservoir.

Injection will be controlled in two modes:

1. Mode A is the normal mode when CO_2 export rate from Peterhead is greater than the minimum injection rate; and
2. Mode B is the line unpack mode when the CO_2 export rate from Peterhead is below the minimum injection rate.

In case the CO_2 availability increases above the injectivity of the current well, the pressure in the pipeline will increase, leading to a requirement to stop CCS operations. This is an undesirable event, so the alternative would be to find a way to reduce the amount of CO_2 becoming available. This could be done by e.g.:

- Reduce the flue gas intake, i.e. not taking all the flue gas from the main gas turbine;
- Reduce CO_2 capture by reducing the solvent circulation rate; and

- Reduce CO_2 delivery to the pipeline by delivering part of the produced CO_2 back to the absorber column.

These measures will give the operator the required time to decide on taking a different well into operation with a different capacity. These operations scenarios will be developed further in the Detailed Design phase.

After an operational event when the pipeline pressure has been reduced due to pipeline unloading, and the CCCP has shut down, the pipeline pressure will be below the permissible discharge pressure for the CO_2 compressor. To enable restart of the compressor, backpressure control valves are located at the compressor discharge and will allow the compressor and the CO_2 conditioning equipment to run at its normal pressure while raising the pipeline inlet pressure and re-establishing normal operating levels.

3.3. End-to-End Process Streams

Throughout FEED three design cases were considered for the development of the specifications of the full CCS chain. The cases were:

1. Design Load Max;
2. Normal operation; and
3. Turndown.

The 'Design Load Max' case corresponds to the maximum possible output from the power plant and CCCC plant during the most favourable ambient conditions.

The 'Normal operation' case corresponds to the output from the power plant and CCCC plant when operating at the reference ambient conditions at the Peterhead Site.

'Turndown' case represents the lower limit of operation of the chain, in terms of stable CO_2 throughput, and is used to define the minimum injection flow rate required from the wells. This is approximately equivalent to GT13 operating at 65 % output and the CO_2 export at 70 % of the normal operation case. Further information on the process conditions for each stage of the process stream (including gas compositions/emissions and GT efficiencies) and a detailed diagram of the project interfaces can be found in Sections 2.6, 4, 5 and 6 of the Key Knowledge Deliverable 11.003 – Basis of Design Engineering Package [8].

The PCCS project main process streams are schematically shown in below in Table 3-2.

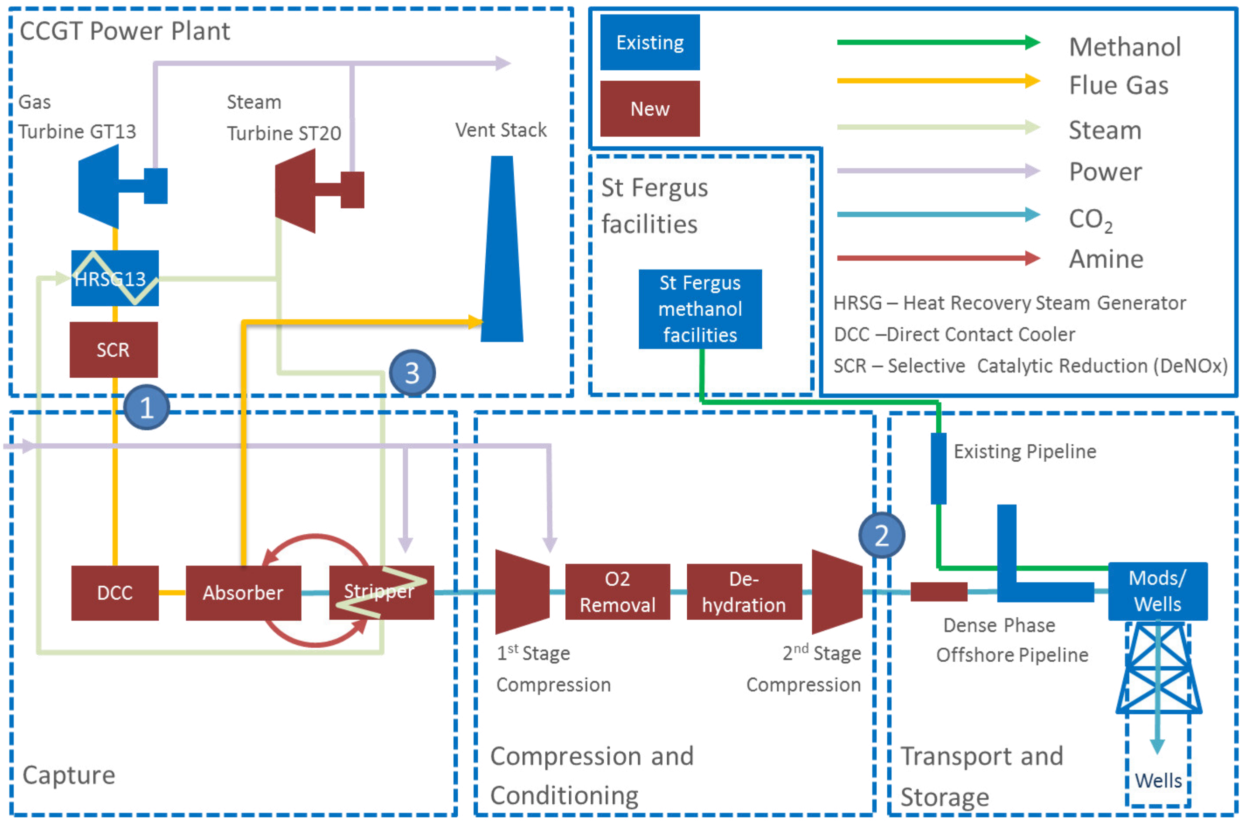


Figure 3-2: CCS Chain Schematic

Table 3-1 details the key parameters at the flue gas inlet to the capture plant booster fan, denoted as Stream 1 on Figure 3-2.

Table 3-1: Flue Gas Parameters

Battery Limit Conditions Gas Inlet to Capture Plant Booster Fan	Units	Value Normal Operation Case	Value Turn down	Value Design Load Max
Gas Inlet Flowrate	kg/s	685	512	710
CO_2 Mass Flowrate	t/h	145.5	99.9	153.1
Operating Temperature	°C	100	100	100
Operating Pressure	bara	1.013	1.013	1.040

Table 3-2 details the key parameters at the CO_2 export from the gas compressor to the subsea pipeline, denoted as Stream 2 on Figure 3-2.

Table 3-2: CO_2 from Compressor Parameters

Battery Limit Conditions CO_2 from Compressor	Units	Value Normal Operation Case	Value Turn down	Value Design Load Max
CO_2 Mass Flowrate	t/h	130.3	89.3	138.3
Operating Temperature	°C	125	25	25
Operating Pressure	bara	121	121	121

Table 3-3 details the key parameters at the interface of the low pressure steam feed to the capture plant, denoted as Stream 3 on Figure 3-2.

Table 3-3: Low Pressure Steam to Capture Plant

Battery Limit Conditions LP Pressure Steam	Units	Value Normal Operation Case	Value Turn down	Value Design Load Max
Mass Flow	t/h	173	116	220
Operating Temperature	°C	142	139	141
Operating Pressure	bara	3.4	3.1	3.2

3.4. End-to-End CO_2 Venting Philosophy

There are two principle means for CO_2 to be released to atmosphere in the PCCS CO_2 system design:

- Via vent stacks; and
- Via Pressure Safety Valves (PSVs) and thermal relief.

Where the potential to be able to release large volumes of CO_2 is required, this is achieved onshore via vent stacks with the CO_2 first heated (via a KO drum or in the Onshore Gas-Gas Heat-Exchanger) to aid buoyancy and dispersion. Direct venting is proposed offshore via a new dedicated CO_2 vent.

For the onshore CO_2 system, PSVs release CO_2 into vent headers with CO_2 ultimately released to atmosphere via either the existing 170 m tall stack or the new vent stack local to the compression plant.

Therefore the primary PCCS CO_2 vent locations are:

- Onshore (Peterhead Power Station) – venting to the bottom of the absorber tower, where it is recycled in the absorption process. Some of this vented CO_2 may eventually be released to atmosphere via the existing 170 m tall stack;
- Onshore (Peterhead Power Station) - at the vent stack local to the compression plant;

- Offshore (Goldeneye platform) – at the existing vent stack structure, which will be retained and modified to be suitable for the required CO_2 duty; and
- Offshore (Goldeneye platform) – via below deck thermal relief valves.

The results of CO_2 dispersion modelling studies performed during FEED confirm that little or no slumping back to the ground is predicted to occur provided that there is some air movement. On completely still days then there is the potential that the HSE's eight hour CO_2 exposure limit could be reach if mitigating action were not taken. Operational restrictions are therefore proposed to prevent venting of CO_2 on completely still days when the vented CO_2 could potentially slump to ground.

Since onshore CO_2 venting takes place via the existing 170 m tall stack or the new compression plant vent stack, the risk to persons (on or off site) is considered to be minimal and can be controlled under normal site operations. Additional mitigation measures include installation of CO_2 detection at the Peterhead Power Station site and use of personal CO_2 detectors for site staff once the carbon capture plant is operational. These measures will be reviewed further and finalised during Detailed Design.

Although GT13 is intended to be operated in abated mode with the flue gas CO_2 capture and stored, GT13 will continue to be able to operate in unabated mode should this be required e.g. in the event the capture plant is unavailable. In unabated mode, the GT13 flue gas will be emitted to atmosphere via the existing 90 m repowering stack as per present power station operations.

3.5. End-to-End Metering and Monitoring Philosophy

The metering proposed for the PCCS project is required to satisfy the following:

- Custody Transfer requirements (e.g. import / export electricity and gas from National Grid);
- CfD (Clean Electricity) contractual requirements;
- Regulations (e.g. EU ETS reporting and PPC permitting) requirements.

Where possible, it is proposed that normal industry standard practice will be adopted for the PCCS project. However, there are project elements which are by their nature bespoke and first of a kind – for metering, these are principally associated with aspects of applying EU ETS and CfD. As far as possible, the philosophy has been to align these aspects with present industry and site practice and standards if no firm guidance presently exists.

3.5.1. Electricity and Gas Trading Metering

The metering requirements for trading electricity and gas in the UK are well established and defined and much of the required infrastructure is already in existence and is operated in accordance with required codes and standards.

Due to significant change of use compared with the existing grid connection circuits, new electricity meters are proposed for the PCCS project to measure:

1. Export of electricity from ST20 to the grid; and
2. Import of electricity from the grid to the CCCC plant.

The existing GT13 electricity export metering is acceptable for use in the PCCS project.

Since there is a single gas supply to the Peterhead Power Station site, it is necessary to differentiate between the gas consumed by the PCCS project and the gas consumed by GT11 and GT12, as these units will be traded separately. To achieve this, a fiscal accuracy meter will be installed on the GT13 fuel inlet line.

With the exception of the import of electricity from the grid to the CCCC plant, all of this infrastructure will be maintained and reported by SSE.

3.5.2. Contract for Difference (CfD) Metering Compliance Strategy

In addition to being paid for the net electricity exported by the Peterhead Power Station generating units which are associated with the PCCS project, the CfD mechanism provides an additional revenue stream associated with the generation of 'clean' electricity. The objective is that this would allow PCCS to be financially viable and compete against electricity generated from unabated fossil fuel or renewable sources of electricity generation.

Application of CfD to the PCCS project, considering a thermal power plant with an associated carbon capture plant, is a First Of A Kind project in the UK. The development of the metering arrangements required for the CfD is ongoing and will be established prior to commencing the Execute phase.

The 'clean' electricity which is generated by the project will be defined by a clean electricity formula and an associated 'clean energy calculation'. The project's 'clean' electricity is based upon the amount of electricity exported by the power plant but also considers greenhouse gas emissions, carbon capture efficiency and the amount of electricity which would have been generated by the power plant if it had operated in unabated mode.

In principle, clean electricity is defined as a fraction of the metered net electricity produced by the power generation units which are connected to the carbon capture plant. It is proposed that this fraction of electrical output take into account the following:

1. Deduction of any on site electrical demand which is separately imported from the grid (for the CCCC plant and / or power plant associated with supply of CO_2 to the CCCC plant); and
2. Deduction of a proportion of the gross generated electricity which is not deemed to be 'clean electricity' to reflect the fact that the carbon capture process does not capture 100% of the CO_2 produced by GT13 and also that other carbon emissions are produced as a result of the full chain CCS process – e.g. from the offshore diesel generators which produce electricity on the Goldeneye platform.

In calculating the proportion of the generated net electricity which is not deemed 'clean electricity', the following CO_2 equivalent emissions are subtracted from the CO_2 transferred from the capture plant to the pipeline transport system:

1. CO_2 produced by the auxiliary boiler which is used to supply steam to both the capture process and also the existing power plant usage which includes non PCCS project usage. This term has therefore been treated separately to allow an allocation factor to be applied to account for the portion of CO_2 emissions related to steam consumption which is directly attributable to the PCCS project; and
2. CO_2 which is not directly emitted on site by the PCCS project but was generated in the production of consumables which are used by the project.

To support the CfD clean electricity calculation it is necessary to install metering of the gross electrical output of the GT13 and ST20 units. It is also required to separately meter the gas consumed by GT13 and the auxiliary boilers, noting that these boilers supply a steam demand which is shared between PCCS and the other PPS infrastructure.

The CO_2 transported for storage is metered through a trade standard meter and compositionally analysed via a permanent on-line gas chromatograph before entry into the export pipeline.

The reporting requirements for the CfD are currently being developed and will be reviewed further during the Execute phase.

3.5.3. EU ETS Compliance Strategy

In the context of greenhouse gas emissions, the entire project (from CO_2 capture to storage) is required to be operated under the European Union Emissions Trading Scheme (EU ETS) and the philosophy follows the European Commission's published guidelines on monitoring and reporting. The guidelines imply reporting boundaries, requiring the elements of the CCS chain be reported separately. This has resulted in an increase in metering points across the chain when compared with the pre FEED design.

The FEED concept for PCCS compliance with EU ETS regulations proposes that the project be considered in segments as follows:

1. Peterhead Power Station (including existing GT11, GT12, GT13, ST1, new ST20 and auxiliary plant);
2. Onshore Capture Compression & Conditioning Plant; and
3. Offshore (comprising the offshore pipeline, Goldeneye Platform and geological storage).

To allow this reporting, in addition to the previously mentioned meters, it is necessary to meter the CO_2 flow in the inlet duct to the CCP booster fan, and the CO_2 flow in the pipeline as it enters on to the Goldeneye platform.

The main reason for deciding not to consider the project as a single entity under EU ETS was in order to align the project ETS permitting and reporting with the relevant regulatory bodies - SEPA and DECC. Similarly, the onshore assets have been assigned in accordance with their anticipated future ownership. SSE, who owns the present power station assets, will be responsible for reporting on these assets under EU ETS to maintain business as usual while Shell will be responsible for reporting for the new Carbon Capture, Compression and Conditioning (CCCC) plant equipment. For EU ETS compliance, the PCCS related generating plant, GT13 and ST20, will be considered as part of SSE's installation.

3.5.4. PPC Metering Compliance Strategy

The existing Peterhead Power Station site has a Pollution, Prevention and Control (PPC) permit. Compliance with the permit requirements is part of the site operating licence and is regulated by the onshore regulator (SEPA). A revised PPC permit requires to be developed for the PPS site as a result of the PCCS Project.

The Carbon Capture Plant is designated a regulated activity under Schedule 1, Part 1, Section 6.10 of the Pollution Prevention and Control (Scotland) Regulations 2012 and as such its operator is required to apply to SEPA for a permit to operate.

The present strategy is therefore to develop two separate PPC permits for the Peterhead Power Station site: one for the PCCS project infrastructure and a revision to the existing PPC permit for the existing infrastructure.

Under the Offshore Combustion Installations (Prevention and Control of Pollution) Regulations 2001, which implements the IPPC Directive (EC Directive 96/61) to combustion installations located on offshore oil and gas platforms, a permit is only required when an installation has a thermal input exceeding 50 MW(th). The combustion equipment on Goldeneye does not exceed this threshold and therefore a PPC permit is not required.

The onshore PPC permits will be finalised with the regulator prior to entering commercial operations and will be developed further during the Execute Project phase. In general existing emission points are being utilised on the project which allows the use of the existing meters. CEMS will be required to be installed to monitor the exhaust gas flowing to the 170 m stack.

Consideration of metering requirements to satisfy PPC requirements is covered in the Key Knowledge Deliverable 11.077 – Surveillance Metering and Allocation Strategy and Design Package [11]. The relevant contents of this document are summarised below.

The philosophy identifies the primary requirements to be satisfied by the proposed metering and monitoring arrangements across the chain. These requirements include compliance with relevant legislation such as the greenhouse gas emissions permits, other environmental permits and the requirements of the European Directive on geological storage of CO_2. Other requirements include demonstration of safe operations, and demonstration to DECC that the CCS Competition requirements to capture and store CO_2 are met. Metering will also be required to substantiate the consumables component of the cost of operation. The integrity of the transportation and injection system pressure parts and therefore the safety of much of the CCS Chain will rely on avoiding the increased risk of corrosion and other adverse conditions which can result from out-of-specification CO_2. The CO_2 composition analysers will play a significant safety role in providing the reliable continuous measurement required to ensure the correct CO_2 specification is maintained.

4. Key Project Performance Parameters

Key performance aspects of the project such as values for target performance parameters, and Reliability, Availability and Maintainability (RAM) figures were developed during FEED. This information has been used as inputs to the Minimum Functional Specification (MFS) within the Project Contract arrangements under development between Shell and DECC are summarised below.

4.1. Project Target Performance Parameters

Although Shell and DECC were in the process of negotiating the Project Contract for the Execute project phase, contractual arrangements were not finalised at the time of the HMG announcement. Therefore the performance guarantee figures proposed in the draft contract MFS had not been agreed and formalised contractually. The Project Contract included Target Performance Levels and Minimum Performance Levels which the project required to meet in order to pass a performance test and a commercial proving period and thereafter be remunerated during the project's operational phase. The Target Performance Levels (TPLs) and Minimum Performance Limits (MPLs) have been developed jointly by Shell and DECC to define the Project's target obligations. In the draft project contract, it was proposed that the Project be allowed to meet MPLs during commercial proving but that TPLs needed to be met during commercial operations. The performance targets in the Project Contract will be effective from completion of commissioning of the End-to-End CCS chain.

A summary of the TPLs and MPLs developed for the Peterhead CCS project, covering the power plant, the heat recovery steam generator, HRSG13 (including the Selective Catalytic Reduction (SCR) system) and the CO_2 transferred into the offshore transportation system is shown in Table 4-1.

Table 4-1: Target and Minimum Performance Levels (TPL / MPL)

Parameter	Units	Target Performance Level at 100% load	Minimum Performance Limit at 100% Load	
			Value	Minimum or Maximum limit
Gross electrical power	MWe	370.9	352.3	Minimum
Net exported electrical power	MWe	357.2	339.4	Minimum
Gross electrical heat rate	KJ/kWh	6748.8	7086.2	Maximum
CCP imported electrical power	MWe	34	40	Maximum
Power Plant Block 2 electrical parasitic power	MWe	6	7	Maximum
CO_2 entering the transportation system	TE/HR	128.3	90	Minimum
SCR NO_X Outlet (Dry basis not corrected for Oxygen)	ppmv	1	3	Maximum

Note that these performance figures are as predicted in December 2015 and may be adjusted ahead of signature of the Project Contract. Additional information on the electrical consumption can be found in Section 5 of the key Knowledge Deliverable 11.003 – Basic Design Engineering Package [8].

Target Performance Levels are quoted at 100% Load – i.e. generating plant output or process performance at reference conditions (based on Peterhead mean yearly average) as defined in Table 4-1. Commissioning tests performed for the CCS infrastructure during Execute will be corrected back to these conditions to compare actual performance against the reference parameters detailed in Table 4-2.

Table 4-2: Power Plant and Capture Plant - Project design reference conditions

Parameter	Units	Value or reference to supporting data and information
Atmospheric pressure	bar	1.013
Ambient temperature (dry bulb)	°C	8
Relative humidity	%	80
Wind speed	m/s	5.7
Cooling water temperature	°C	10
Frequency	Hz	50
Generator power factor	-	0.85

Parameter	Units	Value or reference to supporting data and information
MP steam transfer	kg/h	For 100% load operation of Capture and Compression Plant
LP steam transfer	kg/hr	For 100% load operation of Capture and Compression Plant
Fuel Gas		As per SSE's gas specification for the Peterhead Repowering Units.

Once the upgrade to the gas turbine has been completed the power efficiency, at on site conditions and without taking into account GT degradation over time, is calculated to be 57.1% (on a LHV basis) for the power plant with a calculated efficiency with the addition of the Carbon Capture and Storage operation of 47.6% based upon a 8°C reference case. These values are estimates developed at the end of FEED, and have been updated and would ultimately have been guaranteed by the EPC Contractor in the Execute project phase.

4.2. End-to-End RAM Analysis

During FEED, a Reliability, Availability and Maintainability (RAM) study was undertaken to create an End-to-End reliability model of the PCCS Project. The RAM study was used to quantify the overall reliability and availability of the project. The RAM model was also used to identify critical systems or components and events which caused significant plant downtime, determine where installation of redundancy would be most effective and present recommendations on how to achieve a target availability for the CCS chain of 80% or higher.

The power plant (GT13) availability providing flue gas to the project was a fixed input to the RAM model. The input availability data is summarized in Table 4-3, and the target performance parameters for the full CCS chain are summarised in Table 4-4. The calculated PCCS performance parameters are summarized in Table 4-6.

Table 4-3: Power Plant (GT13) Annual Target Availability

Year	Target Availability %	Man-hours for year
1	88.9	7788
2	87.6	7674
3	87.6	7674
4	89.2	7814
5	87.6	7674
6	87.6	7674
7	88.7	7770
8	87.8	7691

Year	Target Availability %	Man-hours for year
9	88.2	7726
10	89.0	7796
11	87.7	7683
12	87.5	7665
13	89.2	7814
14	87.5	7665
15	87.6	7674

Table 4-4: Target performance Parameters - annual availability factor

Yr. n following successful commissioning of the CCS Full Chain	Target CCS Full Chain annual availability factor %	Planned Downtime %	Unplanned Downtime %	Man-hours for year
Yr 1	79.5	13.2	7.3	6964
Yr 2	89.1	2.7	8.2	7805
Yr 3	89.1	2.7	8.2	7805
Yr 4	79.8	13.2	7.0	6990
Yr 5	88.0	3.8	8.2	7709
Yr 6	89.1	2.7	8.2	7805
Yr 7	79.3	13.2	7.5	6947
Yr 8	89.3	2.7	8.0	7823
Yr 9	88.5	3.8	7.7	7753
Yr 10	79.6	13.1	7.3	6973
Yr 11	89.2	2.7	8.1	7814
Yr 12	89.0	2.7	8.3	7796
Yr 13	77.2	15.6	7.2	6763
Yr 14	89.0	2.7	8.3	7796
Yr 15	89.1	2.7	8.2	7805

Table 4-5: Plant Availability

Year	Target Availability %	Man-hours for year
Power station plant	**96.66%**	8467
Carbon capture plant and first stage compression and conditioning	**92.87%**	8135
Transportation including the dense phase compression, onshore pipeline and offshore pipeline	**97.40%**	8532
Storage including the Goldeneye platform and wells	**97.92%**	8578

Table 4-6: CCS Project Key Availability Parameters

Key Performance Parameters	
Availability	85%
	312 days
Availability Losses	15%
	53 days

The annualised average availability for the PCCS chain over a 15 years operations lifetime is approximately 85 % as of December 2015. The highest contributors to the full PCCS unavailability are the PPS station outages for gas turbine GT13 scheduled maintenance.

The following factors are identified which may influence delivery capability.

Onshore

- Single export compressor;
- Single process vessels;
- Unplanned total shutdown of PPS leading to potential total shutdown of CCS Plant;
- Spares availability and longer turnaround time of equipment or component repair (notional mobilisation times and spares have been assumed);
- Unanticipated failure rate of valves and seals in CO_2 service;
- GT13 maintenance outage.

Offshore

- Single diesel tank installed on the platform (representing possible single point of failure for power generation etc.);
- Single deck crane, potential failure which may impact diesel bunkering;
- Closure or failure to operate Subsea Pipeline Isolation Valve and Associated Hydraulic functions;
- Unexpected changes in reservoir parameters (pressure, temperature, injectivity etc.);
- Hydrate formation during initial well injection caused by failure of methanol inhibition system;
- Limited availability of Standby Vessels to support offshore visits following an initiated emergency shutdown.

The table below displays the Global Reliability Loss and the Local Reliability Loss percent of each component in the PCCS chain. The stated Global Reliability Loss percentages provide the percentage loss for each element of the CCS chain with respect to the actualised loss stated in Table 4-6. The Local Reliability Loss is the percentage breakdown within each availability group considered within the RAM model. This allows the elements which have most impact on the CCS chain system availability to be clearly identified.

Table 4-7: Criticality

PCCS Full Chain	Global Reliability Loss%	Local Reliability Loss%
CCS Project 'Generation Facilities'	54.3	54.3
Station Outage	20.8	20.8
CCS Plant	20.7	20.7
Offshore	4.2	4.2
CCS Project 'Generation Facilities'		
Gas Turbine GT13	39.0	69.9
Steam Turbine system	10.7	19.7
Auxiliary Boiler System	2.4	4.4
Heat Recovery Steam Generator HRSG13	1.8	3.3
Selective Catalytic Reduction (SCR) sys	1.0	1.8
Seawater for cooling	0.3	0.6
Instrument / Plant Air (for Power Generation)	0.1	0.2
Electrical and C&I Systems	0.1	0.2
Demin-water Treatment Plant	0.0	0.0
CCS Plant		
CO_2 Compression	9.1	44.0
CO_2 Stripper, Amine recirculation system	3.1	15.1
Pre-Treatment Plant	3.1	14.8
Control Valves	2.6	12.6
CO_2 dehydration	1.8	8.5
Waste Water Treatment Plant	0.4	2.0
CO_2 Absorption Section, Water Wash Sect	0.4	1.7
Oxygen removal	0.2	1.1
Instrument / Plant Air	0.1	0.3
Offshore		
Goldeneye Platform	3.8	89.9
Valves and Subsea Pipeline	0.4	10.1
Goldeneye Platform		
Riser	1.2	32.8
PCV1	0.8	21.4
ESDV	0.8	20.7
ESDV Riser	0.8	20.5
Wells	0.2	4.7
S-01002A	0.0	0.0
S-01002B	0.0	0.0
ESD Leak Test	0.0	0.0
Power Generation	0.0	0.0

4.2.1. Upset Conditions

Upset conditions may occur either in the supply of flue gas to the CCS Chain or within the CCS processing, transportation and injection system itself. The consequence of any upset varies depending on its origin and duration. PPS upset conditions, excluding any obvious ones such as main power failure, may arise due to failure of individual elements such as GT13, ST20, auxiliary boiler system or HRSG13. For the CCS system, upset conditions are most likely to occur within the amine plant, compression and dehydration plant, or at the Goldeneye platform.

Restart times for any of these upset conditions are of varying duration with the longest stemming from a full PPS cold start whilst the shortest could be for a minor trip which is immediately reinstated.

The longest upset condition occurs during a cold start of GT13. Steam supply required for heating the CO_2 stripper (C-2002) will not be available until after GT13 and ST20 are operational.

Typical restart times are present in Table 4-8 below.

Table 4-8: Shutdown Indicative Re-start Times

Condition	Restart Time (mins)
GT 13 Cold Start	~ 90
GT 13 Warm Start>6<16 hrs	~ 60
GT 13 Hot Start <6hrs	~ 50
ST 20 Cold Start	~ 110
ST 20 Warm Start	~ 50
ST 20 Hot Start	~15
Condensate System	~ 20
CCS Amine System	~ 60 - 120
Compression and Dehydration	~ < 60
Goldeneye and Wells	~ < 60

In the event of an onshore disruption which limits CO_2 production, the design intent is to attempt to maintain the well tubing at its operating temperature, by forcing the control system to a minimum flow regime to preserve CO_2 pipeline volumes and to maintain tubing temperature, thus minimising the need to proceed through a well re-start sequence. It is estimated there is adequate line pack in the offshore pipeline to allow CO_2 injection operations to continue for approximately two hours at minimum flow, before the minimum operating pressure is reached and pipeline shutdown is required.

5. Health, Safety and Environment

Health, safety and environmental risks specific to PCCS Project were managed through compliance with Shell's internal Health, Safety, Security, Environmental and Social Performance (HSSE&SP) Management System procedures. These procedures have been developed to support project teams to identify, manage and integrate all aspects of HSSE&SP in the development of a Project, including identifying associated risks, managing them, and demonstrating that they are ALARP (As Low As Reasonably Possible). Many of the aspects of HSSE&SP are covered within the Onshore and Offshore Environmental Impact Assessments (EIAs).

Key findings from the HSSE reviews undertaken during FEED are summarised below with particular focus on the HAZard IDentification (HAZID), HAZard and OPerability (HAZOP), Control of Major Accident Hazards (COMAH) and Environmental activities that have been carried out, a more complete summary of the Health Safety and Environment activities undertaken during FEED are presented in the Key Knowledge Deliverable 11.120 – Health, Safety and Environmental Report [19].

5.1. HAZID and HAZOP Summary

HAZID is an identification of hazards or potential causes of harm to people, damage to property, or loss of Company reputation, with the aim of planning safeguards, control and mitigation measures, and recommending actions towards risk mitigation if the current Project proposed control measures are not deemed to be sufficient to control the hazard.

HAZOP is an analysis of a planned or existing process or operation using a structured, formal, systematic examination of the process and engineering intentions, in order to identify and evaluate hazards and problems that represent risks to personnel or equipment.

Separate HAZIDs and HAZOPs were conducted, over multiple sessions at different times during FEED, due to the fact that the drawings required (Process Flow Diagrams (PFDs), and Piping and Instrumentation Diagrams (P&IDs) were produced according to each FEED scope requirement and thus were ready for review at different times. Also, there were differing requirements for personnel to attend to ensure that suitable expertise was present. In order to ensure that the interfaces between the Onshore and Offshore designs are suitably managed, some individuals from each team attended multiple sessions In line with good practice the scope of each area's HAZOP included an overlap with the respective upstream and downstream area.
Each of the main reports covered a specific scope. These are:

- Onshore - Power Station Modifications;
- Onshore - Carbon Capture and Compression Plant;
- Subsea - CO_2 pipeline from downstream of the compressor to Goldeneye platform;
- St Fergus - Methanol scope located at St Fergus, including the methanol pipeline; and
- Offshore - Goldeneye offshore platform.

5.1.1. Objectives

The purpose of the HAZID study was to:

- Identify all potential causes of: harm to people, damage to property, or loss of Company reputation resulting from the Peterhead CCS Project;
- Record safeguards, control and mitigation measures which are planned to be in place for each HSE hazard; and
- Recommend suitable actions towards risk mitigation if the current Project proposed control measures are not deemed to be sufficient to control the hazard.

As part of the HAZID, a qualitative risk assessment was undertaken following Shell's internal management process to consider all aspects of the additional facilities on the existing SSE facilities during their construction, commissioning and operational phases.
The subsequent HAZOP sought to identify potential safety and operability problems within the design of the plant as represented on the Process and Instrumentation Diagrams (P&IDs) and/or other design documents and made recommendations for appropriate corrective actions.

These recommendations are targeted to achieve a reduction in the overall risk to people, the environment, the assets and Company reputation or operating cost/complexity.

5.1.2. Summary

In the HAZOP, hundreds of items were recorded and from these numerous recommendations were raised in relation to improvements in the management of hazards or to improve the understanding of the risk during the design.

The following sections summarise the HAZOP reviews:

5.1.2.1. Onshore Power Station

A total of 29 process nodes were reviewed and 415 actions recorded in relation to improvements in the management of hazards or to improve understanding of the risk during the design.

5.1.2.2. Onshore Carbon Capture and Compression Plant

A total of 44 process nodes were reviewed and 594 actions recorded in relation to improvements; in the management of hazards or understanding of the risk during the design.

5.1.2.3. Pipeline and Subsea

A total of 3 process nodes were reviewed and 35 actions recorded in relation to improvements; in the management of hazards or understanding of the risk during the design.

5.1.2.4. St Fergus

A total of 3 process nodes were reviewed and 28 actions recorded in relation to improvements; in the management of hazards or understanding of the risk during the design.

5.1.2.5. Offshore

A total of 7 process nodes were reviewed and 75 actions recorded in relation to improvements; in the management of hazards or understanding of the risk during the design.

Further information regarding HAZID and HAZOP report finding can be found in the Key Knowledge Deliverable 11.120 – Health, Safety and Environmental Report [19].

5.2. COMAH

In the United Kingdom, CO_2 is classed by the Health and Safety Executive (HSE) as a 'substance hazardous to health' under the Control of Substances Hazardous to Health Regulations 2002 (COSHH). The HSE publication 'EH40/2005 Workplace exposure limits' [1] provides Workplace Exposure Limits (WELs) for CO_2. WELs are limits to airborne concentrations of hazardous substances in the workplace and are set in order to help protect the health of workers. Workplace exposure is calculated by taking an average over a specified period of time. The WELs defined by HSE for CO_2 are:

- Long-term exposure limit (8-hr reference period) of 5000 ppm; and
- Short-term exposure limit (15 minute reference period) of 15000 ppm.

The HSE also states that:

"*In CCS operations it is likely that CO_2 will be handled close to, or above, its critical pressure (73.82 bara) where many of its properties are similar to that of a liquid. In this state it is often referred to as 'dense phase', whereas above* *critical temperature (31.04°C) and pressure it is referred to as 'supercritical'. Significant hazards associated with dense phase or supercritical CO_2 arise when pressure falls suddenly or is lost completely.*

CO_2 is not defined as a dangerous substance under the Control of Major Accident Hazards Regulations 1999 (COMAH) or as a dangerous fluid under the Pipelines Safety Regulations 1996 (PSR)."

In June 2011 HSE published the report "Assessment of the major hazard potential of Carbon Dioxide" [20]. This report concluded that CO_2, based on the evidence available at that time, has major accident hazard potential if released at, or above, its critical pressure. However, where the risks are properly controlled the likelihood of a major hazard incident is expected to be very low, as in other similar processes in the energy, chemical and pipeline industries.

More information can be found on the HSE website where the HSE advises that it is committed to keeping CCS risks under review and will consider extending existing major accident hazard legislation to cover CCS if this is justified by future evidence.

As a result, in order to mitigate the risk of HSE reclassifying CO_2 under future changes to the COMAH legislation, Shell has decided to treat CO_2 as if it were defined as a dangerous substance under COMAH in terms of regulatory engagement.

The COMAH regulations aim to limit the consequences of a major accident to people, local communities and the environment and are based on the quantities of what are termed 'dangerous substances' stored or in use on site or potentially generated during an accident event. The substances are either specifically named substances or categories of substances. A comparison of the threshold quantities specified in the Regulations and the quantities associated with the proposed activities on-site determines whether COMAH applies. Sites falling under COMAH regulations are classified as "lower" or "upper" tier dependent upon the quantities of designated 'dangerous substances' which are stored and used on a specific site, upper-tier being the more onerous with additional responsibilities and requirements for Operators.

5.2.1. Objectives

The objective of FEED COMAH review was to identify the maximum inventory of the chemicals used in the existing Peterhead Power Station site and proposed Carbon Capture, Compression and Conditioning plant. The chemical inventories were then compared against the COMAH specified thresholds to determine whether the site falls within the scope of current recently published COMAH 2015 Regulations. The new regulatory requirements under COMAH 2015 were also reviewed and their implications for the Project considered.

5.2.2. Summary

PPS does not presently qualify as a COMAH site (under any tier definition) under the COMAH 2015 Regulations. Following the modifications that would be required for it to be ready for operation to supply the CCS plant, it is considered that the status of PPS would not change. This is because of the limited change to the site aggregate scoring that result from the modified diesel and natural gas inventories of the new auxiliary boiler house and the new vanadium pentoxide catalyst required for the SCR unit.

Based on the consultation document on the COMAH Regulations 2015 [21], the CCCC plant when operational, would qualify as an upper-tier COMAH site because it is anticipated that the combined amount of process chemicals in the Thermal Reclaimer waste product will be in excess of 5% by weight and more than two tonnes of inventory at any one time. The COMAH review concluded that the proposed CCCC plant would be the sole reason for the COMAH Regulations applying to the Project. This will be taken into account in determining how the existing and proposed PPS facilities will be treated – i.e. whether they will be a combined establishment with a single operator or two separate plants with separate operators.

Additionally, according to current interpretation of application of the COMAH Regulations, the fresh and circulating amine inventories were classed as dangerous substances under the 1999 Regulations but not under the recent 2015 Regulations. There is therefore uncertainty over the classification of these substances and tests were ongoing at the time of production of this document to analyse the likely impact of released amine – for example with regard to marine life. Until firm clarification on the proposed 2015 Regulations is available, the fresh and circulating amine inventories are being considered in accordance with the 1999 COMAH regulations as good practice and are being considered as having Major Accident Hazard potential.

In a similar vein, whilst CO_2 is not classified a dangerous substance under either issue of the COMAH Regulations it does have major accident hazard potential for personnel working on site, either inside the compressor house or in the vicinity of the dense phase pipework and pipeline. CO_2 has therefore also been included within the MAH list for the facilities.

5.3. Environment

Key findings from the environmental assessment undertaken during FEED are summarised below.

Two types of significance criteria were used in the assessment:

- Impacts associated with emissions from the Project only; and
- Impacts associated with the Project added to the existing background conditions.

The assessment was undertaken in accordance with the following guidelines

- For sensitive human receptors for the purposes of EIA, the guidelines set out by the Institute of Air Quality Management (IAQM) were used; Institute of Air Quality Management (2010) Development Control: Planning for Air Quality [22];
- For the purposes of Pollution Prevention and Control (PPC) Permitting, the guidelines set out in the SEPA H1 guidance were used; SEPA (2003) H1, Environmental Assessment and Appraisal of BAT, Updated, July 2003 [23]; and
- For sensitive ecological receptors, for both EIA and Permitting the H1 guidance was also used.

5.3.1. Effects Considered in Environmental Assessment

The following pathways with potential to have a likely significant effect were identified in the Onshore and Offshore EIAs:

- Gaseous emissions;
- Discharges to water (planned and accidental);
- Accidental release of CO_2;
- Waste generation;
- Physical disturbance during construction including;
    - Disturbance from vessels;
    - Indirect construction effects on foraging seabirds through suspended solids;
    - Temporary and permanent habitat loss;
- Noise; and
- Lighting.

5.3.2. Gaseous Emissions

With regard to sensitive ecological receptors, following the H1 guidance European sites within 15 km of the Peterhead Power Station (where emissions will originate) are considered.

The Onshore Environmental Statement (ES) reports that as a result of the existing baseline and the contribution from the Peterhead Power Station some Critical Levels and Critical Loads provided in the SEPA guidance documentation are exceeded at the Buchan Ness to Collieston Coast Special Areas of Conservation (SAC). In the case of acid deposition and nutrient nitrogen deposition the baseline deposition is in some cases in excess of the Critical Loads.

Future operations following completion of construction and installation of the Project are predicted to result in an overall decrease of around 30 % in impacts at all sensitive ecological receptors, due to the reduction in emissions of NO_X. However, the Critical Levels and Critical Loads at the Buchan Ness to Collieston Coast SAC are still predicted to be exceeded. As discussed in the Onshore ES NOx emissions are reduced due to the introduction of the Selective Catalytic Reduction system (SCR), NO_X absorption in the CCS and the use of the 170 m stack to discharge the emissions from the CCS project will aid dispersion.

The Onshore ES indicates that air emissions, including amines and nitrosamines will be subject to approval by SEPA in relation to human health, and therefore no significant impacts on qualifying seabird species associated with the Buchan Ness to Collieston Coast SPA are predicted given the application of these high standards. Air quality modelling indicates that NO_X, nutrient nitrogen and acid deposition will be lower with the installation of the CCS operations and therefore there will be no significant effects on qualifying habitats of the Buchan Ness to Collieston Coast SAC.

The reduction in total emissions and controls on amines and related compounds indicates there would be no likely significant effects on any European site.

The Offshore EIA determined that emissions via the offshore works, including installation and supply vessels, flotel, well workover rig requirements and platform operation, are of negligible significance. Specifically, the emissions are of comparatively low volumes and will be localised and readily dispersed. In addition all Goldeneye works are out with the 15 km radius of any European sites. As such there would be no likely significant effects on any European site. More information can be found in the Peterhead-CCS-Project-Offshore-Environmental-Statement [24].

5.3.3. Water Consumption and Discharge

Discharges to sea, such as chemicals and hydrocarbons, can result in impacts on water quality and consequently mobile qualifying features of European sites through toxic and bioaccumulation effects. The European sites and mobile qualifying features which are considered, due to connectivity with potential discharges to sea from the project, are the Buchan Ness to Collieston Coast SPA 2 km Marine Extension for birds and the Moray Firth SAC for bottlenose dolphins. All project discharges will have a no more than localised impact, therefore all other European sites are excluded from further consideration due to lack of connectivity.

5.3.3.1. Service Water and Potable Water Systems

Service water and potable water are provided by the existing Power Plant water systems.

Service water is required for various processes and purposes in the CCCC plant. Potable water is used for drinking water supply and for supplying emergency showers, eye baths, control room building facilities, toilets, etc.

The continuous users of town's water are the vacuum package purges in the thermal reclaimer and dilution of the degraded amine, although the capacity of the system is designed for 29 m^3/h to provide the capability of filling the direct contact cooler and safety showers/utility systems.

Finalisation of the number and location of utility buildings and other consumers will take place during Detailed Design. The peak flow for filling these process users is estimated at 11 m^3/h.

The town's water supplies are taken from the power plant main water supply via a break tank.

Water of drinking quality is supplied to meet the potable water requirements of regular and shift staff, visitors, safety showers and safety eye wash stations. The total maximum potable water consumption is estimated at 15 m^3/h (including 10 % margin); based on two safety showers operating simultaneously. Potable water supplies come directly from the existing SSE main supply. A more detailed analysis of the water consumption can be found in Section 6.5 the Basic Design and Engineering Package 11.003 [8].

5.3.3.2. Power Station Discharges

The Project proposes to use the existing Power Station outfall pipe, comprising two 300 mm diameter open ended pipes approximately 800 mm apart capable of handling a maximum flow rate of 360 m^3/h each. Both pipes discharge horizontally into the intertidal zone, being submerged at high tide but exposed at lower states of the tide. Effluent is discharged in the same direction as the adjacent cooling water discharge, which is approximately 20° north of west.

The effluent density during operation is expected to be effectively constant at 1.0 kg/l and will create an area of turbulence in the water column in the immediate vicinity of the outfall pipe. Cooling water, required by the Project, is proposed to be drawn from the sea at Boddam Harbour (south of Sandford Bay), and discharged at low water from cooling water discharge pipe, directly adjacent to the effluent discharge pipe. The discharged cooling water has an elevated temperature and higher chlorine concentrations than the receiving water. All existing discharges to Sandford Bay have permits and meet SEPA's consent values for discharge of effluent to the marine environment.

Assuming a worst case scenario, combined effluent discharge modelling was undertaken to help predict potential impacts from the Project discharge. Modelling results predict that the proposed combined discharge of treated effluent is not likely to form any toxic zone around the outfall itself (considering amines, ammonia, nitrates, nitrites, pH, TDS and dilution) and that all regulatory standards will be met at the edge of the mixing zone at 100 m from the outfall. As a result, no significant effects to the Buchan Ness to Collieston Coast SPA marine extension and SAC or the mobile features of the Moray Firth SAC, bottlenose dolphins, are expected.

5.3.3.3. Pipeline Installation and Discharges at Goldeneye

The Offshore ES reports that during pipeline installation and Goldeneye works (both installation and operation), discharge of sewage, food waste and deck drainage from support vessels will occur; however, these discharges will be in line with regulatory requirements and are not considered significant due to the small volumes. They are therefore considered not likely to have a significant effect on the qualifying features of the Moray Firth SAC (bottlenose dolphin) and Buchan Ness to Collieston SPA (seabirds).

For the HDD landfall solution, a small volume of drilling mud, bentonite (a natural clay), will be discharged to sea. The majority of the bentonite used will be transferred, with the drill cuttings, back to shore. However the top 2 m of sediment before the push through to the seabed (c.5-10 m of hole length) will be discharged at the HDD exit point (c.800 m from shore). Based on a 32" [812.8 mm] hole diameter, this equates to c.5 m3 discharged. As bentonite is heavier than water, the majority of the bentonite and the cuttings will sink to the seabed and solidify. As such, impacts will be confined to the immediate benthic community. This could result in minor indirect impacts to the mobile features of European sites via impacts to food sources. However, the affected area would be very small in comparison with available feeding grounds. As the discharge will be in a relatively high energy area some of the bentonite is expected to suspend in the water column and disperse, reducing the volumes smothering the seabed.

During pipeline tie-in there may be small discharges, for example dye sticks. Environmental impacts of such discharges are considered negligible due to small volumes discharged and dispersion within the water column. No operational discharges from the pipeline in nearshore waters are envisaged. All pipeline cleaning fluids will be discharged at Goldeneye. Impacts associated with all discharges from Goldeneye will be temporary and localised, thus no likely significant effect to any European sites is predicted.

Therefore, no likely significant effect from the Project is predicted for the mobile qualifying features of the Moray Firth SAC (bottlenose dolphin) and the Buchan Ness to Collieston SPA (seabirds).

6. Risk Management

The purpose of risk management is to achieve business objectives, safeguard company assets from inappropriate use, loss or fraud, facilitate safe operations and enable compliance with the boundaries set by the Shell Control Framework. Subsets of Business Risk are, for example Health, Safety, Security and Environment (HSSE), Opportunity, Project, Operations, Reputation, Legal, Tax, Commercial and Financial risk. The focus of project risk management is to identify, manage and report the full spectrum of upside and downside risks that may drive top quartile project execution and delivery.

The objective of project risk management activities is to provide information to decision-makers while they select the most appropriate concept, perform basic and detailed design work and manage the project through execution. Risk management integrates input from the risk register (both upside and downside risks), cost estimate and schedule into a probabilistic risk analysis to provide ranges of possible outcomes of final cost and schedule along with the key drivers that may impact the project.

These risk assessment impact categories are aligned to the risk metrics used by DECC. The top Risks at the start and end of FEED are also detailed in Appendix 2 and 3. Further information can be found in the Key Knowledge Deliverable 11.023 – Risk Management Plan and Risk Register [25].

6.1. Mitigation strategies for Top 5 CCS-Specific Risks

Certain risks recorded in the project risk register are characterised as unique to this project, and reflect the uncertainties associated with the First-Of-A-Kind (FOAK) technology involved in each chain link of the project. These risks have been categorised as “CCS-specific”. The Top CCS-Specific risks at the end of FEED phase are summarised below:

Table 6-1: Top CCS-Specific Risks

Risk Title	Risk Description	Mitigation Strategy
High Solvent Degradation	Degradation/ make-up rates can be calculated but not proven since no similar capture plant using the same solvent has been built and operated at this scale). Therefore degradation and make-up rates could be higher than anticipated. Consequence: increased OPEX risk affecting the economics of the project negatively; increased waste disposal requirements; plant required	In order to mitigate the risk, additional testing on the solvent was performed at the Mongstad (TCM) pilot facility in Norway. Indications are that the results obtained provide increased confidence that the PCCS CCP should operate within the allowed design margins.

Risk Title	Risk Description	Mitigation Strategy
	to run at lower capacity to limit degradation rate.	
Higher corrosion in wells than expected	The combination of ions in the water caused by CO_2 interactions and the possible occasional presence of oxygen could react with the metal and cause corrosion and failure of the well components.	The risk will be mitigated as much as possible by selection of appropriate well components to minimise corrosion risk, performing corrosion experiments and adopting a suitable sparing strategy. Other mitigating actions being considered include performing Well Cat modelling, integrity logging during workover.
Emission of nitrosamines and other degradation products	Emissions and other degradation products from the onshore CCP potentially represent a perceived health risk.	The key mitigation actions were captured in the FEED design for the project after a Health Risk Assessment was completed; with more conservative emissions limits assumed than legislatively required. The modelling assumptions were tested and accepted by SEPA, and reflected in the onshore planning application which was the subject of three phases of public consultation with the local community; Planning permission was approved by Aberdeenshire Council.
Performance of Waste Water Treatment Plant (WWTP) based on FEED design	In order to treat waste water streams from both Shell and SSE facilities to meet discharge limits, the specialist FEED contractor designed a WWTP solution which was larger than originally envisaged with additional concerns raised over operability, discharge limits as well as construction cost/schedule.	A small project team within Shell was created to look at the various options to reduce the size and complexity of the FEED design offered. The views of Shell subject matter experts in water treatment were captured as input to the project scope. These options ranged from looking at optimising the biological solution to transporting the waste product offsite for incineration, with the final conclusion reached for an optimised biological solution. This risk will be further mitigated during the detailed engineering phase by the EPC contractor responsible for the Onshore CCCC scope.
Scaled-up technology does not perform as expected	Scale-up of the CO_2 capture technology has not been proven and does not perform as expected or modelled once scaled-up. The cool-down/warm-up time is excessive. Could result in: Reduced injection volumes, Operating Cost Increases.	The system has been designed to have sufficient margin to cover likely scale-up issues to reduce the probability of poor performance. A continuous mitigation action is to apply lessons from Mongstad (TCM), Saskpower at Boundary Dam, Quest and other CCS projects around the world as the project progresses, and also apply learnings from similar industries such as SO_2 capture systems.

6.2. Insurability of risks and conditions/terms of insurance

The insurance strategy for the Peterhead CCS project has been documented in the Key Knowledge Deliverable 11.148 – Insurance Plan [26]. The main features of the Insurance Plan are:

- Shell will, in consultation with DECC, put in place a robust and cost-effective insurance programme to provide appropriate cover for both the Construction and Operational Phases of the CCS project. Shell envisage only placing insurance with insurers that meet minimum financial security requirements (being Standard and Poor's (A-) or equivalent by other rating agencies).
- The cost of risk, often materialising as insurance spend, during the lifecycle of a CCS project will present a significant cost to the venture. Implementation of a specific Project Risk Engineering Strategy is planned to reduce the overall "cost of risk" to the CCS project venture through effective Risk Engineering techniques including a Design Phase Risk and Insurance Review (DPRIR), and Risk/Insurance Underwriting and Loss Control Surveys.
- A Design Phase Risk and Insurance Review (DPRIR) will be conducted to identify and review the hazards, risks and risk controls associated with the design, construction (modification), commissioning, operation, closure and decommissioning and the post-decommissioning phases of Shell activities associated with the Peterhead CCS project. The principal focus is on the various loss exposures for property damage, liability and production interruption including well control liabilities.
- The Insurance Plan lists various known and identified risks through various stages of the project life and provides assessment and possible insurance solutions or explains lack of solutions via standard insurance risk transfer methods.
- Insurance cannot be procured upfront for the whole lifecycle of the project, thus availability, price and terms and conditions of coverage may vary over time, especially if claims occur. A key constraint of insurance for CCS projects is the term of available insurance as insurance policy periods are generally short term. This means that policies are issued for up to a maximum number of 2/3 years.
- Separate insurance solutions are required in order to facilitate the management of risk for the full CCS chain, defined over 4 key phases:
    1) Design and Construction;
    2) Operation;
    3) Closure and Decommissioning; and
    4) Post-Closure monitoring and maintenance.

- Coverage may be very expensive and/or restricted for the "novel" aspects of the project (CCS liability, financial risks of repurchase of carbon credits, subsurface migration/pollution, etc.).
- Until the regulatory regime is defined, it is uncertain what the extent of liability for CO_2 release is. At present, no requirement for re-purchase of credits or financial penalties is expected in case of accidental CO_2 release from the reservoir. Protection against repayment of carbon credits (European Union Allowances - EUAs) is currently uninsurable.

6.3. Risks in utilising existing plant or plant elements

The risks involved in utilising existing plant or plant elements have largely been addressed directly by SSE as the power station owner, or indirectly via the Onshore FEED Contractor's deliverables which addressed both the onshore carbon capture and power station scopes. Some of the key risks can be categorised into the following areas:

- **Existing site systems outside original design life and/or shorter than PCCS Operating Term**
  There is a risk that the existing site infrastructure which is planned to be used to supply utilities to the carbon capture process is not fit for purpose over the required lifetime of operation, resulting in requirements for repair / replacement and potential exposure to liabilities for loss of availability. The risk has been mitigated via the FEED Contractors who assessed the suitability of the existing plants before considering necessary upgrade and life extension works. A series of site assessments (civil, electrical, mechanical, controls/instrumentation, rotating equipment) were also completed by SSE, which provided sufficient certainty that the systems were suitable for the required PCCS operations period.

- **Incompatible interfaces between Carbon Capture Plant and Power Station**
  There is a risk of incompatibility of interfaces at the battery limits between the CCCC Plant and the existing Peterhead Power Station service systems, resulting in cost and schedule overruns. This risk has been mitigated during FEED by appointment of a single FEED Contractor for both scopes and joint development of the Battery Limit Schedule and Interface Schedule, which determines the interface points for the various CCS chain links as well as responsibility for executing work scopes (included in the design documentation and shared with the EPC contractors). Further focus will be placed on effectively managing interfaces between the project stakeholders (specifically Shell, SSE, Cansolv and EPC contractors) during Execute.

- **Impact of CCP Construction on existing Site Operations**
  Construction works will be completed whilst Peterhead Power Station maintains full operations. There is a risk that construction impacts on business-as-usual operations (potentially performance impact) at PPS which leads to loss of availability of Block 1. This risk has been mitigated by the execution of constructability reviews with Shell, SSE and FEED contractor staff, integrated schedule management with the power station on planned shutdowns and also included in the ITT packages sent to the Execute EPC contractors.

- **Impact of over-pressurisation on Heat Recovery Steam Generator (HRSG), or Selective Catalytic Reducer (SCR) impact on HRSG**
  There is a risk of over-pressurisation of the HRSG due to operations of the CCP such as booster fan high over-speed due to blockage in the flue system. This would potentially result in asset damage (HRSG casing) and consequential costs for repair. This risk has been mitigated by including the modelling and assurance of the process control system to ensure that it will protect the HRSG and GT in the FEED design, and ensuring appropriate QA process in place during detailed engineering to ensure good design.
  There is also a risk that the installation of SCR affects plant performance and leads to loss of availability payments and although HRSG13 has been designed as 'SCR ready' with an appropriately-sized spool piece for an SCR reactor at an appropriate flue gas temperature, initial visual inspection suggests that installation may well be difficult. This risk has been mitigated within the FEED design by ensuring the SCR impacts on performance are well understood and externally assured by a specialist vendor undertaking a feasibility study including some limited assessment of construction issues. The SSE Civil Team have also undertaken a high level assessment of the loading on the existing super-structure and based

on current information re loads, it is expected that they are within the capacity of the structure.

- **Supply of utilities to carbon capture plant impacts power station operations (including potential encroachment with live HV cables)**
  As the CCP will require utilities from the power station, SSE will be contractually required to supply utilities to the CCP. There is a risk that designs are not robust enough and utilities cannot be provided by the existing station, which may compromise the operation of the existing power station. This risk has been mitigated by ensuring that the design for utilities is adequate in the FEED design, including agreed utility requirements to be determined and quantified for demand planning between Shell and SSE.
  There is also a risk of encroachment with live HV cables associated with Block 1 or station supplies during excavation works. This risk is being mitigated by discussions to agree site segregation and construction sequencing between Shell and SSE, and will lead to routing cables away from existing HV cables where possible and also limiting the working areas near existing HV cabling.

- **Shared water treatment facilities for carbon capture plant and power station, including provision of cooling water for CCP**
  SEPA have stated that they view the power station and CCP facilities as one site, albeit with different emissions and discharge permits for the different parts and operators. For discharges to sea they have an expectation that the power station discharge will be treated with the capture plant effluent in the new water treatment facilities. The risk materialised that SEPA determined that the existing power station waste water must be treated via a new combined Waste Water Treatment Plant (WWTP), which necessitated significant changes to the existing power station drainage systems at significant additional cost. This has been incorporated in the design requirements for a combined WWTP, with the final solution still under review as the initial design proposed by the specialist FEED subcontractor was considered to be large, technically complex and expensive.
  There is also a risk that the installed water treatment plant at the power station cannot supply water of an appropriate quantity and quality for the life-time of CCS operation. This risk was mitigated by undertaking an assessment of the existing waste treatment plant to determine spare capacity and quality of treated water, with a plentiful supply of spare capacity confirmed.

- **Existing pipeline has unacceptable levels of corrosion**
  There is a risk that excessive levels of corrosion have occurred in the pipeline prior to injection, making the existing pipeline unsuitable for CO_2 service. This would impact the cost and schedule of the project as the corroded section of pipeline would have to be repaired or replaced. The risk has been quantified as very low based upon analysis of production and corrosion inhibitor injection history, prediction from corrosion models and the lack of any corrosion products recovered during the cleaning and flushing operations conducted as part of the recent hydrocarbon freeing process. A final intelligent pig run will be conducted 9 months prior to commissioning to confirm the integrity status of the pipeline at that time.

6.4. Other Risks causing possible significant delay

All of the risks in this section have been assessed as Low or Very Low in likelihood, but are considered to have the most significant potential for delays to the Project schedule:

- **Horizontal Directional Drilling (HDD) not possible**
  There is a risk that horizontal directional drilling (HDD) is not possible due to the conditions of the soil, as fractured granite would cause the borehole to collapse. This risk has been mitigated by completing borehole surveys during FEED, undertaking an external review of these surveys by a specialist vendor and completing an open cut alternative FEED in the event HDD is unsuccessful. In addition during FEED, a pilot hole was drilled to almost full length of the final hole, which provided more certainty that the ground conditions will allow successful HDD. In the event the risk materialises, the open cut alternative will be adopted which is estimated to impact the schedule by six months.

- **Goldeneye integrity issues prior to first injection**
  Although the condition of the infrastructure is well understood and characterised to be in good condition, there is a risk that new integrity issues could be uncovered during the construction activities, which may require extensive remediation activities with significant cost and schedule impacts. The risk has been mitigated by performing extensive surveys on the existing infrastructure, with further work planned to ensure the integrity planned before and during the start of the construction period. In the event a significant issue is discovered that requires immediate corrective action (e.g., pipeline section replacement, well remediation, etc.), it is estimated that this could impact the schedule by six months.

- **Unable to qualify rig for CO_2 intervention**
  A lack of industry experience for CO_2 offshore drilling rigs means that the scope of modifications required for safe operation on a pure CO_2 intervention is currently uncertain. Early works to mitigate the risk have included a feasibility assessment with specialist rig qualification companies to identify the requirements for rig qualification and, for wireline interventions, working with Schlumberger on Decateur onshore experience in the United States. In the event that a suitable rig cannot be secured for CO_2 intervention, a corrective measure of refitting an alternative rig could potentially result in a delay to the schedule of six months.

- **Redesign should the Competent Authority not agree that COMAH requirements have been suitably addressed in the project design**
  If the Competent Authority does not agree that the COMAH requirements have been addressed in the project design, it is possible that a redesign plant would be required. This would increase cost, delay schedule as well as damage stakeholder relationships and reputation. Mitigation actions include requirements being incorporated into the Onshore CCC EPC contractor's contract to complete the COMAH report as part of their scope, and for Shell to complete assessments on possible combustible products as well as toxicity assessments on the solvent and associated degradation products. In the event of this risk materialising during the engineering phase of the project, it is estimated that this would result in a four to six month delay to the schedule.

6.5. Risks and mitigations associated with consents

At the end of FEED, it is envisaged that risk and uncertainty will still exist in relation to three main consents required by the Project. Each of these risks is described in detail below, including the mitigation strategy employed to reduce the risk to an acceptable level.

1. **Carbon Storage Permit will not formally be in place before Shell FID**
   The formal award of this permit is not expected until Q1 2016, which is after the planned Shell Final Investment Decision (FID) date for the project. In light of the assurance provided by the British Geological Society (BGS) external review on the Goldeneye store, the work done by Shell to develop the Monitoring Measurement and Verification (MMV) plan and extensive dialogue between Shell and the Competent Authority (DECC EDU/OGA) including the work done to agree the technical and commercial principles for the permit award, and also taking into account that Shell will receive feedback from the EU panel throughout the review process, a positive FID decision may still be given by Shell's Executive Committee on the condition that no significant changes are mandated in the formal permit award by the Secretary of State. Shell will continue to work closely with the various regulatory and advisory bodies to ensure a successful outcome for all parties prior to the start of the next phase.

2. **REACH registration by Cansolv for solvent use in Europe**
   It is now expected that Cansolv will be unable to secure REACH registration for the solvent to be used in the Peterhead CCS project in line with the current Shell FID schedule. The Shell project team will continue to support their Cansolv counterparts to accelerate the registration process as much as possible, in particular in completion of the chemical registration dossier and any other documentation required to complete the process.

3. **Pollution prevention and control (PPC) permit challenged by regulators**
   The risk exists that SEPA requirements for Pollution Prevention and Control may be more onerous than the current FEED design, and at the time of application for the PPC permit, redesign may be required after completion of the Detailed Design phase. This would result in significant cost and schedule impact, and even lead to a possible resubmission of the onshore planning application. In order to mitigate this risk, extensive efforts have been made by the Shell project team to engage SEPA, provide them with data relevant to the proposed design and incorporate their views on what is Best Available Technique (BAT) and/or ALARP (As Low As Reasonable Practical) in the project design, which have been also been incorporated in the onshore planning application approved by Aberdeenshire Council. This also includes the SEPA recommendation for a combined water treatment plant for joint power station and CCP use. The Project team will continue to work with the regulators in order to ensure a smooth process towards the award of the PPC permit.

6.6. Novel Technology Risks and Further Research Requirements

Whilst very few of the individual elements of the Project are novel, the integration of on/offshore, brown/greenfield elements, upstream/downstream methodologies partnering with a power company, a complex commercial construct mixed with visible public exposure make the project largely driven by non-technical factors. The novel technologies that have been developed for the project can be found in Table 6-2, and the list of technology that is still in development or is still to be developed for the project can be found in Table 6-3. A more detailed examination of the novel technology used in the project can be found in the Key Knowledge Deliverable 11.064 – Technology Maturation Plan [10].

Table 6-2: Novel Technology List

Description	Status	Purpose
Large booster fan in flue gas duty	Developed	Economics, Operations.
Large Cansolv pre-scrubber and absorber	Developed	Economics, Operations, Construction.
Rotary type gas/gas heat exchanger for flue gas service	Developed	Economics, Operations.
Liner in large pre-scrubber and absorber units for flue gas services with new amine solvent	Developed	Economics, Construction.
Application of Cansolv amine solvent	Developed	Operations, Reputation, Economics.

Table 6-3: Technology and Procedures List

Description	Status	Purpose
Assessment of cement stability in downhole CO_2 environments	To be continued in Execute	Operations.
Seabed Leakage identification and quantification	To be developed in Execute	Regulation, impact on license or environment.
Tracer selection and addition/CO_2 fingerprinting	To be developed in Execute	Monitoring of CO_2 storage.
4D streamer in combination with Ocean Bottom Nodes (OBN) application	To be developed in Execute	Monitoring of CO_2 storage.
Geochemical probe (Conductivity, Depth and Temperature – CDT – & CO_2 saturation)	To be developed in Execute	Monitoring of CO_2 storage.
Subsurface Safety Valve for CO_2 Injection	Development ongoing	Operations.
Pressure Control Equipment for Well Intervention	To be developed in Execute	Operations.
Rig Qualification for CO_2 intervention	To be developed in Execute	Operations.
Tubing Material Selection	To be developed in	Operations.

Description	Status	Purpose
	Execute	
Impact of Contaminants in CO_2 Stream	To be developed in Execute	Operations

7. Permits and Consents Register

The Peterhead CCS Project will require a range of permits and consents, from various regulatory authorities, throughout the design, construct, operational and decommissioning phases of the Project. A Permits and Consents Register detailing all permits and consents believed to be applicable throughout the design, construct, operate and decommissioning phases of the Project has been developed that covers the full chain i.e. capture, compression, transportation, injection and storage. This can be found in the Key Knowledge Deliverable 11.030 – Permits and Consents Register [27].

7.1. Key Permits and Consents Progressed During the Feed Phase

The following permits and consents have been identified as being key to the development of the Project during the FEED phase. Those permits and consents that are normally associated with large industrial developments that are not applicable to CCS activities, or the Project specifically, are also listed.

- Key onshore permits and consents:
    - Section 36 under the Electricity Act 1989.
    - Planning Application under the Town and Country Planning (Scotland) Act 1997 as amended by the Planning etc. (Scotland) Act 2006.
    - Environmental Impact Assessment under the Town and Country Planning (Environmental Impact Assessment) (Scotland) Regulations 2011.
    - Pollution Prevention and Control (PPC) permit under the Pollution Prevention and Control (Scotland) Regulations 2000.
    - Safety Report under the Control of Major Accident Hazard (COMAH) regulations 2015.
    - Pipelines under the Pipeline Safety Regulations 1996.
    - St. Fergus permits and consents scope for the change to methanol service.

- Key offshore permits and consents:
    - Agreement for Lease under the Energy Act 2008.
    - Carbon Storage Licence under the Storage of Carbon Dioxide (Licensing etc.) Regulations 2010.
    - Environmental Impact Assessment under the Offshore Petroleum Production and Pipelines (Assessment of Environmental Effects) (Amendment) Regulations 1999 (as amended 2007 and 2010).
    - Pipeline Lease from the Crown Estate.
    - Safety Case under the Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015.

8. Key FEED Decisions

The Opportunity Realisation Process (ORP) is Royal Dutch Shell's (Shell's) approach for managing opportunities such as capital projects, acquisition/divestment opportunities, infrastructure investments or "integrated" opportunities.

Within the ORP process, Shell applies a standard Management of Change (MoC) process to projects which is applied appropriately throughout the difference stages of a project:

- Pre-FEED: Change is considered healthy but needs to be managed;
- FEED and Execute: Change should be kept to a minimum with a "No Change" mindset encouraged across the project delivery team.

In general, no change should be considered after commencing FEED unless it is as a result of the following conditions:

- The project is unsafe;
- The project will not deliver on its objectives, including operability; or
- Change is necessary to meet statutory requirements.

During FEED there were numerous decisions that had to be made across the whole project, stemming from the contracting strategy to the design life of the project as a result of the project evolving and developing. Many of the decisions, although not specifically First-Of-A-Kind (FOAK) CCS issues, required more consideration than if the project was applying more mature technology. A summary of the key decisions made during FEED is provided in Table 8-1 below.

Table 8-1: Key FEED Decisions Summary

Decisions Identified	Comments
BOO / Contracting Strategy	Various contracting strategy models were considered during FEED for implementation during Execute. One such option was the Build-Own-Operate (BOO) model. BOO is a form of project financing where the Contractor is responsible for the design, construction and operation of a facility – enabling the Contractor to recover its investment and operating and maintenance expenses directly from the project. Considerable more risk is apportioned to the BOO contractor compared to a normal EPC contracting strategy. In a BOO arrangement, ownership remains with the project company which gets the benefit of any residual value in the project. A BOO scheme involves large amounts of finance and a long payback period. Shell approached the market to determine if there might be interest in a BOO development approach. However, none of the tenders responses received was sufficiently competitive for this contracting strategy to be selected. During FEED the selected preferred contracting strategy for Execute was to develop the Execute construction and commissioning scopes under five separate work packages, with the major construction scopes managed under EPC contracts with overall project management provided by Shell.
Design Life	A 10-year operating period was originally proposed for the PCCS project as a result of the stated remnant life of the existing GT13 after completion of a major overhaul prior to commencing PCCS operations. However, all of the other new facilities

	provided under the PCCS project will have an inherent design life in excess of 15 years. Therefore, an extension of the GT design life was considered in FEED. The Siemens SGT5-4000F machine installed at Peterhead was an early installation of this type of GT design and therefore although it is normal practice to consider life extension for such GTs, there is presently insufficient information available to provide certainty in terms of scope and costs for such life extension works. This will be reviewed in more detail during operations and once life extension knowledge has developed further across the existing Siemens SGT5-4000F fleet of units.
No. of Wells	The philosophy pre-FEED was to recomplete all five of the existing Goldeneye production wells and retain them for future use for CO_2 injection under PCCS operations. To reduce the overall CAPEX cost estimate, it was proposed in FEED to only recomplete four out of the five wells since a maximum of four wells were identified as being required for the PCCS CO_2 injection duty and gave sufficient redundancy.
Modification to GT13	GT13 is a Siemens SGT5-4000F and was installed at Peterhead Power Station in 2000 so is already 15 years old. The OEM offers several standard upgrade options to increase the performance in terms of power output and efficiency of such machines. The decision was taken in FEED to upgrade GT13 since this has a significant positive impact upon the cost effectiveness of the PCCS project – resulting in a lower strike price.
Absorber Location & Aux Boiler Relocation	It was identified during FEED that the CCP absorber location proposed during the pre-FEED phase of the Project would have involved very challenging civil works including stabilising a near vertical 18m high embankment located close to live HP gas facilities. Alternative locations were considered during FEED and the best location identified for the absorber to optimise the overall CCP process layout and minimise duct lengths was the location occupied by the existing auxiliary boiler house. As a result, the decision was taken to relocate and replace the auxiliary boilers to make way for the absorber and Direct Contact Cooler (DCC).
Waste Water Treatment Plant Design Premise	A Waste Water Treatment Plant (WWTP) was always included in the scope for the Onshore Capture Plant but at the beginning of FEED it was not known whether the acid wash effluent could be treated on site, so the Basis for Design assumed that this stream would be trucked off-site for remote disposal. Laboratory-scale testing during FEED indicated that the on-site treatment of the acid wash effluent was feasible but the resulting design for the WWTP facilities ended up far more complex and expensive than had originally been anticipated. A review into cost and operability concluded that in order to de-risk the WWTP design, off-site disposal of the acid wash effluent should be reconsidered. As a result of this review the decision was taken to adopt a simplified Waste Water Treatment Plant design specification for the facilities at Peterhead in conjunction with incineration of the acid wash effluent at a remote location.
HDD	At the start of FEED, Horizontal Directional Drilling (HDD) was the preferred landfall method for the offshore pipeline to minimise environmental impacts. However, an open-cut trench alternative was also considered in parallel since the preferred HDD solution was not proven for the prevailing geological conditions. In

	order to confirm the decision in FEED, a pilot hole was drilled in Q1 2015 to determine the viability of the HDD solution. On the basis of a positive result from the pilot hole, a decision was taken to select HDD as the preferred landfall method for Execute. In addition an option in the Landfall, Pipeline and Subsea EPCI for open cut has been included to maintain a fallback position. Impacts for open cut have been included in both the onshore and offshore environmental statements.
Deferment of Existing Pipeline Inspection by Intelligent Pigging	Verification of the condition of the existing Goldeneye to St Fergus gas pipeline has always been a pre-requisite for the successful implementation of the Peterhead Carbon Capture and Storage Project. Positive data was collected during the hydrocarbon-freeing and pipeline cleaning activities carried out in May 2013, when almost no corrosion products were found in the pipe, but the only way to be sure of the integrity is to carry out a full length survey using a so-called intelligent pig. In order to mitigate risk and achieve maximum cost and schedule certainty, it was originally planned to execute the inspection early in the FEED Phase. The intelligent pigging of the pipeline was estimated to cost some £4mln. Whilst early knowledge of pipeline condition is advantageous, there are a number of benefits from deferring the pigging operation to the Execute Phase. Later execution would allow the inspection of the new 20km spur line from Peterhead at the same time as the existing pipeline. It would mean the survey data reflects the pipeline condition close to start-up and would pick up any further deterioration during the construction phase. These benefits and the intrinsic value of deferring expenditure until after FID were weighed against the primary drivers of early risk mitigation and cost and schedule certainty in the project planning, and the decision was taken to defer the intelligent pigging until the next phase of the project.
Methanol from St Fergus	The pre-FEED design premise was that the CCS project would be wholly supported and operated from Peterhead - requiring a 20 km 4" methanol line to be laid in parallel with the new CO_2 pipeline as well as drilling of a second HDD hole at considerable expense. This solution was reviewed in FEED and as a result of the identified opportunity for a significant CAPEX saving and is also safer, the decision was taken to convert the existing MEG line and storage facilities at St Fergus and convert them to methanol service for PCCS.
W2W Vessel	The Goldeneye Platform accommodation only caters for 12 people – which imposes a severe restriction on any offshore construction schedule. The use of a 'Walk-2-Work' vessel which can be moored close the platform, enables a larger workforce of 24 to be considered (limited by platform lifeboat capacity). This enables a night shift to be utilised (if required), and helps to optimise and reduce the likely overall duration of the offshore construction campaign. A W2W arrangement is considerably cheaper than a jack-up accommodation vessel.

9. Lessons Learned

Shell employs a continuous improvement process which includes mandatory requirements for the retrieval, implementation and capture of learnings on projects. The aim of the process is to ensure that projects do not repeat errors of the past, but identify and repeat successes. Replication and standardization are proven enablers for the general improvement of project cost and schedule performance. The application of lessons learned processes enable the replication of concepts, designs, solutions, ways-of-working and execution strategies that have been proven to work successfully and safely on other projects.

This is of particular importance on First-Of-A-Kind (FOAK) projects such as Peterhead CCS where there are limited previous similar projects to provide relevant learnings. It is useful to identify where it may be appropriate to apply learnings and processes from previous projects, but it is equally important to identify areas where a different approach is preferred and would be more suitable.

It is a requirement that every phase of a Shell project review and decide on opportunities for the replication and standardisation of applied processes. By default, project delivery is pointed towards selection of standard solutions in equipment and design, supply chains and execution methods. Demonstrable justification is required for any deviations from previously developed Shell standard solutions.

In the FEED phase, a number of lessons learned workshops were held with each FEED team. This commenced with the Shell core team at the beginning of FEED. Workshops were held with the individual Onshore, Offshore and Subsea FEED teams during and at the end of delivery of their work stream activities in FEED. A final wrap-up lessons learned review was also held at the end of FEED. These activities generated a number of evaluated lessons from each team. The identified highest impact CCS specific learnings output from this process are presented in Table 9-1 below. More information regarding the lessons learned during FEED can be found in the Key Knowledge Deliverable 11.019 – FEED Lessons Learned Report [28].

Table 9-1: FEED Team Lessons Summary

ID	Key Theme	FEED Team	Discipline	Lesson Type	Lesson Title	Lesson Description & Impact on the project	Proposed Recommendation / Mitigation
1	FOAK	PMO	Project Management	Lesson Learned	FEED management processes needed to evolve from existing O&G and Power sector processes to meet the needs of a FOAK CCS FEED.	Where processes are based on existing practices, it is beneficial to identify FOAK aspects & issues, monitor how they are progressed and then update and incorporate revised processes into the Project's governance procedures.	Sufficient time should be allowed to develop, disseminate and establish processes and procedures on commencing each Project phase of a FOAK project. The time to develop and identify such processes and procedures should not be underestimated.
2	O&G v Power Sector Approach	Shell / PMO	Engineering	Lesson Learned	The Onshore FEED design should be based on appropriate standards and technical principles.	Pre-FEED, PCCS recognised that there may be design and cost benefits from not applying Shell O&G standards to the Onshore FEED since the duty required to support Power Plant operations is less onerous than would typically be applied to an Oil & Gas installation.	The Onshore FEED contractor was only required to apply the process safety aspects of Shell's O&G standards to their FEED design. The learnings from this first FEED study require to be developed further in order for Shell to produce CCS specific standards for use on future projects.
3	FOAK	PMO	Engineering	Lesson Learned	FEED should focus on identifying and resolving FOAK CCS	During FEED priority should be given to resolving as far as possible FOAK CCS issues to reduce the level of uncertainty and de-risk	Consider making additional time / cost contingency allowance in FEED to address potential FOAK CCS issues on top of the usual activities necessary to

ID	Key Theme	FEED Team	Discipline	Lesson Type	Lesson Title	Lesson Description & Impact on the project	Proposed Recommendation / Mitigation
					issues prior to commencing Execute.	the Project scope taken forward into the future Execute phase.	achieve the standard FEED cost and technical outputs. Ensure that FOAK CCS issues which need addressed in FEED are clearly defined and the process to resolution is monitored (and communicated to the Project team) during FEED.
4	FOAK	PMO / Onshore FEED	Project Management	Lesson Learned	Developing new technology and designs for a FOAK CCS project is likely to take longer than expected and result in knock-on delays / impacts to other activities.	The Process Design Package (PDP) issued to the Onshore FEED team from the capture technology provider (Cansolv) and Process Safety extract from Shell's Design & Engineering Standards issued to the PMO were released later in FEED than originally planned. This impacted on progress on related Onshore FEED activities.	An increased likelihood of delivery delays should be expected on FOAK projects due to increased uncertainty in the development of new technology and processes. Such risks could be mitigated by making increased contingency allowance in the scheduling of these activities.
5	FOAK	All FEED Teams	Engineering	Lesson Learned	Increased likelihood that assumptions made on a FOAK project will need to be revised and/or revisited.	Due to the FOAK nature of CCS projects and lack of operational CCS project data, assumptions made at the start of the FEED subsequently had to be revisited which meant that some redesign work was required.	Consider working flexibly and deviating from normal FEED practice to maintain the overall schedule on a FOAK CCS project. For example, detail of the constituent effluent streams was not available until late on in FEED meaning the water treatment design could not finalised without extending the Onshore FEED schedule. Instead, a separate exercise was performed to identify the preferred solution to use as the basis for commencing the Execute phase.
6	Replication	Offshore	Engineering	Best Practice	Good use of historically similar work	The PCCS project made use of knowledge gained and work previously carried out on the Longannet CCS Project. This provided benefits, not least in terms of the Offshore and Subsurface FEED scopes, since it was not necessary for the Shell team to validate or replicate much of the work which had been performed previously on the Longannet CCS project.	Use of experience gained from previous similar projects reduced the required PCCS FEED scope. For example, the Offshore FEED was able to reuse much of the structural integrity and life extension study work performed previously for the Goldeneye platform.

ID	Key Theme	FEED Team	Discipline	Lesson Type	Lesson Title	Lesson Description & Impact on the project	Proposed Recommendation / Mitigation
7	FOAK	Subsea	Process Engineering	Lessons Learned	Process Engineering Philosophy	Changes to the industry approach for handling hydrocarbons is ultimately required for working with CO_2. Until CCS specific engineering processes mature then this will result in increased uncertainty in the produced FEED outputs when compared with performance of FEED on more mature technologies and sectors.	Due to the FOAK nature of the Project, existing Shell FEED processes were not comprehensively rewritten to cover the required CO_2 duty. Collation of learnings generated during the PCCS FEED, and from other future FEED studies across the world can be used as inputs to update Shell's Process Engineering Philosophy and Flow Assurance requirements and ultimately mature to become a CCS specific set of standards for use on N^{th} of a Kind (NOAK) CCS projects.
8	FOAK	Onshore	Design HSE	Lessons Learned	Impact of COMAH legislation requirements on the design.	Evolution of definition of the Project technical requirements during FEED in terms of application of HSE's COMAH legislation in conjunction with a lack of maturity in terms of the application of CO_2 within COMAH impacted upon the delivery schedule. This was further compounded by a change in COMAH regulations in 2015.	Performance of a review at the start of FEED covering the potential project options which needed to be considered during FEED and their COMAH implications would have been beneficial to set expectations and better mitigate impact on the FEED delivery schedule.
9	FOAK	Onshore	Shell/ Cansolv	Lessons Learned	Unresolved Pre-FEED Concept Selection Issues	Going into FEED with too many open items due to novel technology caused additional work and rework in some areas during FEED. For example, delay in FEED activities due to late receipt of biodegradability and absorber lining data.	Concept selection issues should be resolved as early as possible. If some FOAK items remain unresolved, they should be clearly identified and tackled first in the next project phase to maintain the overall delivery schedule.
10	FOAK	Onshore	HSE	Lessons Learned	Waste Water Treatment Plant (WWTP)	Due to the FOAK nature of CCS projects and lack of operational CCS project data, assumptions made at the start of the FEED subsequently had to be revisited which meant that some redesign work was required. One example was the Waste Water Treatment Plant (WWTP) where detail of the	Monitoring of assumptions as well as decisions is important in a FOAK CCS FEED to provide early identification where assumptions are unlikely to be accurate and/or where there is a delay in generating data to confirm the assumptions made. A review of the options for

ID	Key Theme	FEED Team	Discipline	Lesson Type	Lesson Title	Lesson Description & Impact on the project	Proposed Recommendation / Mitigation
						constituent effluent streams was not available until relatively late on in FEED and different from what had been assumed. As a result, it was not possible to finalise the WWTP design during FEED without extending the Onshore FEED schedule.	waste stream disposal was undertaken after completion of the Onshore FEED identifying that it may be cost effective for off-site treatment of selected waste streams.

10. Contracting Supply Chain

10.1. Contract Management Plan

The contract management plan for the Execute project phase outlines the activities to be undertaken in each Tier 1 Sub-Contract (a sub-contract that is contracted by PCCS Ltd) and show which contractor is responsible for each Tier 2 Sub-Contract (a sub-contract that is contracted by the Tier 1 Sub-Contractors).

Each of the separate scope elements will be implemented by the chosen Engineering, Procurement and Construction (EPC) Contractor. Competitive tender for an EPC contracting model has been selected as the preferred execution model with fixed lump sums being tendered by the developer or selected EPC Contractors for the procurement of critical onshore/offshore project requirements. Each of the EPC Contracts will be managed by a Shell Implementation Manager in accordance with the Operating Service Agreement (OSA). The scope of each EPC contract includes provision of project management, detailed engineering, procurement and fabrication elements. Reimbursement is generally proposed on a target cost basis, with a gain share / pain share incentive mechanism taking into account execution efficiency and timely completion with construction and pre-commissioning activities reimbursable on a target cost basis. The structure of the Tier 1 and Tier 2 Sub-Contracts are shown in Figure 10-1, with Tier 1 contracts in orange, and Tier 2 contracts in blue. Note whilst there will be hundreds of Tier 2 Sub-Contracts to the main EPC Tier 1 Contracts, for clarity only the key or material Sub-Contracts with a value >£10 mln are shown in Figure 10-1.

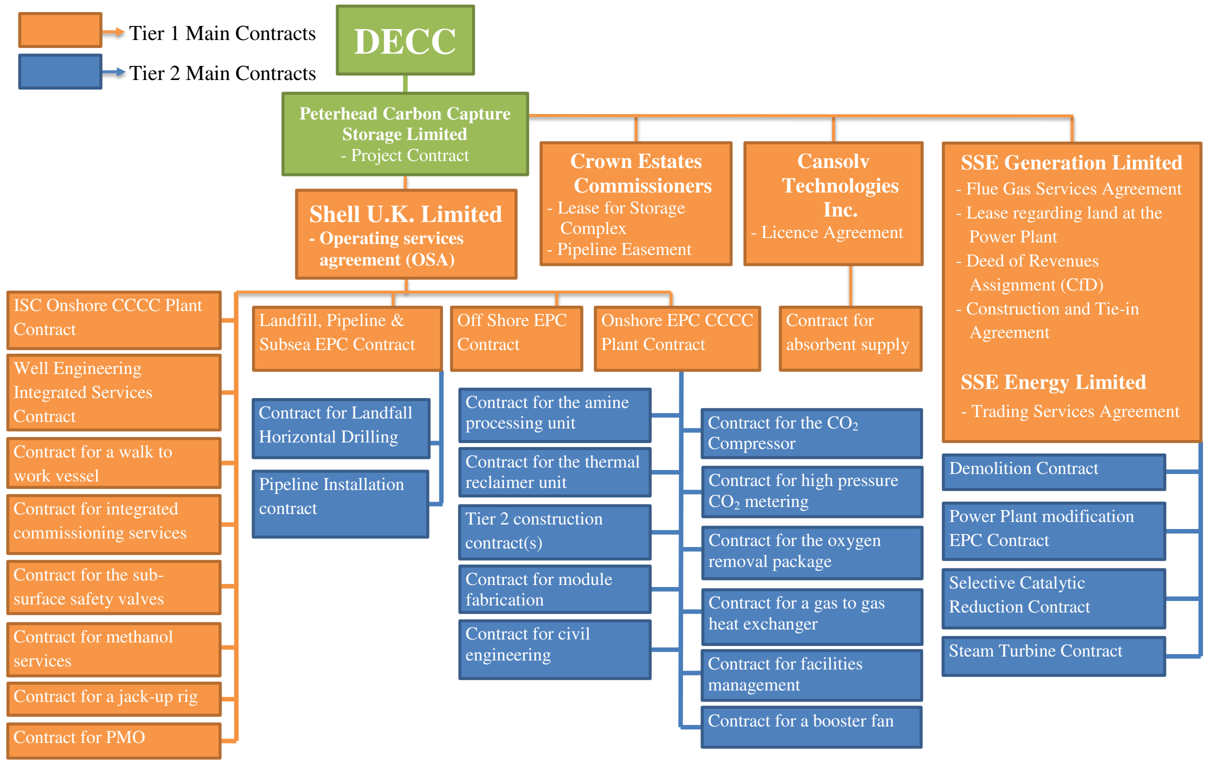


Figure 10-1 : Tier 1 and Tier 2 Sub-Contracts

The structure of the PCCS project is considered to lend itself to tender EPC contracts for the Execute phase as follows:

- Onshore Carbon Capture, Compression & Conditioning plant;
- Landfall, Pipeline and Subsea scope;
- Offshore scope (Goldeneye Platform modifications); and
- Wells and Subsurface Engineering.

Unlike the other EPC Contracts, the Landfall, Pipeline and Subsea EPC contract will be placed on a full lump sum contract.

A separate EPC contract is also proposed for delivery of the Power Plant modification scope in Execute. The rationale for having a separate EPC contract for the CCCC scope and the Power Plant scope is that both are specialised scopes, with a very limited number of EPC contractors that are capable or willing to undertake both.

For this reason, delivery of the Power Plant scope modifications will be the responsibility of SSE, executed in the form of an EPC contract. While the CCCC plant scope will be executed in a separate EPC contract by Shell. The PCCS construction site at the Peterhead Power Station site will be physically segregated from the existing Peterhead power plant operations and also the SSE power plant modification scope.

The Goldeneye platform modification scope will be accomplished by an EPC contractor under the Offshore EPC scope. A key principle of the contract is maximising pre-fabrication and minimising offshore exposure.

Offshore accommodation for the construction workforce will be provided by a Walk-to-Work (W2W) vessel that is fitted with a heave compensated access ramp. A W2W vessel was found to be the most (cost) effective solution during the (FEED) study, as a flotel would be too large for the scope and the platform itself has limited bed space and life-boat capacity that would be impractical to increase.

Wells and Subsurface activities will be managed using multiple contracts.

Modifications are required to the existing Shell-Esso Gas and Liquids (SEGAL) system terminal at St Fergus for the PCCS project. Methanol will be injected into the CO_2 injection wells during well start-up. Methanol is required to prevent hydrate formation and subsequent damage to the reservoir rock upon contact between the injected CO_2 and the reservoir water within the depleted Goldeneye reservoir. Methanol will be provided to the platform from St Fergus, utilising the existing 4-inch glycol pipeline between St Fergus and Goldeneye. At St Fergus, the existing Goldeneye glycol processing facilities will be converted for methanol service.

The St Fergus methanol scope will be implemented by the SEGAL asset owners under their responsibility under a Construction and Tie-in Agreement (CTA). The costs of the methanol scope upgrade at St Fergus will be carried out on a reimbursable basis. The St Fergus works for the required PCCS scope will either be undertaken by the St Fergus operator for the St Fergus Owners under the existing framework contract with the on-site Integrated Services Contractor (ISC) or could alternatively be allocated to a different contractor. As the required scope of work is relatively minor, it can potentially be implemented using existing working practices and resources. If required the SEGAL organisation can access additional project execution capability from Shell. The Peterhead CCS Offshore Implementation Manager will be responsible for the interfaces with other parts of the project.

Further information can be found in the Key Knowledge Deliverable 11.058 – Scope of Work for Execute Contracts [29]. In addition, technical information regarding this project can be found in the Key Knowledge Deliverable 11.003 – Basic Design and Engineering Package [8] and the Key Knowledge Deliverable 11.001 – Basis of Design [12].

10.2. Development of a CCS Services Sector and Supply Chain

The development of a future CCS Services Sector has been demonstrated through support to three main elements: 'Competition', 'Innovation' and 'Skills and Knowledge', governed by a Supplier Management function as illustrated below in Figure 10-2, focusing directly on how the more novel goods and services required by the project will be supported.

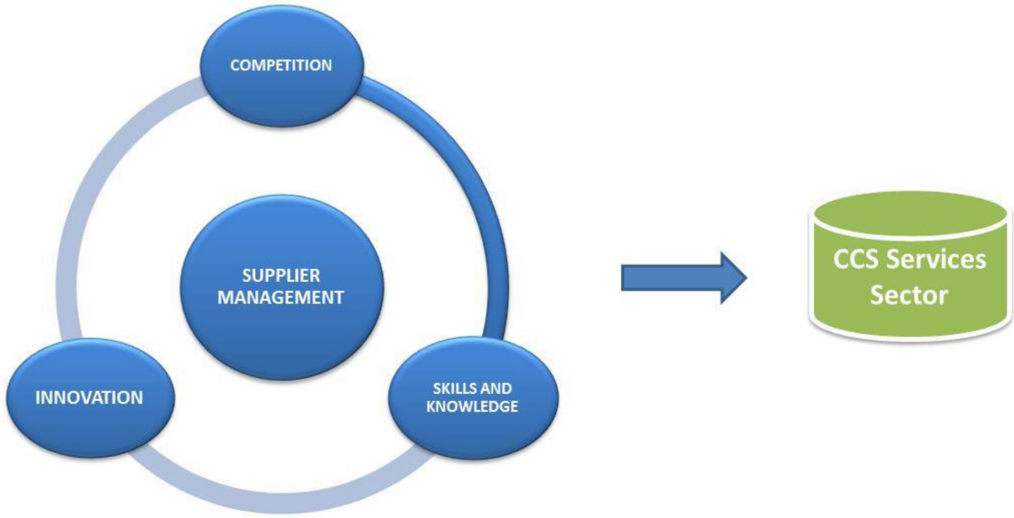


Figure 10-2: CCS Services Sector

Shell's Supplier Management function will provide significant support to the Peterhead CCS project during Execute and as a result will help develop a future CCS Services Sector. Shell has a cost effective, robust, and streamlined process of managing suppliers that ensures structural integrity of potential suppliers which will ultimately ensure stability and sustainability in the supply chain. 'Competition', 'Innovation', and 'Skills and Knowledge' are focus areas given that they are likely to make the most impact for a future CCS Services Sector, where many of the goods and services required are more novel to the supply chain. Competition makes most impact in influencing suppliers in terms of cost, delivery and availability. Innovation also has a part to play in influencing the reduction of cost, as well as the deployment of more efficient equipment and services. Skills and Knowledge make the most contribution to effective deployment, and given the high risk nature of CO_2 projects as well as the novel aspects to CCS, effective Skills and Knowledge are even more significant than usual.

Given the continued decline in oil price over the last year or so, there has been a notable increase in interest from companies traditionally active in the Oil & Gas sector looking at the possibility of becoming involved in the Carbon Capture and Storage sector. This interest was seen to increase as the FEED study drew to a close as companies realised that there was real appetite by Shell to take the Project forward and the CCS business opportunities suddenly became more tangible.

As the North Sea basin becomes more mature, many of the traditional Oil & Gas supply chain companies will be looking to other sectors to diversify. Opportunities such as CCS offer these companies a means to continue to utilise their expertise and knowledge, particularly offshore. In many ways it is a natural evolution of the industry. The collective experience of a supply chain that has been active for 40 years or more should not be underestimated or undervalued as we try to create a CCS sector in the UK.

Through engagement with suppliers and visibility of the goods and services required to deliver a CCS project, a key learning is that the supply chain is already in place to deliver a project like Peterhead CCS Carbon Capture and Storage. In addition to the many goods and services required on the Project, the process of physically constructing the facilities and the learnings gained from that would immediately add value to the companies involved and offer them the opportunity to expand internationally as global development of CCS progresses.

For future projects an important lesson is to build upon the strengths and knowledge that already exists in the supply chain. Innovation is at the core of many of the smaller companies and efficiencies and cost savings would undoubtedly have been gained through the "learning by doing" approach. These companies are very agile in their approach and creative in the solutions that they propose. As the industry strives for cost savings and efficiencies, this is the level where it will happen but only if they get the opportunity to learn by doing.

11. Main Milestone Dates

The schedule for the Execute phase of the PCCS Project has been developed using the latest available information from multiple input sources. For schedule management, the project has been split into five main areas referred to as 'Chain Links'. These are reflected at the highest level within the schedule and comprise of the following scopes:

- **End to End** – this covers the activities that span the full duration of the project and generally aren't specific to any of the other 'Chain Link' categories. These include overall project milestones, Shell owner deliverables, quarterly payment milestones to DECC and other owner's activities etc.;
- **Power Plant** – The power plant is owned and operated by SSE and as such they will be responsible for the execution of the brownfield scope associated with the Peterhead power plant upgrades necessary to support the project;
- **Carbon Capture, Compression and Conditioning Plant** – Shell's Onshore EPC contractor scope covering the design, procurement, fabrication and installation of the plant required to support the capture and compression of the CO_2 from the power station;
- **Offshore Transportation System** – this covers the activities associated with the design, procurement and installation of the pipeline and subsea equipment including the HDD and landfall scopes. The scope for the supply of Methanol from St. Fergus is also covered under this chain link.
- **Storage Facility** – the Goldeneye Topsides Modifications EPC contractor's scope covering the removal and installation of the new topsides facilities required to support CO_2 injection. In addition the Well work over scope and the Subsurface Surveying and Monitoring, Measurement and Verification (MMV) is also covered under this chain link.

A high-level milestone summary has been created to show the key dates for the completion of the Project's major milestones as shown in Table 11-1. This can then be used to help plan, sequence, execute, monitor, analyse and communicate the work and resources necessary to achieve desired deliverables. The presented milestones focus on the design, construction and commissioning activities during Execute after which the project will be handed over by the project delivery team to the operations team. A more detailed breakdown of the Projects milestones and schedule is provided in the Key Knowledge Deliverable 11.029 - Project Schedule [30], while a breakdown of the permits and consents for the project is located in the Key Knowledge Deliverable 11.030 – Permits and Consents Register [27].

Table 11-1: Major Project Milestones

KEY INTERFACES		
Interface	**Start**	**Finish**
Pre-Investment Agreement (SSE Aux. Boiler Scope)	18-Jan-16	
Pre-Investment Agreement (Capture Plant / Wells Early Engineering)	21-Mar-16	
Contract Award – DECC	01-Jul-16	
Site Handover 1 - (CCS / Compression (SSE to Shell) - Enabling	08-Aug-16	

KEY INTERFACES		
Interface	**Start**	**Finish**
Works		
Site Handover 2 – Demolition Area (SSE to Shell)	17-May-17	
Power Plant HAZOP	10-Jan-17	07-Feb-17
Power Plant MC1		03-Apr-19
Carbon Capture and Compression HAZOP	14-Feb-17	21-Mar-17
Carbon Capture Plant – MC1		15-Apr-19
Goldeneye Topsides Modifications - Walk to Work Vessel on Site (Commence Construction)		01-May-18
Goldeneye Topsides Modifications – Construction Complete		01-Oct-18
Well Work over – Rig Mobilisation		10-Oct-18
Well Work over – Complete		27-Mar-19
Commence Subsea Pipeline and associated scope installation	01-May-18	
Complete Subsea Pipeline and associated scope installation		15-Dec-18
Subsea Pipeline and Equipment Installation Complete (including Pre-Comm)		15-Dec-18
Install & Pre-Comm - Pre-Commissioning of Pipeline System (PLR onshore to GE PLR)	23-Nov-18	15-Dec-18
Capture Plant RFSU		07-Nov-19
1st Injection		04-Dec-19
Declare Clean Energy		05-Mar-20

Note that all dates shown are deterministic dates – see section 8 of the Key Knowledge Deliverable 11.029 – Project Schedule [30] for output from the Schedule Risk Analysis.

The deterministic schedule is a network of tasks (representing the whole project) connected to each other with dependencies that describe the work to be performed, that work's duration and the planned start and finished date of the work and the project. Each task has a single planned duration and a predecessor and successor - i.e. the duration of each task is not variable. The longest path through the network is the critical path.

The possibility of variance to any task duration due to uncertain performance or of a risk or opportunity occurring is not incorporated in the deterministic schedule.

12. Costs

12.1. Overview

Estimated cost information for both capital expenditure (CAPEX) and operating expenditure (OPEX) costs for the Execute phase of the Project are summarised below. The CAPEX estimate covers the anticipated costs prior to entering operations – i.e. engineering, procurement, construction and commissioning costs. Costs during the operations period are presented in the OPEX estimate. The cost estimates provided do not include future decommissioning or abandonment costs.

Information on major cost components carrying cost uncertainty is also provided along with summary descriptions of the likely range of risk and reward structures which could be applicable in the CCS supply chain. Further information regarding Costs can be found in the Key Knowledge Deliverable - 11.043 Cost Estimate Report [31].

The presented CAPEX and OPEX estimates have been built up from a base estimate. The complete estimate has been developed from the base estimate by including an allowance for risk and contingency. This creates a P50 base estimate – i.e. the estimate has a 50% probability of over or under-running. The base costs represent approaching 90% of the CAPEX cost estimate and over 95% of the OPEX cost estimate. The contingency applied to the base costs has been calculated through probabilistic risk analysis which incorporated an assessment of all the identified project risks and opportunities. These risks and opportunities included both "CCS specific risks" and "business as usual" risks. The bulk of the risks and opportunities which contributed to the applied cost contingency can be classified as "business as usual" as opposed to "CCS specific". Further information regarding Risks can be found in the Key Knowledge Deliverable – 11.023 Risk Management Plan and Risk Register [25].

12.2. Capital Expenditure (CAPEX) Estimate

The CAPEX and OPEX estimates for the Execute phase of the Peterhead CCS project were developed in accordance with normal Shell practice and appropriate market guidelines such as the Consumer Price Index (CPI) and Rate of Exchange (ROE) to take inflationary effects into account.

In accordance with Shell's normal practice, CAPEX and OPEX estimates were developed in the pre-FEED project phase based upon the concept engineering work carried out at that time.

The PCCS FEED study scope had a duration from March 2014 to December 2015 and consisted of two phases. Within the overall PCCS FEED study scope, an Engineering FEED study was undertaken by Shell and its engineering contractors between March 2014 and February 2015. Once the Engineering FEED study phase was completed, the project team focused on developing the EPC tendering arrangements and undertaking other activities in readiness for the execution phase (Execution Preparation Phase) until the end of November 2015.

The project CAPEX and OPEX estimates were updated mid 2015 based upon the Engineering FEED outputs. The CAPEX estimate was further updated in late 2015 as a result of the increased cost certainty gained through undertaking the EPC tendering process. An updated OPEX estimate was not developed at the end of FEED, since the tendering process for the operations contracts will not take place until after award of the Execute contract.

The CAPEX and OPEX estimates have been built up from a base estimate. The complete estimate has been developed from the base estimate by including an allowance for risk and contingency. This creates a P50 base estimate – i.e. the estimate has a 50% probability of over or under-running.

The CAPEX estimate is expressed in "Money of the Day" (MOD) terms i.e. including inflation and escalation to the date of expenditure. The OPEX estimate has market factor correction applied to take the estimate to a desired Real Terms (RT) P50 date. In the case of PCCS this is also 2015 and therefore no Market Factors were applied.

The CAPEX and OPEX estimates current at the end of the PCCS FEED study are summarised below.

CAPEX costs for the Execute phase of the PCCS project have been based upon the PCCS Project's technical scope and performance requirements detailed in the Basis of Design and Basic Design and Engineering Package Key Knowledge Deliverables – KKDs 11.001 [12] and 11.003 [8] respectively. The Execute phase CAPEX costs have been developed based upon the proposed EPC contract scopes for the provision of detailed design, construction and commissioning works as detailed in the Key Knowledge Deliverable 11.058 – Scope of Work for Execute Contracts [29]. The CAPEX cost estimate covers the entire scope of the Execute phase of the PCCS Project and is reported according to the following elements:

- Venture implementation costs;

- Onshore, covering Peterhead Power Station modification scope of work - including the new steam generator and associated balance of plant; and the Carbon Capture, Compression and Conditioning plant scope of work;
- Landfall, pipelines and subsea scope of work;
- Modifications to the Goldeneye platform and associated logistics scope of work;
- Wells and subsurface scope of work;
- Owner's costs; and,
- Commissioning.

The estimate is based upon cost information available at the end of FEED in December. Although final cost and schedule tender information were not available for all the engineering, procurement and construction (EPC) tenders for the Execute phase at the time of HMG's Statement, it is not expected that the final information would have deviated significantly from the figures presented in this document.

The CAPEX estimate is presented in the table below and subsequent graphics and represents the P50 MOD case. The presented figures include contingency provisions and anticipated foreign exchange (FOREX) related costs.

Table 12-1: Base Case CAPEX Summary

Cost Element	Base Estimate (£ k)
Venture (SPV) Implementation	10,620
Owner's Costs	108,990
Onshore	639,460
Landfall, Pipeline, Subsea	72,580
Goldeneye Modifications	60,690
Wells & Subsurface	88,470
Commissioning (Full CCS Chain)	18,500
FOREX	440
TOTAL	**999,750**

A breakdown for the CAPEX costs is provided in Figure 12-1, Figure 12-2 and Figure 12-3. A more detailed breakdown of the Base CAPEX cost estimate is provided in the Appendix 1 of the Key Knowledge Deliverable 11.043 – Cost Estimate Report [31] based upon the Execute Project phase Work Breakdown Structure (WBS).

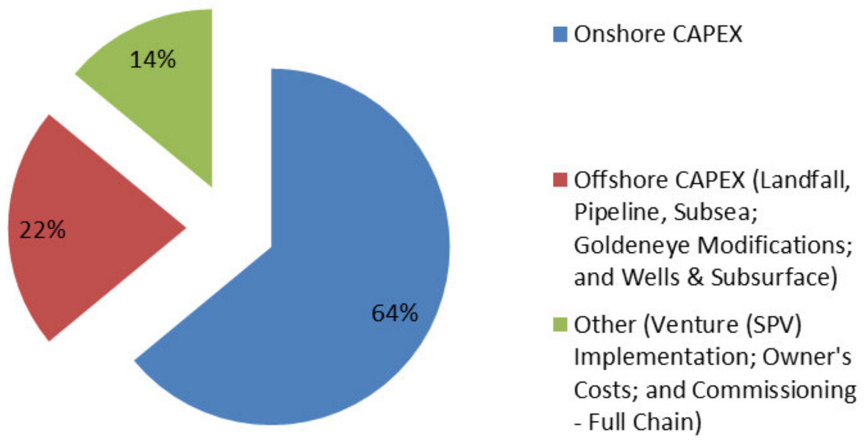


Figure 12-1: PCCS CAPEX Split

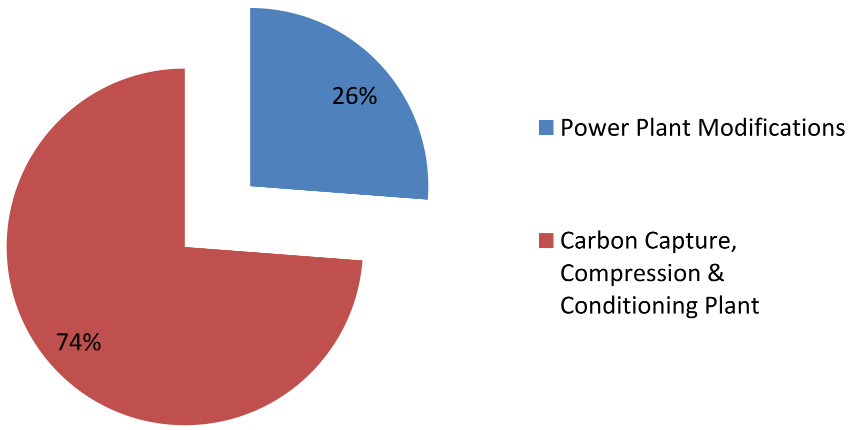


Figure 12-2: PCCS Onshore CAPEX Split

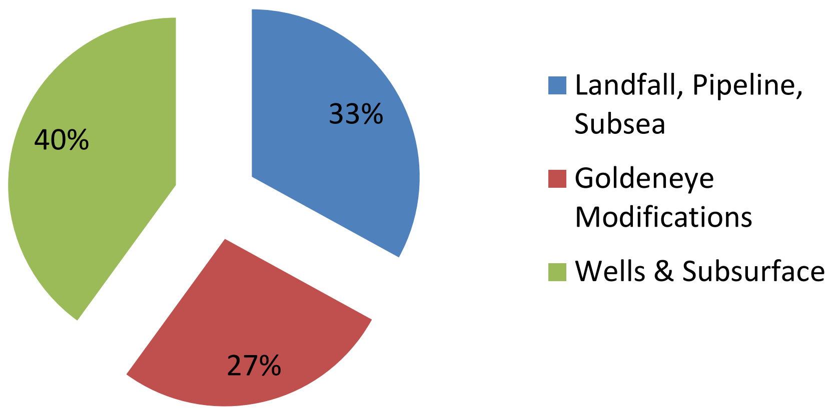


Figure 12-3: PCCS Offshore CAPEX Split

12.3. Operating Expenditure (OPEX) Estimate

The OPEX estimate presented below is based upon information available at the end of FEED in December 2015. Although some commercial agreements had to still be finalised at the time of HMG's Statement, it is not expected that the final information would have deviated significantly from the figures presented in this document. The operational expenditure (OPEX) information should not be used for anything other than presentation of a snap shot of the most up to date estimate as of the end of December 2015.

12.3.1. OPEX Estimation Methodology

In the absence of developed standard practice in the nascent CCS industry, the OPEX estimate has generally been created in line with the Shell practice which reflects the industry standard for OPEX (ISO 15663) [4]. The power plant estimate has been developed by SSE in accordance with standard practice for the power utility sector.

The OPEX model used as the basis of this report is built from:

- The latest project schedule;
- Bottom-up, activity-based modelling techniques;
- Data from the financial model such as:
    - Fuel gas consumption,
    - CO_2 Emissions,
    - Amine consumption,
    - Carbon Capture Conditioning and Compression Parasitic Load;
- Data from 3rd parties for operation of power plant equipment;
- Project Data for waste streams and chemical utilisation;
- Benchmarking studies for manpower.

The OPEX model provides an estimate for the period from 2016 through to 2041 which includes:

- Pre start-up costs for the Goldeneye facility; which are affected by any change in the project schedule;

- Early Measurement Monitoring and Verification activities from 2016 to 2019;
- Injection phase costs for the full chain from 2020 to 2035;
- Post injection phase costs, excluding decommissioning.

12.3.2. OPEX Estimate

The OPEX estimate is presented in the table below and subsequent graphics and represents the Base Estimate, reported in RT2015 (Real Terms 2015). The Base Estimate RT2015 is £3,668.7 million between 2016 and 2041, excluding decommissioning.

Table 12-2: Base Case OPEX Summary

Cost Element	Sub Element	Cost (£ k)
Power Plant OPEX		2,900,500
	Base Plant	366,800
	Fuel Gas	2,336,800
	Carbon Cost	196,900
Carbon Capture, Transport and Storage OPEX		768,200
	Pre Start-Up Costs	16,700
	CCCC Plant Power Consumption	235,100
	CCCC Plant Operations	387,500
	Transport	89,700
	Storage	1,800
	Monitoring (during and post operations)	37,400
TOTAL		3,668,700

The OPEX estimate costs are separately grouped by cost element into Power Plant related OPEX and Carbon Capture, Transport and Storage (CCS) OPEX costs. The OPEX estimate shows that the Power Plant OPEX estimate comprises approximately 80% of the total operating cost, as shown in Figure 12-4 below.

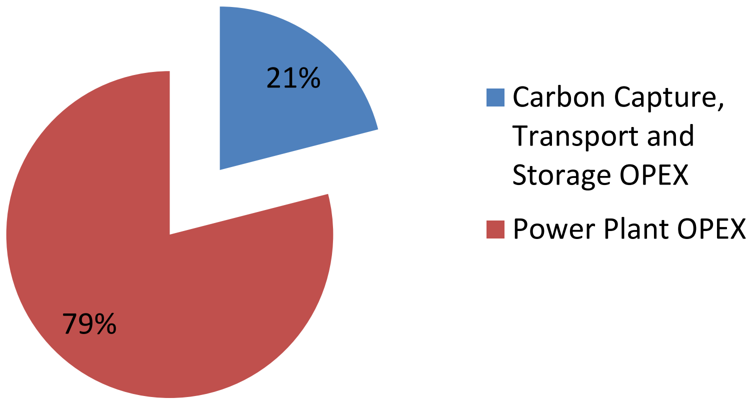


Figure 12-4: PCCS Full Life OPEX Split

The OPEX cost distribution for each year of the Project operating period is shown in Figure 12-5 below.

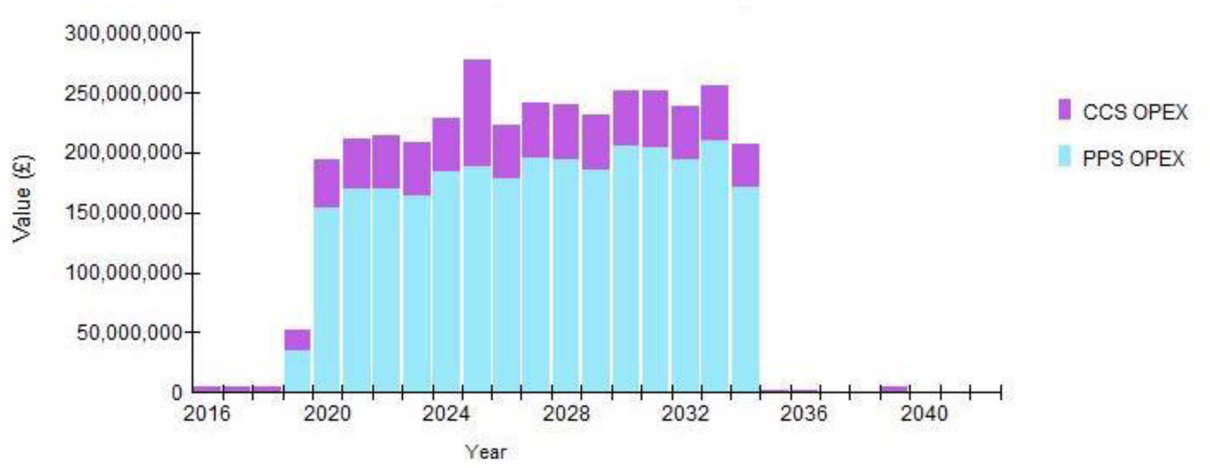


Figure 12-5: Year by Year Base OPEX Estimate

12.4. Power Plant OPEX Costs

The Power Plant OPEX costs for the injection period of 2020 to 2035 account for the majority of the operating costs for the PCCS Project – some 82% of the total OPEX estimate – as shown in Figure 12-6. Within the Power Plant OPEX cost estimate, the fuel gas cost is the dominant cost element - comprising 80% of the Power Plant OPEX cost and 64% of the total PCCS OPEX cost.

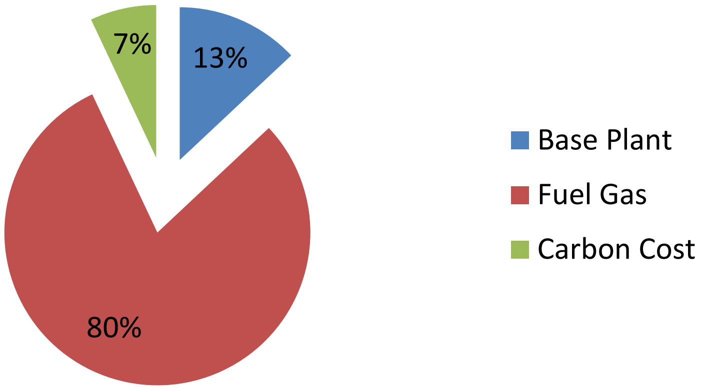


Figure 12-6: Power Plant OPEX Cost Split

The Power Plant OPEX cost is shown in Figure 12-7 spread over the operating period where it can be seen that fuel gas costs are the largest cost within the Power Plant estimate. The OPEX costs are described further in the following report sections.

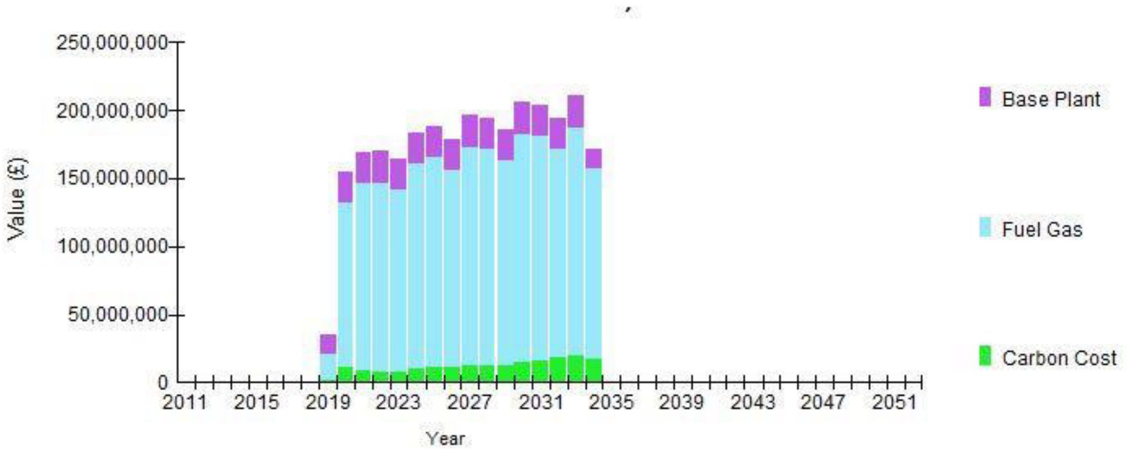


Figure 12-7: Year by Year Power Plant OPEX Estimate

12.4.1. Base Plant Cost

The base plant covers the costs associated with SSE's operation of the Peterhead Power Station aspects attributable to the PCCS Project and have been provided by SSE. As of the end of December 2015, these costs have still to be finalised - particularly the gas turbine's Long Term Service Agreement (LTSA) that will affect the OPEX outturns. These OPEX costs are estimated to comprise 13% of the Power Plant OPEX estimate and 10% of the total PCCS OPEX estimate.

12.4.2. Fuel Gas – Full

Fuel gas costs are incurred as a result of fuel gas used for operating the Power Plant's PCCS-related equipment. This OPEX cost is estimated to comprise 80% of the Power Plant OPEX estimate and 64% of the total PCCS OPEX estimate.

12.4.3. Carbon Cost

The carbon cost includes costs associated with the emission of CO_2 and is calculated by Shell based on modelling the volume and timing of CO_2 emissions and using projected unit Carbon Prices provided by DECC for the period of operation. This OPEX cost is estimated to comprise 7% of the Power Plant OPEX estimate and 5% of the total PCCS OPEX estimate.

12.5. Carbon Capture & Storage (CCS) OPEX Costs

The CCS OPEX estimate for the injection period of 2020 to 2035 accounts for the remainder of the operating costs for the PCCS project – some 18% of the total OPEX estimate. As shown in Figure 12-8, within the CCS OPEX cost estimate the onshore Carbon Capture, Compression and Conditioning (CCCC) Plant costs (summating the CCCC Plant power Consumption and CCCC Plant operating costs) presents the dominant cost element - comprising 81% of the CCS OPEX cost and 15% of the total PCCS OPEX cost.

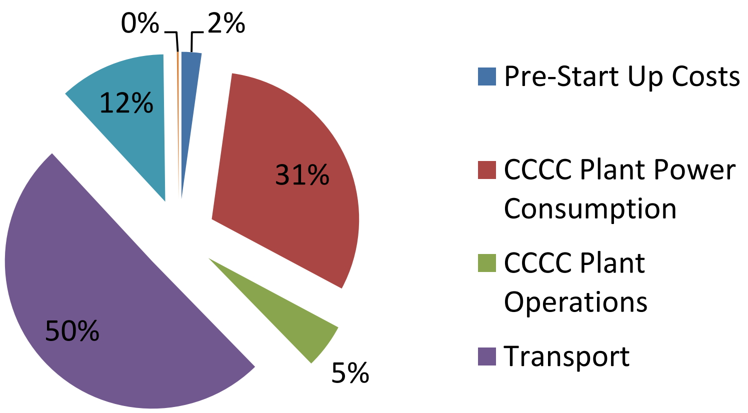


Figure 12-8: CCS OPEX Cost Split

The CCS OPEX cost distribution for each year of the Project operating period is shown in Figure 12-9. Note that allowance for well related activities outside of normal routine maintenance and MMV activities has created a cost spike in year 7 of CO_2 injection. Further information on the proposed injection regime including monitoring plan can be found in the Key Knowledge Deliverable 11.128 – Storage Development Plan [6].

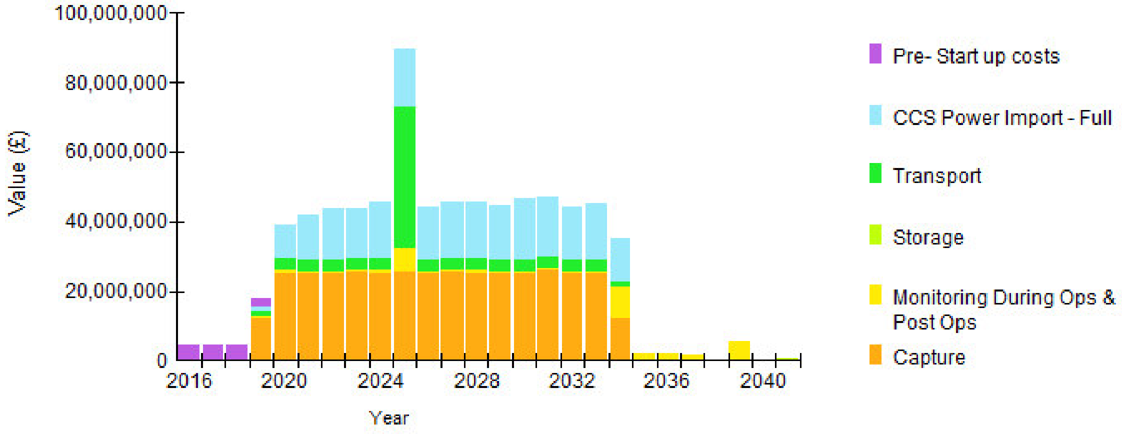


Figure 12-9: Year by Year CCS OPEX Estimate

12.5.1. Pre Start-Up Costs

Pre start-up costs cover the pre Ready For Start Up (RFSU) period of 2016 to 2020 and include:

- Operational Costs: Costs associated with operating the Goldeneye facility including normal operating costs and planned remedial activities; and
- Measurement, Monitoring and Verification (MMV) Costs: Costs associated with MMV activities required prior to CO_2 injection between 2016 and 2018 inclusive.

This OPEX cost is estimated to comprise 2% of the CCS OPEX estimate and <1% of the total PCCS OPEX estimate.

12.5.2. CCS Power Consumption

The CCS Power Consumption costs are associated with the power supply requirement of the Carbon Capture, Compression & Conditioning (CCCC) Plant which is imported from the National Grid during the operating period 2020 to 2035. Power consumption has been based upon the expected CCCC Plant availability as detailed in Section 4.2 in alignment with the imported electrical tariff rate defined by DECC. This OPEX cost is estimated to comprise 31% of the CCS OPEX estimate and 6% of the total PCCS OPEX estimate.

12.5.3. Transport

Transport costs are associated with the subsea pipeline between the onshore CCCC facility and the Offshore installation, Offshore installation and associated wells and the St Fergus supplied Methanol service across the period from 2016 to 2035. This OPEX cost is estimated to comprise 12% of the CCS OPEX estimate and 2% of the total PCCS OPEX estimate.

12.5.3.1. Pipelines

OPEX costs are associated with the ongoing operation and ownership of the subsea pipeline from Goldeneye to Peterhead including pipeline lease fee and periodic maintenance and conditioning monitoring activities including pipelines, risers and subsea structural inspections supplied by the existing SUKEP asset operating the pipeline.

12.5.3.2. Offshore

OPEX costs are associated with the operation and ownership of the Goldeneye facility during the injection period including:

- Offshore insurance fee quotation supplied by the Shell Insurance specialists.
- Well activities outside of normal routine maintenance and MMV activities. This creates a spike in year 7 of injection to allow for 1 contingent tubing replacement. Costs and requirement specified by the Well Engineering team.
- Operation of the installation.

  The operational cost is derived from the current Goldeneye operating cost budget adjusted to include an additional 2 trips to the facility per year (8 in total).

12.5.3.3. St Fergus Methanol supply

Methanol will be supplied to the injection wells from the St Fergus facility via a 4-inch line. The Methanol and associated supply equipment up to the inlet to the 4-inch line are to be owned and operated by the existing owners, SEGAL with a tariff rate provided based on assumed fixed maintenance costs and variable methanol usage.

12.5.4. Storage

The OPEX costs associated with the Storage cost element include:

- Final financial mechanism payment (post transfer obligation);
- Lease Fee (a yearly cost for the lease of the reservoir from the Crown Estate); and
- Storage organisation costs associated with support of the MMV activities across the full life of the project.

This OPEX cost is estimated to comprise <0.3% of the CCS OPEX estimate.

12.5.5. Monitoring during Ops & Post Ops

OPEX costs are associated with the MMV activities undertaken from 2020 to 2041 and include:

- Those MMV activities required for the CO_2 injection period (2020 to 2035);
- Those MMV activities required post CO_2 injection period (2035 to 2041); and
- Monitoring R&D funding;

This OPEX cost is estimated to comprise 5% of the CCS OPEX estimate and 1% of the total PCCS OPEX estimate.

12.5.6. Carbon Capture, Compression & Conditioning (CCCC) Plant Operations

The CCCC Plant OPEX estimate covers costs associated with operating the onshore CCCC Plant are shown in Figure 12-10. This OPEX cost is estimated to comprise 50% of the CCS OPEX estimate and 9% of the total PCCS OPEX estimate.

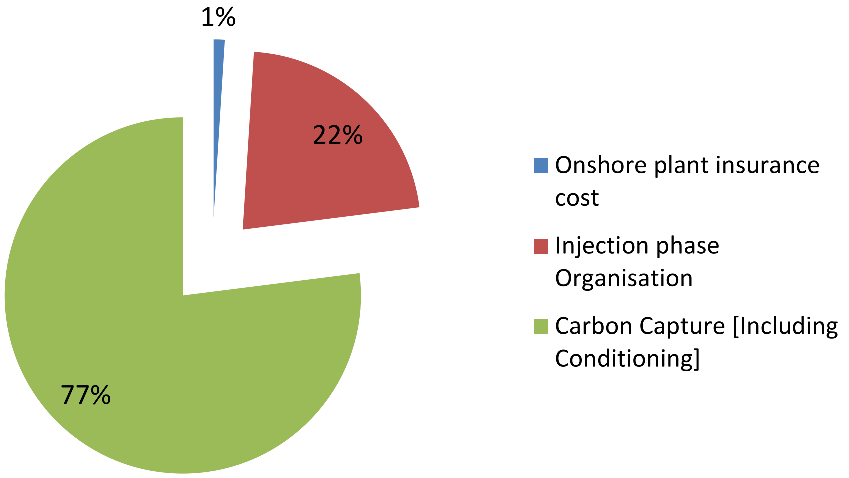


Figure 12-10: Carbon Capture, Compression & Conditioning Plant OPEX Breakdown

12.5.6.1. Onshore plant insurance cost

The Onshore plant insurance cost is a small cost item attributed to the onshore operating phase insurance cost.

12.5.6.2. Injection Phase Organisation

The organisation costs include the OPEX cost for the field team required for the CCCC Plant and provision of the onshore support organisation.

12.5.6.3. Carbon Capture, Compression and Conditioning (CCCC) Plant

A breakdown of the Carbon Capture, Compression and Conditioning Plant cost estimate is shown in Figure 12-11 below.

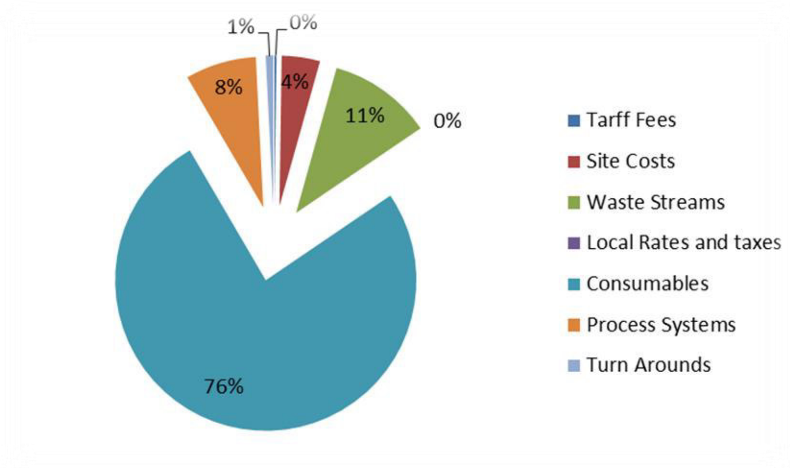


Figure 12-11: CCCC Plant OPEX Estimate

The estimate has been built using a bottom-up approach based on the equipment lists, system structure and equipment OPEX templates for the process equipment and vendor quotation and project process data for chemical usage and waste stream generation. At 76% consumables contributes to the largest costs associated with the chemical usage cost primarily for the consumption and replacement of amine and the handling of waste streams as these are constant costs across the full injection phase not low frequency costs for specific maintenance activities.

12.6. Contractual Risk Allocation

In general, Shell's approach to apportionment of risk and liability is such that risks are allocated to the party best positioned to manage and control them. Shell considers that this provides clarity of risk ownership, and drives the right behaviour, with the aim of reducing the total cost of risk, management and remediation. Such an approach is most likely to result in a Value for Money solution, and in Shell's experience is generally accepted in the EPC Supply Chain.

Therefore Shell has been able to adopt in its EPC Contracts its preferred positions with respect to allocation of hazard type risks given that the Supply Chain is reasonably familiar with such terms and is used to contracting on this basis. Proposed risk allocation for the PCCS Execute phase is summarised in Table 12-3 below.

Table 12-3: Applicable Risks

Risk	Shell (Company)	Contractor
Injury to Company Group Staff	X	
Injury to Contractor Group staff		X
Damage to Company Group property	X	
Damage to Contractor Group Property		X
Pollution from Company Group Assets	X	
Pollution from Contractor Group Assets		X
Company Group Consequential losses	X	
Contractor Group Consequential losses		X
Fines, Penalties punitive Damages levied against Company Group	X	
Fines, Penalties punitive Damages levied against Contractor Group		X
Third Party Liability	Negligence /Fault based	Negligence /Fault based

The risk allocation position between Shell and the EPC Contractor for injury/death to personnel, damage to property and pollution emanating from property damage in what Shell assesses to be either high risk or high value Contracts is based on Knock-for-Knock ("KfK") arrangements. Consequential loss is mutually excluded.

Except for pollution emanating from each party's property, the liability for loss of or damage to property of third parties or injury/death to third parties is allocated based on each party accepting responsibility for its own negligence and/or fault.

The Contractor will take full responsibility for physical loss or physical damage to and pollution emanating from the Permanent Works (which is under the Contractor's care, custody and control) until the point at which the Permanent Works are handed over to Shell.

The Contractor's liability for physical loss or physical damage to the Permanent Works will be capped at an agreed risk retention level. Shell will reimburse the Contractor for the reasonable, substantiated and auditable costs incurred in excess of the risk retention level irrespective of the Contractor Group's fault or negligence. This liability regime is in Shell's experience reasonably standard for EPC Supply chains in the Oil & Gas sector.

It is recommended that future CCS Developers progress their projects with the anticipation that the risk the supply chain is willing to bear, whether it be EPC Contractors, Technology Providers, or even Generators providing services (if they are not themselves the Developer) is limited. It should be understood that full recovery of consequential losses to the Developer in the event that commissioning is late, operations are interrupted or fail altogether is unlikely to be possible given the value of such CCS projects. In the absence of Government support, it is likely that Developers will need to see material reductions in their capital at risk on Nth of a kind (NOAK) projects when compared with FOAK projects in order to take this risk. Additional detail on the contractual risk allocation can be found in Key Knowledge Deliverable 11.142 – Risk allocation across the Project Phase Supply Chain [32].

12.7. Major Cost Components Carrying Cost Uncertainty

The list of major cost components which are carrying the greatest cost uncertainty into the Execute phase of the Project as detailed in Table 12-4.

Table 12-4: Major Costs Components

	Major Costs Component	% of Project Cost	Description of Uncertainty
1	Onshore CCCC Plant Engineering Procurement and Construction (EPC) Contract – Construction Target Cost	17%	A construction Target price Incentive mechanism is proposed for the Construction & commissioning element of the EPC Contract where a pain/gain share mechanism will be agreed with the Contractor
2	Onshore Power station modifications EPC Contract (Balance of Plant including Demolition)	15%	A Target Price Incentive mechanism has been agreed for the PS EPC Contract (Balance of Plant)
3	Hire of Jack-Up Rig – Costs	6%	The jack-up rig will be tendered in 2016 – day-rate costs will be confirmed then. The industry typically tenders rig requirements no more than 2 years ahead of requirements

At the time of HMG's announcement, discussions with the Engineering, Procurement and Construction (EPC) Contractors, SSE and Cansolv were still in process and therefore the final risk and reward allocation within the PCCS Execute contracts was not finalised. However, given their advanced state of development, it is considered that the likely risk and reward allocation in these contracts can be described with sufficient certainty to be instructive to other future CCS developers, notwithstanding the fact that these agreements were not executed. Further information on the proposed Execute phase contract structure can be found in the Key Knowledge Deliverable 11.058 – Scope of Work for Execute Contracts report [29].

The approach to contracting in the Supply Chain is in line with Shell's business as usual contracting approach and is also in line with the industry standard approach. No characteristics unique to the PCCS project have been identified that require Shell to deviate from its usual practice when contracting with its supply chain. Currently there are no known advance payments, reservation fees, down payments or deposits for long lead items, vessel charters and rigs arising from the Supply Chain.

12.8. Potential Risk and Reward Structures

As of the end of October 2015 discussions with the Engineering, Procurement and Construction (EPC) Contractors, SSE and Cansolv are still in process and therefore the final risk and reward allocation has still to be determined. Given their advanced state of development, it is considered that the likely risk and reward allocation in these contracts can be described with sufficient certainty to be instructive to other future CCS Developers, notwithstanding the fact that the agreements have not yet been finalised, more information regarding the risk across the project can be found in the Key Knowledge Deliverable 11.142 – Risk Allocation across Project Supply Chain [32].

SSE's role in the PCCS Project is as a Key-Sub Contractor dedicating the use of its Power Plant equipment to the Project. It is not the Developer, and therefore does not assume the risk or reward profile of a Developer. Given that DECC's desired commercialisation outcome is for private sector electricity companies to take investment decisions to build CCS equipped fossil fuel power stations in the early 2020's without the need for Government Capital Subsidies, the commercial construct employed in this Project, whereby the Developer (Shell) is separate from the Generator (SSE) may or may not be appropriate for 'follow-on' Projects.

Once the Project has been demonstrated technically, for the CCS Commercialisation Outcome to be achieved, it may be necessary for Generators to become CCS Project Developers in future. The CfD construct whereby the Generator is party to the CfD, is entirely consistent with this.

For this Project, the risk allocation between the Developer and SSE as a Key-Subcontractor has trended towards the risk allocation seen in conventional Power Purchase Agreements (PPAs). SSE is well versed in such agreements and has sought to limit its risks to those it fully understands and has control over, and for this reason they are fully shielded from the demonstration risks (i.e. CCS Specific Risks) that Shell and DECC may face. However, certain provisions – for example the 'Grey Period' regime described in more detailed below – are bespoke, in recognition of the novel aspects of the Project.

Future CCS Developers may find that a commercial construct in which the Generator has a commercial arms-length relationship to the Developer is challenging to negotiate. Specifically it may not be appropriate in future to develop CCS projects on the basis of provision of a 'flue gas supply' service by the Generator to the Developer and/or Capture Plant Owner once the capture technology has been demonstrated at scale. In practice, it is anticipated that as the CCS sector matures, the market will seek to move instead to having a 'capture service' being provided by the Capture Plant Owner to the Generator.

12.8.1. Flue Gas Supply (FGS) Agreement

SSE will receive payment via the FGS for providing a range of services, in particular the dedication of facilities including Block 2 (comprising GT13, HRSG13, ST20 and all associated common plant necessary for their operation) for the duration of the PCCS operating period.

Key terms that directly impact the allocation of risk and reward for the Bidder's project include:

- In the event that the CCS Chain is inoperable for a period of 3 months or more at a time, Shell may declare a 'Grey Period' which entitles the Developer certain relief for up to a maximum total period of 15 months over the term of the agreement. In such a Grey Period, SSE's fixed costs (including capital repayments but excluding Market Compensation Charges or MCC) will be paid by Shell. Variable Costs will be paid by SSE. During such a period SSE shall dispatch Block 2 in accordance with power market principles and the profits (net of variable costs) obtained from operating Block 2 will be shared equally (50%/50%) between Shell and SSE.

- The performance of SSE's Dedicated Facilities (Availability) will be monitored on a half-hourly basis and compared against a performance target (accounting for both planned and unplanned outages, average power output and LP steam supply). SSE's fixed costs, MCC and capital payments shall be reduced pro-rata should such availability fall below target. Bonus payments will be payable to SSE should SSE's facilities exceed availability targets, subject to the full chain availability. As of the end of October 2015 this Bonus mechanism is still to be finalised.
- Should the heat rate of GT13 lie above a prescribed threshold then SSE shall be liable for the additional fuel gas required to restore the heat rate to the agreed contractual level. This risk to SSE is capped. SSE is entitled to receive a bonus payment should the actual heat rate lie below the prescribed threshold.

12.8.2. Construction and Tie-In Agreement (CTA)

The Project Contract provides for an Emerging Cost type structure. During the effective term of the CTA, SSE shall receive a fixed proportion of the Capital Grant passed through to the developer at every milestone though to release of the final retention payment by DECC to Shell.

Key terms that directly impact the allocation of risk and reward for the Bidder's project include the following;

- To incentivise both Shell and SSE in respect of timely delivery of their respective construction obligations, each party is liable for payments should actual completion be delayed in respect of a prescribed target completion date. For a SSE delay this will be daily liquidated damages subject to a cap. For Shell, this will require meeting fixed operating and capital funding costs for the gas turbine associated with the delay in the Project in return for [50%] of the net profit from unabated operation of the existing turbine during any such period of delay arising from late completion of the CCS Chain.
- In order to minimise the period between the supply of Flue Gas and full chain commissioning (during which SSE receive full payments), restrictions are put in place that control the delivery of fuel gas before Shell is ready to accept it.
- For the Selective Catalytic Reducer (SCR) equipment, Shell will specify all performance criteria and SSE shall tender for the works on behalf of Shell. SSE is responsible for the installation of the SCR to the required specification. Following commissioning, Shell will take liability for the subsequent performance of the SCR with SSE operating the SCR to Shell's O&M instructions.

13. Conclusion

This document provides a summary of the main project elements and key learning and knowledge generated during the Front End Engineering and Design (FEED) study for the Peterhead CCS project.

An overview of the end-to-end process is included along with high level details of design parameters and the major utilities. Dedicated CCS chain link sections are provided to give a more detailed description of the key engineering aspects for each of the elements throughout the Peterhead Project including:

- Power Plant;
- Carbon Capture, Compression and Conditioning Plant;
- Offshore transportation system;

- Goldeneye Platform;
- Wells; and
- Subsurface reservoir.

These provide links to further information which can be found in other FEED Key Knowledge Deliverables which are included in the reference list. A summary of the project's Health, Safety and Environment (HSE) key findings, top project risks, key decisions and lessons learned from FEED is also provided.

Significant increased cost certainty and risk reduction has been achieved across all aspects of the Project as a result of undertaking the FEED study. As a result, Shell considers that the Project is ready to proceed to the Execute phase. Key FEED Project Performance Parameters developed in FEED are presented which will be taken forwards to the next Execute project phase. A summary of the Contract Management Plan for Execute is included, along with key milestone dates and costs, giving an indication of how it is anticipated that the Project will be taken forward and delivered in Execute.

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[31] KKD 11.043 - Cost Estimate Report.

[32] KKD 11.142 - Risk Allocation across Project Supply Chain.

15. Glossary of Terms

Term	Definition
3D	3 Dimensional
ALARP	As Low As Reasonably Practicable
BAT	Best Available Techniques
BDEP	Basic Design Engineering Package
BGS	British Geological Society
BHT	Bottom Hole Temperature
BOD	Biological Oxygen Demand
BOO	Build-Own-Operate
CAPEX	Capital Expenditure
CCCC	Carbon Capture, Compression and Conditioning
CCGT	Combined Cycle Gas Turbine
CCP	Carbon Capture Plant
CCS	Carbon Capture and Storage
CDT	Conductivity Depth and Temperature
CEMS	Continuous Emissions Monitoring System
CfD	Contract For Difference
CITHP	High closed--in tubing head pressure
CO	Carbon monoxide
CO_2	Carbon dioxide
COMAH	Control of Major Accident Hazards
COSHH	Control of Substances Hazardous to Health
CRH	Cold Reheat
CTA	Construction and Tie-in Agreement
CW	Cooling Water
DCC	Direct Contact Cooler
DECC	Department of Energy and Climate Change
DEP	Design Engineering Practice
DMA	Dimethylamine
DPRIR	Design Phase Risk and Insurance Review
DTS	Distributed temperature sensors
EDU	Energy Development Unit
EIA	Environmental Impact Assessment
EMR	Electricity Market Reform
EOR	Enhanced Oil Recovery
EPC	Engineer, Procure and Construct
ES	Environmental Statement
ESDV	Emergency Shutdown Valve
ETS	Emissions Trading Scheme
EU	European Union
FEED	Front End Engineering Design
FGS	Flue Gas Supply (Agreement)
FOAK	First-Of-A-Kind
FID	Final Investment Decision
FWHP	Flowing WellHead Pressure
FWHT	Flowing WellHead Temperature
GB	Great Britain

Term	Definition
GT	Gas Turbine
H_2	Hydrogen
H_2O	Water
HAZID	Hazard Identification
HAZOP	Hazard and Operability Study
HDD	Horizontal Directional Drill
HDPE	High Density Polyethylene
HF	Hydrogen fluoride
HP	High Pressure
HRA	Habitats Regulations Assessments
HRH	Hot Reheat
HRSG	Heat Recovery Steam Generator
HSE	Health & Safety Executive
HSSE	Health, Safety, Security and Environment
HV	High Voltage
IAQM	Institute of Air Quality Management
IEA	International Energy Agency
IPPC	Integrated Pollution Prevention and Control
ISC	Integrated Serviced Contractor
JT	Joule-Thompson
KfK	Knock-for-Knock
KO	Knock Out
KP	Kilometre Point
LAT	Lowest Astronomical Tide
LHV	Lower Heating Value
LP	Low Pressure
MAH	Major Accident Hazard
MEG	Monoethylene Glycol
MFP	Manifold Temperature
MFS	Minimum Functional Specification
MFT	Manifold Temperature
MMV	Measurement Monitoring and Verification
MP	Medium Pressure
MPL	Minimum Performance Limit
N_2	Nitrogen
NB	Nominal Bore
NGET	National Grid Electricity Transmission
NH_3	Ammonia
NO	Nitric oxide
NOAK	Nth Of A Kind
NO_X	Nitrogen Oxides
NUI	Normally Unmanned Installation
O_2	Oxygen
OBN	Ocean Bottom Nodes
OECD	Organisation for Economic Co-operation and Development
OEM	Original Equipment Manufacturer
OD	Outer Diameter
OGA	Oil and Gas Authority

Term	Definition
OOWC	Original Oil-Water-Contact
OPEX	Operating Expenditure
ORP	Opportunity Realisation Process
OSA	Operating Service Agreement
P&A	Plugged and abandoned
P&ID	Piping and Instrumentation Diagrams
PCC	Process Control Centre
PCCS	Peterhead Carbon Capture and Storage
PDG	Permanent Downhole Gauge
PFD	Process Flow Diagrams
POB	Personnel On Board
PPA	Power Purchase Agreement
PPS	Peterhead Power Station
PPC	Pollution Prevention and Control
PreSDM	Pre-Stack Depth Migration
PSV	Pressure Safety Valves
QA	Quality Assurance
R&D	Research and Development
RAM	Risk Assessment Matrix
RAM	Reliability, Availability and Maintainability
RFSU	Ready For Start Up
RT	Real Terms
S13Cr	Super 13 percent chrome content metallurgy
SAC	Special Areas of Conservation
SAGE	Scottish Area Gas Evacuation
SCCS	Scottish Carbon Capture & Storage
SCFD	Standard Cubic Feet per Decade
SCR	Selective Catalytic Reduction
SEGAL	Shell-Esso Gas and Liquids
SEPA	Scottish Environment Protection Agency
SO	Sulphur monoxide
SO_2	Sulphur dioxide
SPA	Special Protection Area
SS	Stainless steel
SSIV	Subsea Isolation Valve
SSSV	Subsurface Safety Valve
ST	Steam Turbine
ST1	Unit 1 Steam Turbine
t/h	Tonnes per hour
TCM	Technology Centre Mongstad
TDS	Total Dissolved Solids
TPL	Target Performance Level
TSO	Transmission System Operator
TUTU	Topside Umbilical Termination Unit
TVDSS	True Vertical Depth Subsea
TWT	Two-Way Time
UK	United Kingdom
UKCS	United Kingdom Continental Shelf

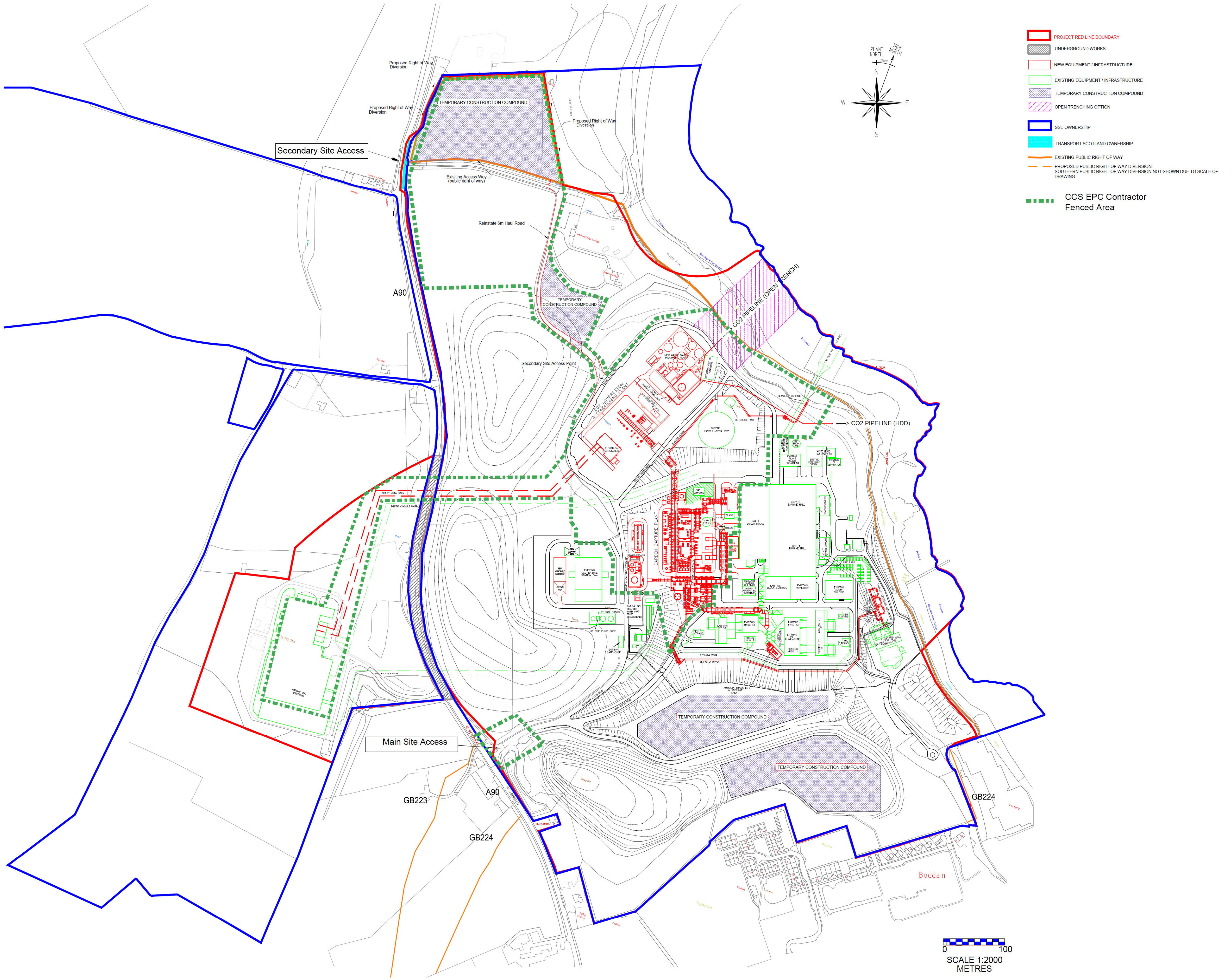
Term	Definition
WHP	Wellhead pressure
WWTP	Waste Water Treatment Plant

16. Glossary of Unit Conversions

Table 9-1: Unit Conversion Table

Function	Unit - Imperial to Metric conversion Factor
Length	1 Foot = 0.3048 metres 1 Inch = 25.4 millimetres
Pressure	1 Bara = 14.5psia
Temperature	ºF=(1.8)(ºC)+32 ºR=(1.8)(K) (absolute scale)
Weight	1 Pound = 0.454 Kilogram

APPENDIX 1. Onshore Plot for Capture Infrastructure


PROJECT RED LINE BOUNDARY
UNDERGROUND WORKS
NEW EQUIPMENT / INFRASTRUCTURE
EXISTING EQUIPMENT / INFRASTRUCTURE
TEMPORARY CONSTRUCTION COMPOUND
OPEN TRENCHING OPTION
SSE OWNERSHIP
TRANSPORT SCOTLAND OWNERSHIP
EXISTING PUBLIC RIGHT OF WAY
PROPOSED PUBLIC RIGHT OF WAY DIVERSION.
SOUTHERN PUBLIC RIGHT OF WAY DIVERSION NOT SHOWN DUE TO SCALE OF DRAWING.
CCS EPC Contractor
Fenced Area
Secondary Site Access
Main Site Access
TEMPORARY CONSTRUCTION COMPOUND
Proposed Right of Way Diversion
Existing Access Way (public right of way)
Reinstate 6m Haul Road
Secondary Site Access Point
CO2 PIPELINE (OPEN TRENCH)
CO2 PIPELINE (HDD)
A90
GB223
GB224
Boddam
0
100
SCALE 1:2000
METRES

APPENDIX 2. Top Ten Risks at the Start of FEED

Risk ID	Risk Title	Risk Description	Risk Status	Planned Finish	Probability Potential risk	Consequence Potential risk Capex Cost	Schedule	Reputation	HSSE	Operability	Probability Residual risk	Consequence Residual risk Capex Cost	Schedule	Reputation	HSSE	Operability
D-0245	Staff experience with CO_2 moving on from project	Cause: Limited in-house staff who are experienced with CO_2 and a protracted process for confirmation if project approval to go ahead. Event: Staff move onto other projects resulting in a loss of CO_2 or CCS expertise or resource requirements are in excess of those planned. Consequence: Loss of experience, delay in project, reduced chance of success.	In Progress	30/12/2014	Very High		High			High	Low		Low			Low
D-0347	Late decisions by SSE may delay the schedule	Cause: Different governance processes/project drivers for Shell and SSE. Event: Key SSE decisions/activities may not be made in line with the overall integrated schedule Consequence: Schedule delay.	In Progress	31/12/2019	Very High		Medium						Low			
D-0299	Revision of CCS Directive in 2015 has onerous consequences	Cause: NGO / public pressure to tighten regulatory framework around CCS operations. Event: CCS Directive contains 2015 review date, and the outcome of review potentially has onerous implications for the project. Consequence: Cost and schedule implications for the project, with the imposition of additional obligations or constraints.	In Progress	01/12/2015	High	High	High			High	Medium	Low	Low			Low
D-0209	Competition complexity causes project delay and budget over-run	Cause: The magnitude/scale and complexity of the overall project (i.e. the long chain from the operating power plant to inject in depleted gas reservoir) and complexity of DECC competitive bid process and potentially changing political landscape over the next 18 months. Event: Do not have full control of cost and schedule due to DECC driven processes and timeline. Consequence: Project delay and budget overrun.	In Progress	30/12/2019	High	High	High	Medium			Medium	Medium	Medium	Medium		
D-0327	Cost escalation due to lack of competition and single source negotiation	Cause: Possible EPC Contractors have indicated that if the FEED Contractor is also allowed to bid for the EPC for the CCCC plant then the tender exercise will not be a level playing field. Event: Other contractors decline to bid. Consequence: Cost escalation due to lack of competition and single source negotiation.	In Progress	30/11/2015	High	Medium					Low	Very Low				
D-0220	Extended Post-Closeout Monitoring Requested by Regulator	Cause: Due to first of a kind nature of activity and uncertainty over CO_2 monitoring, regulator requests additional post closeout monitoring. Event: Monitoring is determined to require the platform to be left in place post cessation of injection. Consequence: Increased Opex and greater safety and environmental monitoring requirements.	Accepted	01/07/2015	Medium	High	High			High	Very Low	Medium	Medium			Medium
D-0211	Difficulties in agreeing CfD while EMR is ongoing.	Cause: The Electricity Market Reform (EMR) is currently ongoing; therefore there is a lack of clarity around the Project Contract/CfD structure. Event: Cannot enter into effective negotiations with DECC on the structure and terms of the contract/CfD. Consequence: Delay in signing project contract erodes shareholder value.	In Progress	07/12/2015	Medium		High			Very High	Very Low		Low			Very Low

Risk ID	Risk Title	Risk Description	Risk Status	Planned Finish	Probability Potential risk	Consequence Potential risk Capex Cost	Schedule	Reputation	HSSE	Operability	Probability Residual risk	Consequence Residual risk Capex Cost	Schedule	Reputation	HSSE	Operability
D-0223	Failure of DECC to obtain State Aid clearance for CfD Contract	Cause: CfD is considered to be a State Aid subsidy. Event: Legal challenge may be made against the provision of ALL CfD aid/funding from the state. Consequence: Onerous conditions lead to risk of project cancellation, or prolonged EU review process leads to excessive delay which affects Shell Bid.	In Progress	30/11/2015	Medium		High			Very High	Very Low		Very Low			Very Low
D-0272	Horizontal Directional Drilling (HDD) not possible for pipeline	Cause: Unfavourable geological ground conditions mean HDD proves difficult or impossible. Event: Pipeline hole not stable enough for preferred approach of HDD. Consequence: Have to look at alternative construction i.e. Open cut, meaning offshore concept needs to be re-visited resulting in cost and schedule impact.	Accepted	30/12/2017	Medium	Very High	High	High			Low	Medium	Low	Very Low		
D-0309	Higher levels of solvent degradation than model based design	Cause: Degradation/ make-up rates can be calculated but not proven (no capture plant at this scale). Event: degradation and make-up rates could be higher than anticipated. Consequence: OPEX increase from increased solvent, also increases the waste treatment requirements.	Accepted	06/05/2019	Medium	Very High		Medium		Medium	Very Low	Low		Low		Low

APPENDIX 3. Top Ten Risks at the End of FEED

Risk ID	Risk Title	Risk Description	Risk Status	Planned risk closure date	Current severity/ Due Capex Cost	Schedule	Operability	Reputation	People-HSE	Assets-HSE	Environment-HSE	Reputation-HSE	Mitigation Action ID	Mitigation Action Title	Mitigation Action Status	Mitigation Action Due Date	After Action severity Capex Cost	Schedule	Operability	Reputation	People-HSE	Assets-HSE	Environment-HSE	Reputation-HSE
D-0209	Competition complexity causes project delay and budget over-run	Cause: The magnitude/scale and complexity of the overall project (i.e. the long chain from the operating power plant to inject in depleted gas reservoir) and complexity of DECC competitive bid process and potentially changing political landscape. Event: Do not have full control of cost and schedule due to DECC driven processes and timeline. Consequence: Project delay and budget overrun, leading to stakeholder concerns over deliverability of project	Taken	30/12/2019	C [H/H]	SCH [H/H]		REP [H/M]					A-0193	Shell/SSE Steering Group meetings	Closed	30/12/2019	C [M/M]	SCH [M/M]	OP [M/L]	REP [M/M]				
													A-0435	Actively engage UK Gas Advocacy network	Closed	26/03/2019								
D-0303	DECC and/or EU Commission impose onerous requirements as part of Permit award	Cause: Risk tolerance of regulators for early demonstration projects leads to the imposition of onerous conditions for awarding the storage permit. These could take the form of: onerous site closure obligations, issues with proposed transfer of responsibility, onerous monitoring regime and financial responsibility requirements. Event: Storage permit is granted with onerous conditions attached. Consequence: Potential requirement for significant level of additional monitoring, financial security and acceptance of more liability impacts costs and project schedule.	Active	31/03/2016	C [H/H]	SCH [H/M]	OP [H/H]						A-0316	Early and detailed engagement with regulators	In Progress	30/12/2015	C [M/L]	SCH [M/L]	OP [M/L]					
													A-0317	External Review of Permit and modelling of storage	Closed	31/08/2014								
D-0286	Surface release of CO_2 and reservoir fluids at well during workover/well intervention activities	Cause: Reservoir at high pressure full of CO_2 and some condensate + gas Event: High expansibility of CO_2 and operational issue during well operations (workover, well intervention activities) might lead to release scenario. This can be due to accidental damage to the tree/wellhead, or non-adherence to operational procedures during a CO_2 well workover Consequence: Well/Platform unavailable for injection, leading to loss of revenues	Active	30/12/2031	C [M/VH]	SCH [M/VH]	OP [M/VH]	REP [M/VH]	P (HSE) [C/5]				A-0303	CO_2 workover procedures rig / wireline operability under CO_2 conditions	In Progress	31/12/2015	C [VL/H]	SCH [VL/VH]	OP [VL/VH]	REP [VL/VH]	P (HSE) [A/3]			
													A-0361	Investigate how to qualify rigs for CO_2 intervention	In Progress	30/09/2017								
													A-0712	Prepare response to cover event of Hydrocarbons + coming to surface during any CO_2 leak	Proposed	24/01/2019								
													A-0724	Run workshop with Denbury and/or Occidental in USA	Closed	30/08/2015								
													A-0725	Recovery strategy - Blow Out Preventer on the beach etc.	Active	31/12/2015								
D-0309	Higher levels of solvent degradation than model based design	Cause: Degradation/ make-up rates can be calculated but not proven (no capture plant at this scale). Event: degradation and make-up rates could be higher than anticipated Consequence: OPEX increase from increased solvent, also increases the waste treatment requirements	Active	06/05/2019	C [M/VH]		OP [M/M]	REP [M/M]					A-0395	Consider additional testing of solvent	Closed	31/03/2015	C [VL/L]		OP [VL/L]	REP [VL/L]				
													A-0456	Relay results of testing back to project	Active	31/12/2015								

Risk ID	Risk Title	Risk Description	Risk Status	Planned risk closure date	Current severity/ Due Capex Cost	Schedule	Operability	Reputation	People-HSE	Assets-HSE	Environment-HSE	Reputation-HSE	Mitigation Action ID	Mitigation Action Title	Mitigation Action Status	Mitigation Action Due Date	After Action severity Capex Cost	Schedule	Operability	Reputation	People-HSE	Assets-HSE	Environment-HSE	Reputation-HSE
D-0573	Unexpected increase in corrosion in wells owing to starting and stopping and the formation water + CO_2	Cause: Unexpected combination of ions in the water caused by CO_2 interactions and the possible occasional presence of oxygen could react with the metal and cause corrosion and failure of the well components. Event: Every time a well is turned off, there is a possibility that water will flow back into the well. Consequence: Increased corrosion in well, well could be permanently shut-in leading to requirement for new well to be drilled (cost/schedule impact) Cause: Unexpected combination of ions in the water caused by CO_2 interactions and the possible occasional presence of oxygen could react with the metal and cause corrosion and failure of the well components. Event: Every time a well is turned off, there is a possibility that water will flow back into the well. Consequence: Increased corrosion in well, well could be permanently shut-in leading to requirement for new well to be drilled (cost/schedule impact)	Active	31/08/2030	C [M/VH] C [M/VH]	SCH [M/VH]							A-0632	Selection of well components to minimise corrosion risk, performing corrosion experiments, sparing strategy	Closed	31/08/2015	C [L/L]	SCH [L/L]						
													A-0633	Well Cat modelling	In Progress	30/12/2016								
													A-0634	Integrity logging during workover	In Progress	01/03/2020								
													A-0635	Reservoir section abandonment	In Progress	01/03/2020								
													A-0636	Spare well available (i.e. don't abandon 5th well)	In Progress	12/12/2015								
													A-0637	Book a rig slot when we are doing start up -to prevent us having to remobilise rig to drill new wells / execute corrective measures (e.g. tubing leak)	Closed									
													A-0638	Have rig on site while starting up (delay drilling to 2019)	Closed									
D-0223	Failure or significant delay by DECC to obtain State Aid clearance for Project contracts being the Project Contract with DECCand the CfD Contract with LCCCL	Cause: CfD is considered to be a State Aid subsidy (also applies to the capital grant in the Project Contract with DECC) Event: Legal challenge may be made against the provision of all aid/funding from the state Consequence: Delay impacting Shell bid, or risk of project cancellation if State Aid case not approved.	Active	30/06/2016		SCH [M/H]	OP [M/VH]						A-0437	Discuss with DECC the implications that other State Aid cases will have on our application	Closed	30/05/2014		SCH [VL/VL]	OP [VL/VL]					
													A-0484	Ongoing dialogue to support HMG CCS State Aid application(s)	In Progress	30/06/2016								
D-0250	Emission of nitrosamines and other degradation products	Cause: Emission & other degradation products from the onshore CCP Event: Potential health impacts are not effectively communicated via public consultation (or fully understood by affected stakeholders), or Shell/3rd party emissions modelling is unacceptable to regulators. Consequence: Impact on design causing cost increase & schedule delay from additional regulatory requirements, stakeholder reputation damage & possible litigation), HSSE impacts	Active	31/12/2015	C [M/M]	SCH [M/M]	OP [M/M]	REP [M/H]	P (HSE) [C/3]				A-0250	Undertake Health Risk Assessment	Closed	01/09/2013	C [VL/VL]	SCH [VL/VL]	OP [VL/L]	REP [VL/L]	P (HSE) [A/1]			
													A-0251	Investigate inclusion of De-NO_X system to minimise the risk of nitrosamine formation	Closed									
													A-0252	Perform nitrosamines and nitramines formation emission dispersion modelling/ Environmental chemistry	Closed	31/03/2015								
													A-0470	Develop clear messaging on nitrosamines and share this with the local community	Closed	31/12/2015								

Risk ID	Risk Title	Risk Description	Risk Status	Planned risk closure date	Current severity/ Due Capex Cost	Schedule	Operability	Reputation	People-HSE	Assets-HSE	Environment-HSE	Reputation-HSE	Mitigation Action ID	Mitigation Action Title	Mitigation Action Status	Mitigation Action Due Date	After Action severity Capex Cost	Schedule	Operability	Reputation	People-HSE	Assets-HSE	Environment-HSE	Reputation-HSE
														through public consultation events'										
													A-0502	Secure Shell Occupational Health resource for amine toxicology expertise & prepare report in support of solvent use.	Closed	31/12/2014								
													A-0662	Investigation of nitrosamine risk	Closed	31/05/2015								
D-0614	Performance of WWTP based on FEED design	Cause: Regulator requirement for shared waste water treatment facility to be used by both SSE and Shell at the power station. Event: Ondeo FEED for shared WWTP for both PPS & CCP proposes a larger design than originally thought, and raised concerns over operability, discharge limits as well as construction cost/schedule. Consequence: Higher CAPEX cost & time to construct proposed WWTP, also potential impact on operability due to complex design	Active	31/12/2016	C [M/H]	SCH [M/VL]	OP [M/H]	REP [M/H]					A-0726	Seek assistance from water treatment experts including feedback on EPC tender proposals	In Progress	31/10/2015	C [L/L]	SCH [L/VL]	OP [L/L]	REP [L/L]				
													A-0730	Identify offsite disposal route & associated costs for acid wash effluent	In Progress	31/10/2015								
D-0220	Extended Post-Closeout Monitoring Requested by Regulator	Cause: Due to first of a kind nature of activity and uncertainty over CO_2 monitoring, regulator requests additional post closeout monitoring. Event: Monitoring is determined to require the platform to be left in place post cessation of injection. Consequence: Increased OPEX and greater safety and environmental monitoring requirements	Active	31/01/2016			OP [M/H]						A-0212	Address with DECC in the permit discussions	In Progress	31/12/2015			OP [VL/ M]					
													A-0392	Employ enhanced monitoring	Closed	30/12/2014								
D-0464	Unavailable SSSV due to low temp requirements	Cause: Only 4 SSSVs are required for a very specific design specification, and concerns over whether this may be economically attractive or viable for valve suppliers Event: Vendors unwilling to provide bids for work, or delay in securing contract/valves Consequence: Delay in achieving first injection date	Active	31/03/2016		SCH [H/M]							A-0705	Vendor feasibility study to develop a SSSV valve suitable for low temperatures	Active	31/03/2016		SCH [VL/V L]						