Peterhead CCS Project

Doc Title: Basic Design and Engineering Package

Doc No. **PCCS-00-PTD-AA-7704-00002**
Date of issue: **28/03/2016**
Revision: **K05**
DECC Ref No: **11.003**
Knowledge Cat: **KKD – Technical**

KEYWORDS
Peterhead, Goldeneye, CO_2, Basis of Design, CCS, Design Requirements.

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

IMPORTANT NOTICE

Information provided further to UK CCS Commercialisation Programme (the **Competition**)

The information set out herein (the **Information**) has been prepared by Shell U.K. Limited and its sub-contractors (the **Consortium**) solely for the Department for Energy and Climate Change in connection with the Competition. The Information does not amount to advice on CCS technology or any CCS engineering, commercial, financial, regulatory, legal or other solutions on which any reliance should be placed. Accordingly, no member of the Consortium makes (and the UK Government does not make) any representation, warranty or undertaking, express or implied as to the accuracy, adequacy or completeness of any of the Information and no reliance may be placed on the Information. In so far as permitted by law, no member of the Consortium or any company in the same group as any member of the Consortium or their respective officers, employees or agents accepts (and the UK Government does not accept) any responsibility or liability of any kind, whether for negligence or any other reason, for any damage or loss arising from any use of or any reliance placed on the Information or any subsequent communication of the Information. Each person to whom the Information is made available must make their own independent assessment of the Information after making such investigation and taking professional technical, engineering, commercial, regulatory, financial, legal or other advice, as they deem necessary.

Table of Contents

Table of Figures

List of Tables

Executive Summary

The purpose of the document is to provide a high level technology and engineering scope description for the Peterhead Carbon Capture and Storage (CCS) project. A brief description of the parties involved and their respective roles in the project is provided to help give an understanding of the division of the plant for operational and maintenance activities.

An overall summary of the Peterhead CCS project, including locations of the main Carbon Capture and Storage (CCS) elements and a description of the existing facilities which will be re-used or modified for use in the Project, is contained within the document.

An overview of the end-to-end process is included along with high level details of the interfaces and their parameters between the main process elements at the intended normal operating condition. 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. These provide links to further information which can be found in the documents included in the reference list.

A discussion of the operation and maintenance regime which will be put in place during the design life of the project is also included in the document, in particular where this is relevant to, and influences the design of the Project.

Table ES-1 below shows a brief overview of the main system parameters of the Peterhead CCS project chain quoted under normal operating conditions. It was the Project's intention that these parameters would define the performance of the full PCCS chain and provide the basis of a Minimum Functional Specification for the Execute phase of the project.

Table ES-1: Summary of Plant Performance

Parameter	Units	Target Level	Notes
Gross electrical power	MWe	397.4	Total gross electrical power for PCCS is the sum of the GT13 gas turbine and ST20 steam turbine generator's rated output.
Net exported electrical power	MWe	383.5	Net PCCS exported power is the electrical power exported across the fiscal meter at the 275kV substation. This equates to the PCCS gross electrical power less the unitised PCCS auxiliary demand (supplied directly from the generating units).
Electrical Parasitic Load			
Power Plant Block 2	MWe	6	This is the electrical parasitic load attributable to the PCCS generating plant when in operation at rated output. This figure does not include demand directly supplied from the gas turbine or steam turbine units.
Carbon Capture Plant	MWe	16.5	Demand for design operating case.
Compression and Conditioning	MWe	18	Demand for design operating case.
Platform	MWe	0.1	Demand for design operating case.

Parameter	Units	Target Level	Notes
Low pressure steam flow to Carbon Capture Plant	t/h	181	At design operating case.
Medium pressure steam flow to Carbon Capture Plant	t/h	4.8	At design operating case.
Flue gas processed by Carbon Capture Plant	t/h	2,466	GT13 flue gas flow to Carbon Capture Plant at rated output.
Mass of CO_2 in flue gas processed	t/h	145.5	At design operating case.
Mass of CO_2 transported, $M_{CO2TRANS}$	t/h	128.3	CO_2 flow from compressor plant into the offshore transportation system.

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. A detailed package of engineering documents was produced during the Engineering FEED study which is included in the Appendices.

The technical concepts of the PCCS design were further developed in some areas after completion of the Engineering FEED deliverables at the end of February 2015 – for example as a result of feedback from the EPC tendering process for the Execute phase. The detailed engineering FEED deliverables were not updated to reflect these concepts during the Execution Preparation Phase of FEED. The Engineering FEED study deliverables which do not reflect the final FEED design are clearly identified in the contents pages detailing the Appendices to this document.

As described in the Scope of Work for Execute Contracts – KKD 11.058 [1], after commencement of the Execute phase the intention was that the preferred EPC contractors would perform Detailed Design based on the PCCS technical design, as finalised at the end of the FEED, prior to commencing construction activities. Final technical deliverables which would have superseded the Engineering FEED study deliverables would have been produced at the conclusion of that Detailed Design exercise.

An overview of the entire PCCS FEED study work can be obtained in the FEED Summary Report - KKD 11.133 [2]. The Basis of Design – KKD 11.001 [3] has been updated to reflect any design decisions taken up to December 2015 and reflects the Project's technical status at the end of the PCCS FEED.

Detailed technical information on the technical aspects of the PCCS FEED study phase outcomes can be found in this document. The BDEP expands on the technical information provided in the Basis for Design and includes technical design documentation such as process flow diagrams, piping & instrumentation diagrams, heat and mass balance data and electrical single line diagrams as developed by the Engineering FEED study. Key decisions which were made during FEED, including decisions related to the technical scope of work, are summarised in the FEED Decision Register – KKD 11.020 [4].

Other aspects of the technical FEED study which are described in the suite of PCCS FEED Study Key Knowledge Deliverables include:

- the Surveillance, Metering, Allocation Strategy and Design Package – KKD 11.077 [5] which contains further information on the CfD and EU ETS metering;
- The Technology Maturation Plan – KKD 11.064 [6], which describes the development of identified key technology aspects which were identified, investigated and/or progressed during FEED;
- The Risk Management Plan and Risk Register – KKD 11.023 [7], which described the top project risks, overall risk profile and risk management plan at the end of the FEED study including technical risks; and
- The FEED Lessons Learned Report – KKD 11.019 [8], which describes the lessons learned process undertaken during FEED and presents key learnings identified including CCS specific technical learnings.

1. Introduction

An End-to-End CCS Chain Basis of Design document [3] was developed during the pre-FEED phase of the Peterhead Carbon Capture and Storage (PCCS) project. This was based on the best available data at the time and summarised the project design data which was utilised by the FEED contractors at the commencement of the FEED study.

This document has been developed from the pre-FEED End-to-End CCS Chain Basis of Design [3]. It defines indicative key project design data and criteria, and the process conditions at the principal interfaces between the various elements of the CCS chain. Consequently it provides potential developers with the basic design of a full-scale CCS system. This document incorporates learnings and lessons learned during FEED and includes changes to data that were identified as design requirements during FEED. It does not provide a detailed basis of design for individual plant or parts of the CCS chain.

After this introduction section, an overview of the PCCS project is provided in Section 2. Design criteria and site and engineering data applied in the developed FEED design are described in Sections 3 and 4 respectively. Sections 5 and 6 describe the significant parameters of the key process and utility streams on the PCCS project. Note that due to differing naming conventions between the power and oil & gas sectors, Process Flow Diagrams (PFDs) and P&IDs produced for the power plant scope are equivalent in content to the Process Flow Schemes and Process and Utility Engineering Flow Schemes respectively for the CCCC and offshore scope elements.

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 design dossiers listed in the Appendices of this document are not always consistent with the latest information in the main body of this document. The areas of continued design development in the Execution Preparation Phase will be addressed during Detailed Design in the Execute phase of the Project and the design dossiers that are affected are annotated in their respective Appendix contents listing. 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;
- Contract for Difference (CfD) and Emissions Trading Scheme (ETS) specific metering.

The waste water treatment plant design proposed at the end of FEED is described in Section 6.8. Further information is also provided in the FEED Decision Register – KKD 11.020 [4].

The Engineering FEED was not based upon implementation of the gas turbine upgrades and therefore the technical information included in APPENDIX 2 does not reflect the position at the end of FEED. Further information can be found in the FEED Decision Register – KKD 11.020 [4]. 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 Technology Maturation Plan – KKD 11.064 [4]. Information on the CfD and EU ETS metering requirements can be found in the Surveillance, Metering, Allocation Strategy and Design Package – KKD 11.077 [5].

As well as the novel aspects of designing a First-of-a-Kind post-combustion capture CCS project for a gas-fired power plant, the design has also been influenced by local regulatory aspects, including EU ETS and the UK Government's Contract for Difference (CfD) mechanism which are still in the process of being matured. Further development in these regulatory requirements, or the interpretation thereof, may impact on the proposed design at the next phase.

2. Project Overview

2.1. Overall Project Description

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

The Goldeneye gas-condensate production facility has already ceased production. Under the PCCS Project, the facility will be modified to allow the injection of dense phase CO_2 captured from GT-13 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, 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 directly offshore to the wellhead platform via a new offshore pipeline which will tie-in subsea to the existing Goldeneye pipeline.

Once at the Goldeneye 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 2-3.

A summary of the full chain CCS process, as shown in Figure 2-1, is described in the following sections.

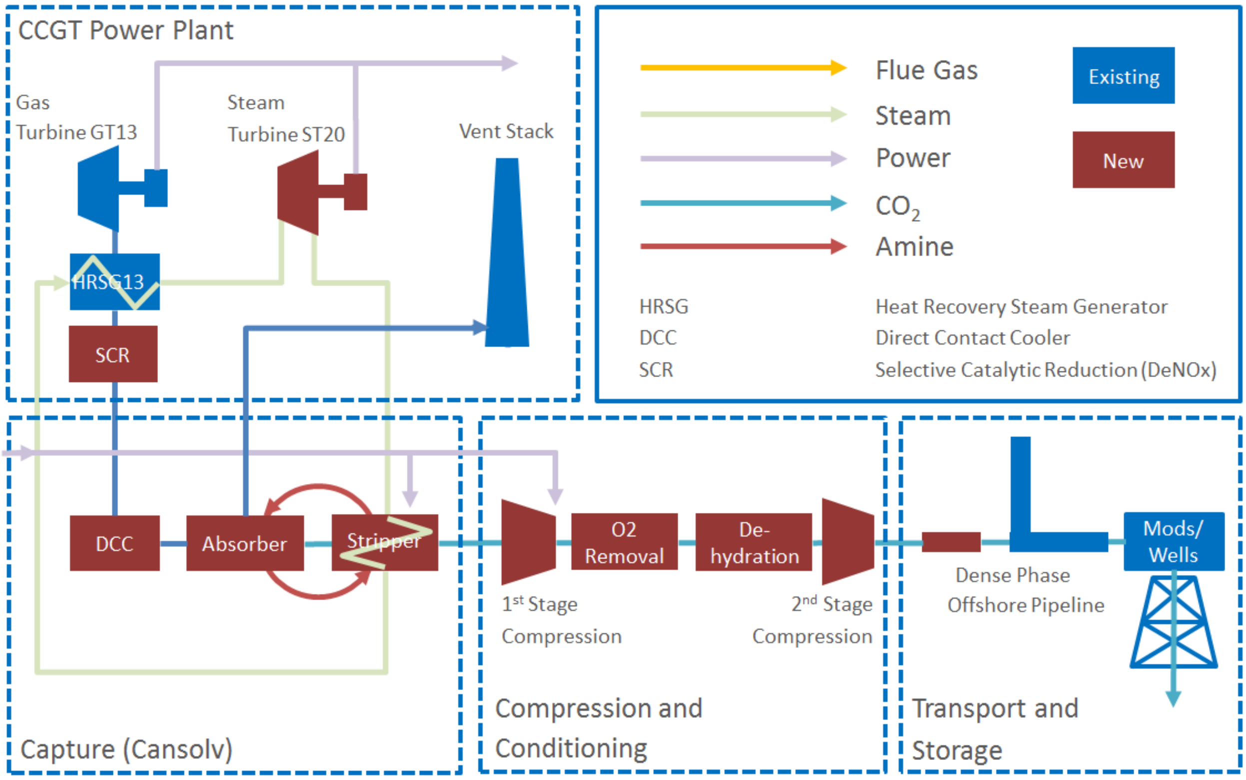

Figure 2-1: CCS Chain

2.1.1. Gas-Fired Power Plant

The existing Peterhead Power Station 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 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 no longer 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 less than 1 % of the total GT13 flue gas will continue to be emitted from GT13's flue, within the 90 m repowering stack. A Selective Catalytic Reduction (SCR) system will be fitted to existing HRSG13 to remove NOx in the GT13 flue gas (deNOx) before it is transferred to the carbon capture plant.

A new steam turbine generator with an output of approximately 135 MWe, denoted ST20, will also be installed. ST20 is sized to operate in combined cycle with GT13 and will output 135 MWe when operated in unabated mode. Under PCCS operation, low pressure (LP) steam will be diverted from the turbine and will be 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, LP steam can continue to be supplied to the carbon capture plant.

New auxiliary boilers will be installed within the power station as part of the PCCS project. The boilers will provide Medium Pressure (MP) steam to the entire site.

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

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

This is shown schematically in Figure 2-2 below.

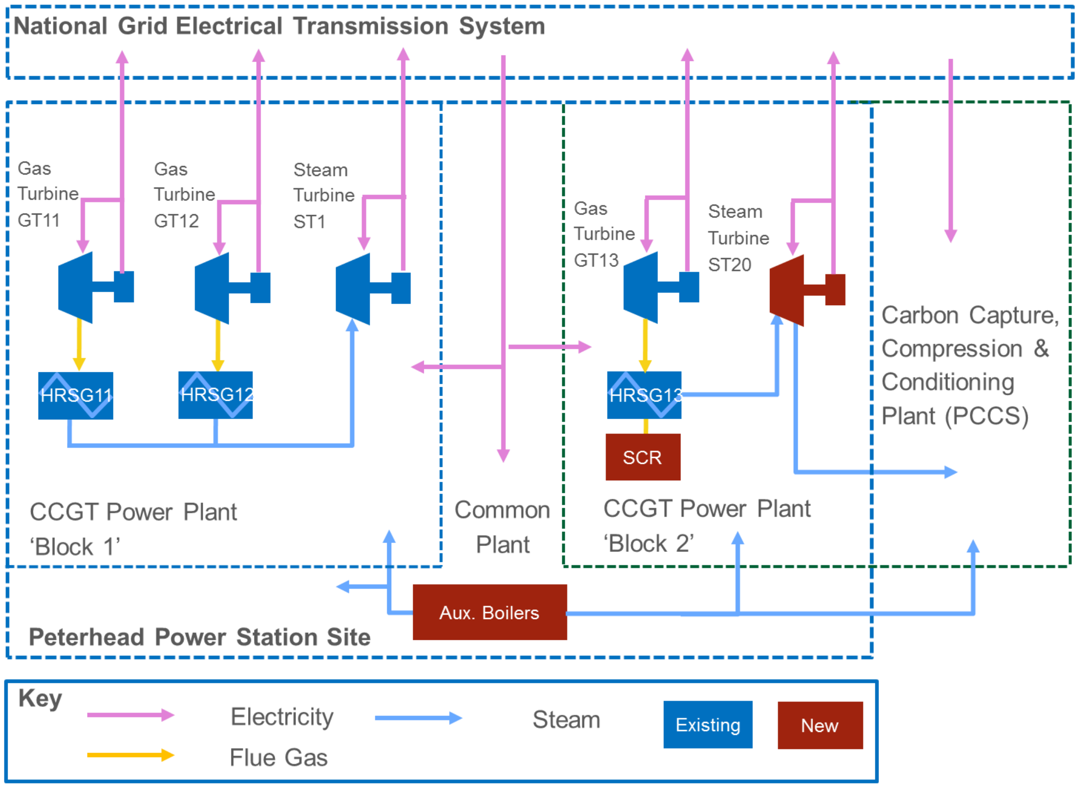

Figure 2-2: PCCS Configuration for Block 1, Block 2 and Common Plant

The Peterhead Power Station generating units export power onto the 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 System Operator (SO). However, the local onshore transmission assets are owned and maintained by SSE Transmission, part of the SSE plc group of companies.

Although the existing and new generating units will be redefined as belonging to Block 1 or Block 2 under PCCS, there are a number of existing common plant systems which will support both Block 1 and Block 2 operations after implementation of the PCCS project. These common plant systems include:

- HRSG feedwater system;
- Auxiliary steam system;
- Main cooling water system;

- Towns water system;
- De-mineralised water treatment plant;
- Station transformers, 4 off 132kV import connections;
- Station electrical distribution system;
- Fuel gas pressure reduction station; and
- Firewater system.

Further details on the Engineering FEED design can be found in APPENDIX 2. The metering solution developed to satisfy CfD and EU ETS requirements was developed after completion of the technical FEED design and can be found in the Surveillance, Metering, Allocation Strategy and Design Package – KKD 11.077 [5].

2.1.2. CO_2 Carbon Capture Plant

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 CO_2 leaving the capture plant for compression to the mass 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.

2.1.3. CO_2 Compression & Conditioning Plant

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. Water will be removed using molecular sieve technology. The conditioned CO_2 will then further be compressed to approximately 120 barg for export to the offshore transportation and storage system.

2.1.4. CO_2 Transportation

Following post-compression cooling, the resulting dense phase CO_2 stream will be transported directly offshore via a new short section of onshore pipeline which incorporates the pipeline landfall and a new offshore pipeline which will be tied in subsea to the existing Goldeneye pipeline. The chosen method for the pipeline landfall installation is Horizontal Directional Drilling (HDD). However, should the HDD technique encounter unexpected problems during execution, a conventional open cut technique would be adopted for the shore approach. The tie-in between the new pipeline and existing Goldeneye pipeline will be made via a flanged spool which can provide expandability in future.

The CO_2 will then be transported via the existing Goldeneye pipeline to the depleted Goldeneye hydrocarbon field for permanent storage.

2.1.5. CO_2 Storage

The CO_2 will be permanently stored in an underground store comprising the depleted Goldeneye gas field reservoir. The existing unattended production platform will require minimal modifications to be suitable for the proposed CO_2 duty. The five existing wells, served by the Goldeneye platform, are suitable for conversion to CO_2 injection wells and will provide sufficient injectivity for CO_2 storage. In practice, three primary injection wells are proposed with one well used for monitoring purposes. The fifth well will be abandoned.

Studies performed both prior to and during FEED indicate that the depleted field store can hold up to 34 Mt CO_2 and is adequate for the PCCS Project's required storage capacity of 15 Mt CO_2 over the 15-year operation period.

2.1.6. Methanol Injection

Methane hydrates are ice-like compounds that occur worldwide in sea-floor sediments. In most offshore hydrocarbon extraction applications, hydrate formation is controlled by injection of a thermodynamic hydrate inhibitor. Methanol and mono-ethylene glycol (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.

2.1.7. Full Chain Operations and Control Philosophy

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.

2.1.8. Full Chain 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 there is the potential that the UK Health and Safety Executive'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.

2.1.9. Waste Water Treatment Plant

Large quantities of surplus water will be generated in the Direct Contact Cooler where the water vapour in the gas turbine flue gas will be condensed. This water will contain traces of ammonia carried over from the SCR and the ammonia will have to be removed before the effluent can be discharged to sea. Bio-treatment has been selected as the preferred processing medium which converts the ammonia to nitrogen gas in a two-stage biological degradation process, The Waste Water Treatment Plant will be located adjacent to the compression and conditioning facilities and the treated effluent will be discharged via the existing power station discharge No. 4.

The possibility to treat the acid wash effluent containing quantities of amine was also investigated but the resultant water treatment plant design was highly complex, expensive, operator intensive and would have most likely have suffered from poor reliability. It was therefore decided at the end of the Execution Preparation phase to transport the acid wash effluent to a licensed offsite disposal facility for incineration. The Thermal Reclaimer Unit degraded amine bottom product will also be sent to the same location for disposal.

2.2. Location of the Project Infrastructure

The Peterhead Power Station is located on a coastal site less than 2 km south of the town of Peterhead. It is an operating CCGT power station. Peterhead Power Station is the only power station in this area and is used extensively by National Grid to balance their electrical grid system.

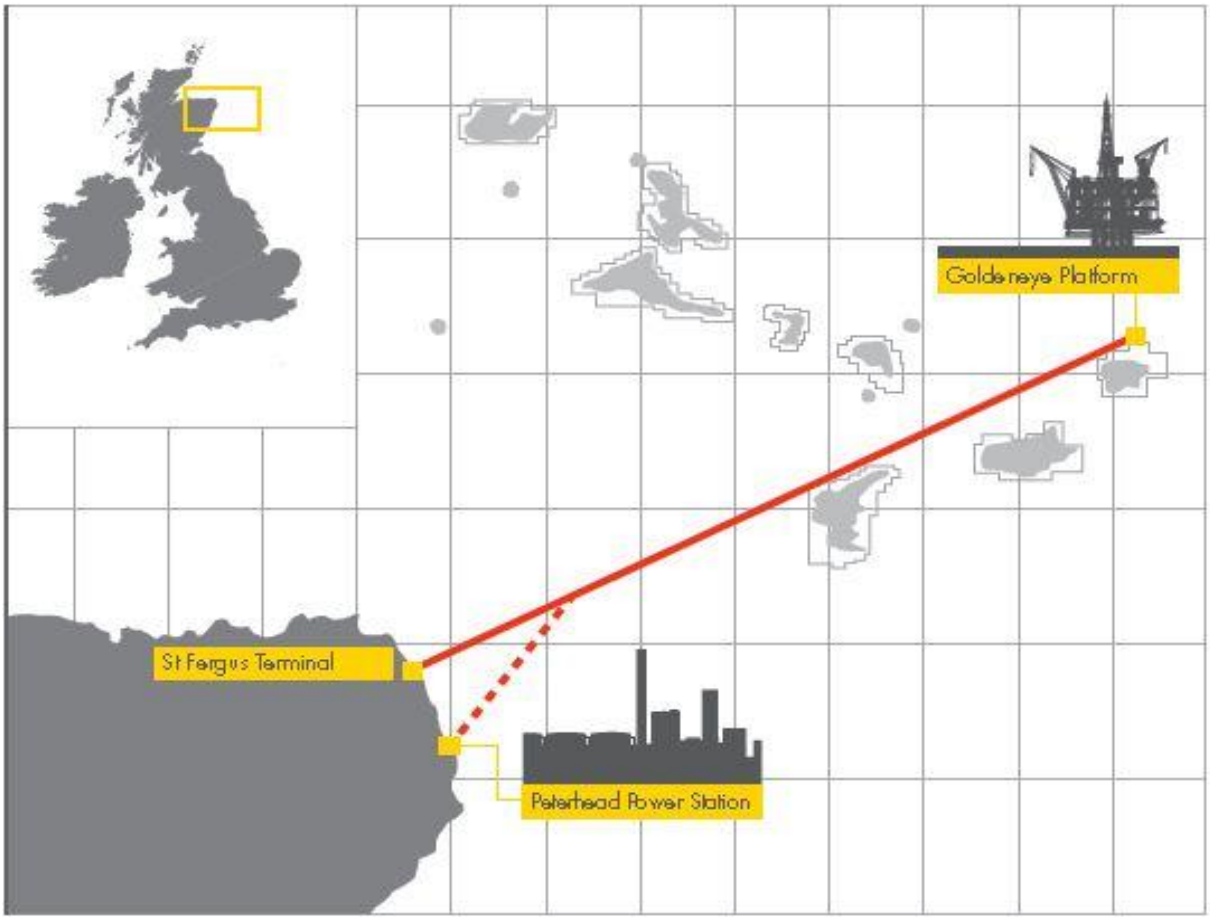

Figure 2-3: Location Map

The dried, deoxygenated CO_2 stream will be transported directly offshore via a new short section of onshore pipeline which incorporates the pipeline landfall and a new offshore pipeline which will be tied in subsea to the existing Goldeneye platform via the existing 20 inch (508 mm) Goldeneye pipeline. The existing pipeline was installed for dedicated gas field production from the Goldeneye field in 2004. The pipeline was used to carry natural gas to St Fergus from the Goldeneye field and its suitability for dense phase CO_2 transport was validated during FEED, subject to a pipeline integrity check through an intelligent pigging campaign to be conducted prior to start-up.

CO_2 storage will be in an underground store comprising the depleted Goldeneye gas field reservoir lying in the Outer Moray Firth area of the Central North Sea. This is located in the United Kingdom Continental Shelf (UKCS) blocks 14/29a and 20/4b. The field commenced production in 2004 and the last gas well was shut-in in 2011. Shell is a part owner and the Operator of the field. The injection site will be the Goldeneye offshore platform in the North Sea using existing wells which will be recompleted.

2.3. Parties Involved

Shell U.K. Limited (Shell) is currently the sole developer of the Peterhead CCS Project. Shell will be responsible for leading the project through the design, construct and operational phases for the entire Peterhead CCS chain from CO_2 capture to storage reservoir and will be accountable for the engineering, construction, operations, decommissioning and abandonment of the full end-to-end CCS chain. Shell will deal with a number of sub-contractors to deliver the project, including SSE Generation Limited, the Power Station owner.

Shell U.K. Limited is part of the Royal Dutch Shell group of companies. SSE Generation Limited is the owner and operator of the existing Peterhead CCGT power station site and will be responsible for the power generation in the project and will provide the supply of the NOx-free CO_2 laden flue gas through a Shell owned Selective Catalytic Reduction (SCR) system, as well as the steam and other utilities required for the Carbon Capture, Compression and Conditioning plant.

For the project to proceed, the Department of Energy and Climate Change (DECC), specifically the Office of Carbon Capture and Storage (OCCS), need to act as a funding client for the Project, and provide a capital grant as well as a Contract for Difference (CfD) arrangement during the operational phase under the UK Government's Electricity Market Reform (EMR) policy.

The main parties involved during the subsequent Detailed Engineering, Procurement and Construction (EPC) phase, or Execute phase, will be Shell, SSE and the EPC Contractors selected to deliver specific elements of the CCS chain scope.

2.4. Outline of Existing Facilities

A number of highly suited existing assets are already in place and available for use by the PCCS Project for the purpose of CO_2 capture and storage. This provides significant efficiencies in respect of Project cost and schedule. The principal existing assets to be used in the Project are the Peterhead GT13 gas turbine and exhaust stack and the Goldeneye offshore pipeline, platform and wells. Re-use of these facilities will reduce the environmental impact of pipe-laying and offshore drilling operations.

The most significant existing assets that will be re-used by this project include:

- GT13 gas turbine, generator, generator transformer, and associated auxiliary and ancillary systems at Peterhead Power Station;
- Fuel gas and electrical connections to the Peterhead Power Station site;
- The 170 m tall stack at Peterhead;
- 80 km of the offshore Goldeneye pipeline and riser;
- The Goldeneye platform;
- The Goldeneye wells and subsurface knowledge bank; and
- The MEG (Monoethylene Glycol, hydrate inhibition) injection and storage facilities at St Fergus as well as the pipeline / riser to the Goldeneye platform

2.4.1. 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; the main electrical system and also the existing 275 kV cable connection to the nearby National Grid Peterhead substation. 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 are complete 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 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 release 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.

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 2-4: Peterhead Power Station

2.4.2. Existing Pipeline

The Goldeneye pipeline was installed in 2004 and operated until December 2010. The offshore pipeline and wells are currently owned by the Goldeneye Production Joint Venture established to produce gas from the field under the existing production licence. Production from the field has now ceased and the transfer of ownership of the assets to the Peterhead CCS Project Venture Organisation is being progressed. The existing pipelines are described in Table 2-1.

Table 2-1: Existing Pipeline

Pipelines	
Length & Diameter	Length: offshore 101 km onshore 0.6 km (FLAGS route) Main pipeline : 20" (OD) MEG service line: 4" (NB)
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 pipeline corridor) Five pipeline crossings

The pipeline was cleaned and made hydrocarbon-free in 2013. A minimal quantity of solid deposits was recovered by the cleaning operations but samples were taken and analysed for chemical content. Based upon the results of this analysis it was concluded that no detectable corrosion had taken place and the pipeline was in a satisfactory condition for re-use. It was left inhibited with biocide with a protection life of 7 years.

Previous study work done during the earlier Longannet CCS Project FEED study concluded that the existing 20-inch Goldeneye pipeline was suitable for the transportation of dense phase CO_2. This work was reviewed in the PCCS FEED study and no significant issues were identified. For further details of the pipeline please refer to Section 7.3.

2.4.3. Platform

2.4.3.1. General Description

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 under 2,500 tonnes.

The plan dimensions of the four-leg jacket vary from 19.7x16 m at elevation +11.9 m (w.r.t. LAT) to 35x35 m at elevation –119 m. 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 X-braced with perimeter plan bracing only at the top and bottom levels.

2.4.3.2. Platform Orientation and Water Depth

The platform is orientated such that platform north is parallel to true north. The jacket faces are battered on three sides from the seabed at elevation –119 m w.r.t. LAT, to just below the deck at elevation +11.9 m w.r.t. LAT. From this point up the legs are vertical.

The water depth at the platform location is 119 m at LAT with a tolerance of 0.3 m. It was estimated that the seabed might subside up to 0.3 m during the life of the field due to reservoir depletion.

2.4.3.3. Existing Topsides Facilities

The platform is designed to operate as a 'Normally Unattended Installation' (NUI). It has accommodation for 12 personnel to facilitate periodic 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 telemetry communications links. The existing Goldeneye Offshore Platform Design Parameters are summarised below.

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

Parameter	Value
Design Concept	Full Wellstream Tieback to shore, for onshore processing of the gas and condensate Normally unattended platform offshore for control of wells / chokes, manifolding, metering and water / oil detection
Design Life	20 years (to be extended under the PCCS Project)
Wells	5 jack-up drilled wells with sand exclusion, 3 producers, 2 producer / observation wells. All wells drilled prior to commissioning and start-up (minimum is 3 wells prior to start-up)
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 manhours per year); additional visits for ad-hoc work

2.4.4. Existing Reservoir

The offshore Goldeneye gas condensate field was produced between 2004 and 2011 via a pipeline to onshore facilities at St Fergus. DECC formally approved Cessation of Production in Q1 2011. The PCCS Project intends to re-use the Goldeneye subsea pipeline system and all the offshore facilities for the transport, injection and storage of CO_2. Modifications required to the offshore facilities include the topsides pipe work, new Christmas Trees, new completions and new vents.

It is planned to inject CO_2 into the storage site at a depth greater than 2516 m (8255 ft) below sea level into the high quality Captain Sandstone formation in the North Sea. The current reservoir pressure is estimated at 2716 psia (187 bara) (January 2015 at a datum of 8400 ft TVDss) based on permanent downhole gauge information. After the injection of 15 million tonnes of CO_2 the reservoir pressure will rise up to approximately 3760 psia (260 bara).

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 over the platform to re-complete the wells for CO_2 injection. Four of the five wells will 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.

2.4.5. Existing Goldeneye Gas Processing Facilities at St. Fergus

The St Fergus gas plant has facilities installed to process the hydrocarbon fluids from the Goldeneye field, regenerate the MEG and export the hydrate and corrosion inhibitor to the platform via a 4" pipeline.

Table 2-3 provides a summary of the main Goldeneye facilities at St Fergus and their associated design parameters.

Table 2-3: Summary of Parameters for Existing Onshore Goldeneye Facilities at St Fergus

Parameter	Value
Standalone Reception / Process Facilities	Slugcatcher Surge Capacity 97 m^3 to 120 m^3 (variable weir height) Maximum condensate flowrate from slugcatcher: 200 am^3/hr Maximum aqueous flowrate from slugcatcher: 50 am^3/hr Gas Conditioning, drying using Molecular Sieve driers Water / MEG and Condensate separation Condensate stabilisation and flash gas recompression MEG recovery, regeneration and return Designed 35% above normal operating flow to process 5-day breakdown buffer in 14 days. Depletion Compressor (required from ~ 2.2 years after start of production)
Utilities	Hot oil system 2x100% WHRUs on existing Frame 5 gas turbines driving export sales gas compressors. Flare and vent (tie-in) Fuel gas Nitrogen Instrument air Electrical supply & distribution Drainage system
System Control	System (offshore and onshore) control from St. Fergus control room; local offshore control facility for offshore visits

The St Fergus gas plant contains redundant facilities that were used to:

a) Process Goldeneye gas and condensate;
b) Supply MEG and corrosion inhibitor on a continuous basis to the Goldeneye Platform; and
c) Regenerate the MEG separated with mainly condensed water from the inlet separation system.

The PCCS project will re-use some of the equipment associated with the storage and export of the MEG and corrosion inhibitor for hydrocarbon production for the purpose of delivering methanol to the Goldeneye Platform under PCCS operations.

The main items of equipment that will be re-used for PCCS are as follows:

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

It was a baseline assumption in FEED that the Goldeneye hydrocarbon facilities will remain decommissioned but will not be removed unless required for PCCS. However, there is also the potential for the infrastructure to be modified and utilised for other projects. This requires further consideration in the PCCS Detailed Design phase.

2.5. Scope Overview

2.5.1. General

The scope breakdown for the Peterhead CCS Project between the two primary responsible parties, SSE and Shell, is shown in the figure below.

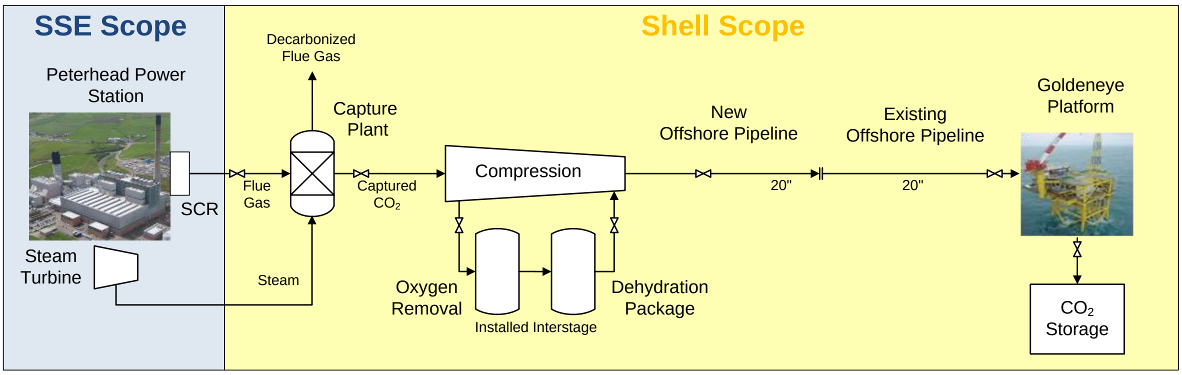

Figure 2-6: Scope Diagram between Key Responsible Parties

A list of the end-to-end Peterhead CCS chain links as considered during the FEED phase is provided below:

- Power Station (SSE's Generation Facilities);
- Carbon Capture, Compression and Conditioning (CCCC);
- Pipeline;
- Platform;
- Wells; and
- Reservoir.

2.5.2. Power Station

In the Execute project phase, the power plant scope of work shall segregate GT13/HRSG13 from the existing Block 1 steam system and provide steam for the new steam turbine, ST20, to form Block 2 of the power plant. Ducting shall be added to the exhaust gas path from HRSG13 to allow the gas to be drawn into the CCP. New Low Pressure (LP) steam supply lines and condensate return lines will take heat to and from the Carbon Capture Plant. A new auxiliary boiler system shall be installed, which will meet the CCCC plant's MP steam demand as well as providing the supply steam to the power plant's existing auxiliary steam consumers. Existing site utilities such as cooling water; raw water; fire water shall be modified to provide the necessary utility services to the CCCC plant. Modification shall also be required to the existing electrical network for utilisation with ST20 and the modified plant.

Demolition work shall also be carried out to remove redundant equipment from the power plant to provide space for the new CCCC plant.

2.5.3. Carbon Capture, Compression and Conditioning (CCCC)

The CCCC scope of work extends from the exhaust duct of the HRSG13 of the existing platform to the landfall connection onto the CO_2 export pipeline. The equipment in the area is split into three main process units:

- Pre-treatment (U-1000);
- Capture (U-2000); and
- Compression and Conditioning (U-3000).

It includes all the associated systems required for the above process.

In addition to the main CO_2 capture, compression and conditioning facilities there will be a Waste Water Treatment Plant to process the large quantities of surplus water generated by the capture process and make it suitable for discharge into the sea. Any process streams that are unsuitable for on-site processing will be transported by road tanker to a suitable licensed disposal site for further treatment.

Further details of the equipment to be provided can be found in Sections 5 and 6.

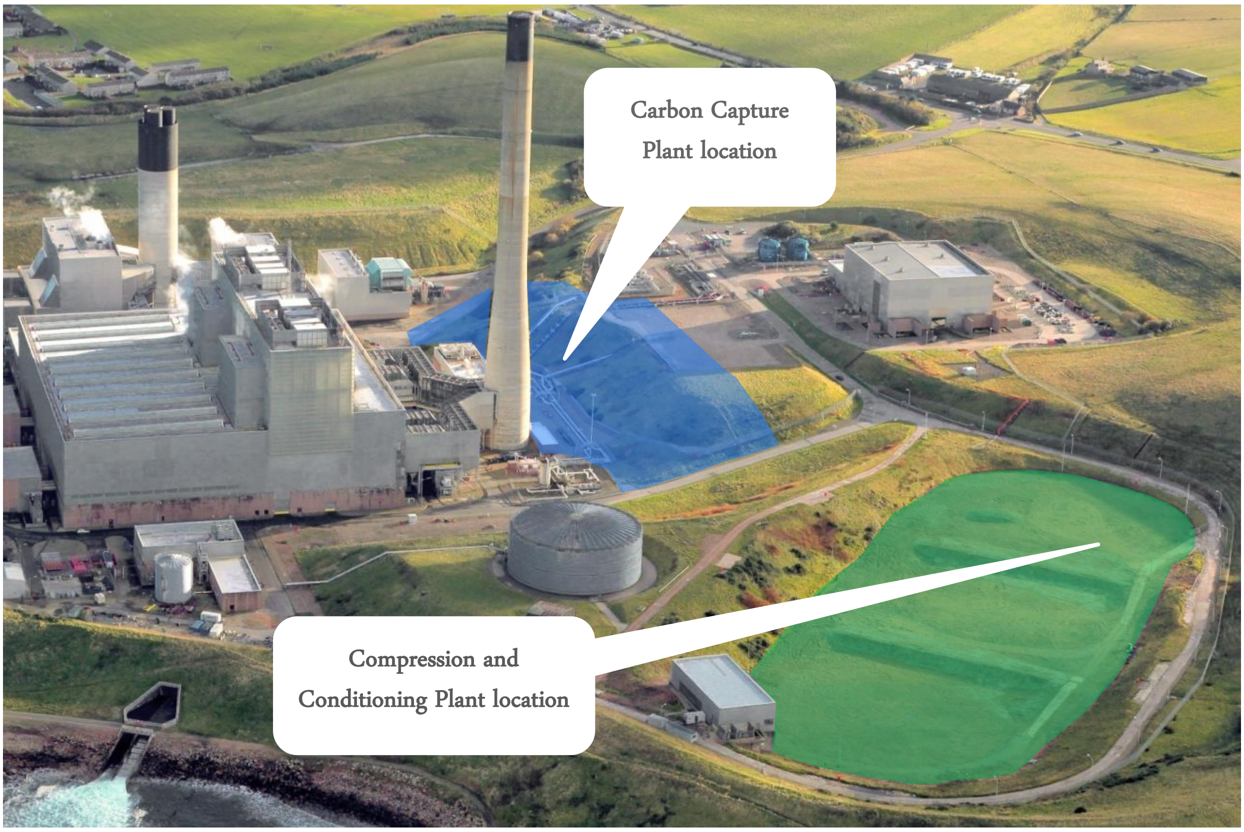

Figure 2-7: Carbon Capture, Compression and Conditioning Plant Location

2.5.4. Pipeline Systems

The subsea facilities shall comprise:

- New onshore pig launcher facility;
- 300m of onshore pipeline to HDD initiation point;
- 900 m HDD landfall tunnel;
- New 21.6 km 20 inch carbon steel CO_2 export pipeline from Peterhead Power Station to a subsea tie-in (approx. Kp19.6) to the existing 20" Goldeneye pipeline;
- New CO_2 export pipeline subsea flanged tie-in arrangement;
- New Sub-Sea 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); and
- Re-use of the existing 4 inch carbon steel MEG pipeline from St. Fergus which has been confirmed suitable for conversion to methanol transportation.

2.5.5. 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 CO_2 injection is completed, the platform will be decommissioned. The wells will be plugged and sealed and topsides and jacket will be removed so that the reservoir can be left with the CO_2 stored. Reservoir performance will be monitored post decommissioning by periodic boat-borne surveys. These surveys will be undertaken for a period of time that will be agreed with the relevant Authority. For planning purposes it has been assumed that seabed and seismic surveys will be executed by Shell at cessation of injection and again after some four to five years at the end of decommissioning. An expenditure allowance has been included to cover two further seabed surveys in the period up to 30 years after cessation of injection. This activity has been included in the OPEX cost estimate for the Project's Execute phase as detailed in the Cost Estimate Report – KKD 11.043 [9].

2.5.6. 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.

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 about 4 m^3/h to 5 m^3/h will be required. This will be provided by converting the existing Goldeneye glycol supply facilities at St Fergus to methanol storage and pumping. 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.

St Fergus asset will operate the storage and pumping facility. Methanol will be pumped on a call-off basis. The Peterhead CCS control room will contact the St Fergus control room when methanol injection is required. Remote monitoring of methanol pumping will be in place at the Peterhead CCS control room.

2.5.7. General/Common Facilities

Common facilities that are shared between the Project and other parties have only been considered at the Peterhead power station site. However, the CCS operating principle is to have a physically separate and independent operating structure whereby CCS operations and warehousing/workshops are monitored and controlled in separate control and workshop/store buildings remote from the equivalent existing PPS facilities.

Common facilities/support functions such as security gate house/access control, roads/car parking, and the likes are assumed to be shared with PPS operations, noting that SSE may also request for these to be independent to SSE operations.

The St Fergus methanol supply will be operated and maintained by the St Fergus Gas Terminal owners and there are no common facilities required at St Fergus.

2.5.8. Spare Parts and Special Tools

Spare parts identification and stock holding requirements will be decided following assessment of the final facility Reliability, Availability and Maintainability (RAM) model studies to be carried out during the Project's detailed design phase. RAM model data will be used to identify equipment contribution to availability, downtime, failure modes and to identify spare parts requirements including any long lead capital spares.

Spare parts will be categorised into three levels:

- Capital spares;
- Commissioning and start-up spares; and
- Two years' operating spares.

Spares identified as capital spares will be purchased with initial equipment purchase orders.

Accessibility and maintainability studies will be performed to optimise plant and equipment layouts and verified by 3D CAD modelling reviews.

Specialised tools required for equipment removal, strip down and maintenance will be identified and included in equipment purchase orders.

2.6. Interfaces

The main internal mechanical project interfaces are given in the figure below. The block flow diagram describes the various process systems and the physical boundaries between the contracting parties.

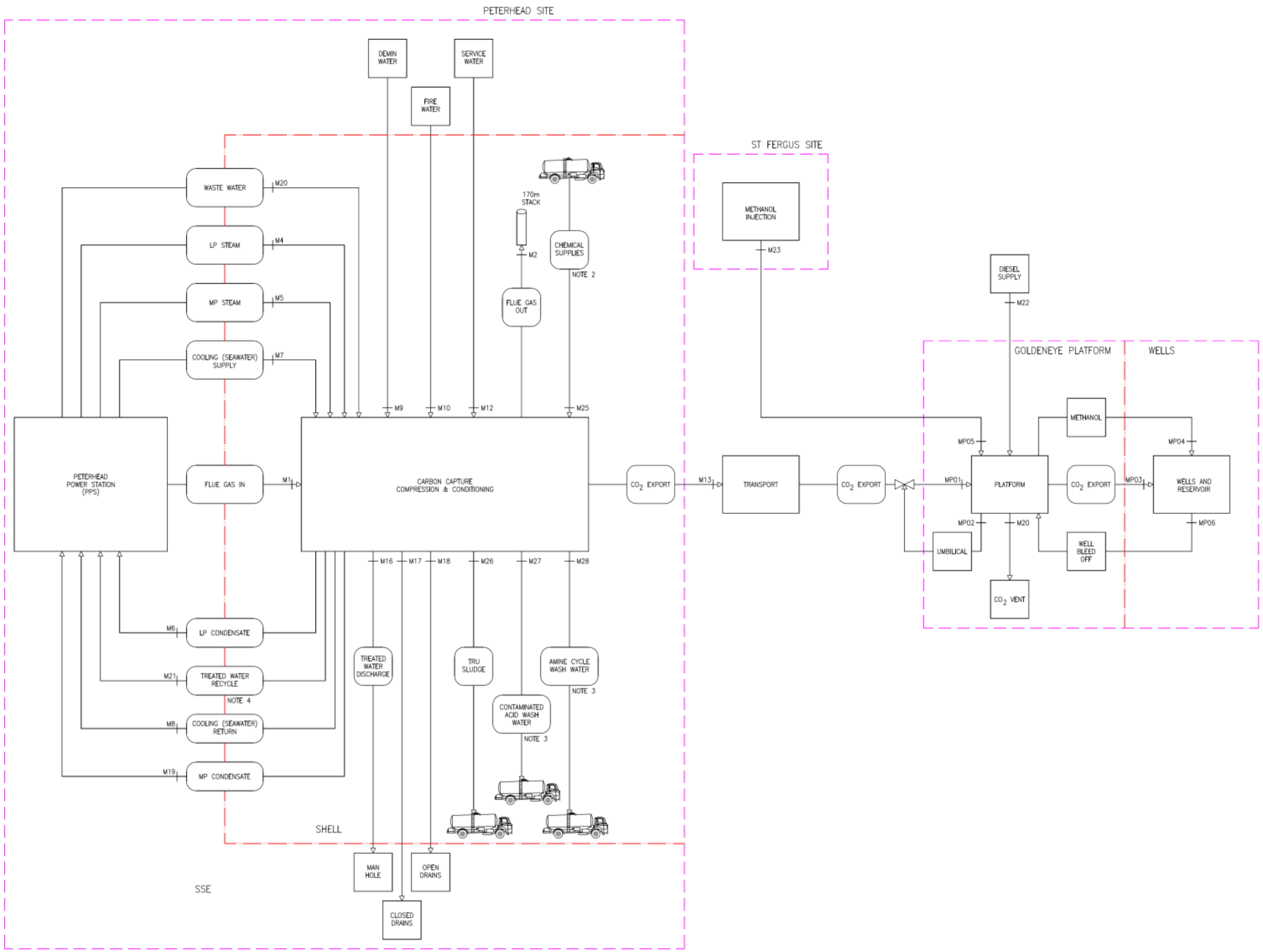

Figure 2-8: Block diagram of interfaces

2.6.1. Onshore Interface Points

The Carbon Capture Plant has interfaces with the following areas:

- The new and existing power plant equipment (GT13 exhaust gas, ST20 and various utilities);
- Existing National Grid transmission system equipment (power supply to capture plant);
- CO_2 pipeline equipment (CO_2 export); and
- Goldeneye platform, St Fergus site and Shell data networks (telecoms and data for control and monitoring).

The power plant has existing interfaces with the following areas:

- National Grid Equipment (power export);
- Incoming gas supply pipeline from the National Grid National Transmissions System (NTS);
- Cooling water intake and outlet; and
- Waste water disposal.

Modifications will be required at each of these locations and will be required to be further detailed and controlled during the Execute phase.

Information on each interface (tie-in) can be found within the document Peterhead CCS (Onshore) Interface Schedule [10].

2.6.2. Offshore (Goldeneye Platform) Interface Points

The Goldeneye Platform has interfaces with the following areas:

- CO_2 pipeline;
- Methanol pipeline;
- The Subsea Isolation Valve (SSIV) manifold;
- The wells (CO_2 injection, methanol injection and monitoring & instrumentation); and
- Peterhead CCS, St Fergus site and Shell data network (telecoms and data for control and monitoring).

As there are a small number of key offshore interfaces a summary of the locations and the responsible parties have been identified in the list below:

Table 2-4: Main Offshore Interfaces

System	Medium	Location	Responsible party
CO_2 in	Gas	Tie-in to existing riser upstream of the new platform ESD valve (weld)	Offshore EPC
CO_2 out	Gas	Tie-in to the Well Christmas Trees downstream of the choke valves (flanged spool piece)	Offshore EPC

System	Medium	Location	Responsible party
Methanol in	Liquid	Tie-in into existing 4-inch riser before new ESD valve (new ESD valve onto existing flange)	Offshore EPC
Methanol out	Liquid	Tie-in to the Well Christmas Trees downstream of the choke valves (flanged spool piece)	Offshore EPC
Umbilical to Sub Sea Isolation Valve manifold		Umbilical pull-in and connection to Topsides Umbilical Termination Unit (TUTU)	Pipeline & Subsea contractor to provide and install TUTU and to pull-in umbilical
Umbilical hydraulics to platform HPU	Liquid	Hydraulic connections TUTU – Platform HPU	Pipeline & Subsea contractor
Subsea SSIV instrumentation	Electric Signals	Tie-in of instrument cable from TUTU to platform ICSS	Offshore EPC
Communications	Comms signals	Goldeneye to Peterhead and other communications systems	Communications System Integrator
Integrated Control and Safety System		Goldeneye Control room to Peterhead CCS Control room	Honeywell as part of Offshore EPC scope

3. Design Criteria

3.1. Design Life

The design lifetime of the facilities required by the Project shall be 15 years from commencement of PCCS operations under the CfD.

3.2. Design Class

A design class workshop was conducted prior to commencing the FEED study with the objective of improving understanding, agreement and communication on the size, type and cost of the new plant for the Project. The main drive of the design class evaluation exercise was to "provide an optimum fit-for-purpose scope to meet the business needs". The design class workshop was carried out in accordance with Shell's internal project management processes which consider selection of one of three design classes to suit four key performance criteria. The most appropriate design class is selected for each performance criteria – i.e. different design classes can be applied to each performance criteria. Shell's standard guidance on the application of design class characteristics to individual project aspects is summarised in Table 3-1 below.

Table 3-1: Shell Standard Design Class Characteristics

	Class 1	Class 2	Class 3
Performance Categories	Will meet premises only at one set of design conditions; will not meet off-design cases	Selected process streams or systems will be upgraded to meet off-design cases	Will meet premises at all identified conditions, design and off-design cases
Capacity	-20% / +0%	-10% / +10%	0% / +20%
Expandability	None	Selected Streams	Considered
Capacity Utilisation	< 85%	85 to 95%	> 95%
Operability and Maintainability	No Turndown	Moderate Turndown	High Turndown

A high level summary of the selected design classes as applied to the PCCS pre-FEED design in the design class workshop is presented in Table 3-2 below:

Table 3-2: Summary of Design Class Workshop

	Class 1	Class 2	Class 3
Performance Categories	Will meet premises only at one set of design conditions; will not meet off-design cases	Selected process streams or systems will be upgraded to meet off-design cases	Will meet premises at all identified conditions, design and off-design cases
Capacity	Based on a blanket 5% overdesign included in current design, as per Design Basis. No more overdesign in facilities.		
Expandability	No expandability is proposed for the carbon capture plant design	Space is allocated for 2nd CO_2 compressor	
Capacity Utilisation	CO_2 compressor and flue gas booster fan are not spared: a high reliability		Carbon capture plant main rotating kit is spared. RAM to be used to justify

	Class 1	Class 2	Class 3
	figure is required to meet target. Requires shutdown of equipment to repair		holding other high Capital Expenditure (CAPEX) spared equipment
Operability and Maintainability		Planned shutdowns to follow SSE maintenance cycle. Sparing to be adjusted accordingly to meet availability target	Auto start available on wells

Design Class is not applicable to the Offshore and Pipeline scopes.

3.3. Design Cases

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 Capture and Compression Plant during the most favourable ambient conditions.

The 'Normal operation' case corresponds to the output from the Power Plant and Capture and Compression Plant when operating at the reference ambient conditions at the Peterhead Site.

The 'Turndown' case corresponds to the operating scenario where the CO_2 output of the CO_2 compressor equates to the minimum injection flow rate for the wells. This is approximately equivalent to GT13 operating at 65 % output and the CO_2 export at 70 % of the normal operation case.

3.4. Design Margins

The following table shows the percentage design margin applied to the Design Load Max case for the major items of equipment in the Project. Note that the Design Case is based on the maximum possible output from the power plant and Capture and Compression Plant during the most favourable ambient conditions.

Table 3-3: Design Margins

Equipment	Design Margin %	Notes
Booster fans	0	On design gas throughput
DCC column	0	On gas throughput
DCC pump	20	On flowrate
DCC cooler	20	On surface area

Equipment	Design Margin %	Notes
Gas-Gas Exchanger	10	On flowrate and duty
CO_2 Absorber	5	On flue gas flowrate
Thermal Reclaimer Unit	50	On processing rate
CO_2 Compressor	0	On flowrate
LP Steam and Condensate systems to CCP	10	On flowrate
CCP closed loop cooling system	10	On flowrate
CCP heat exchangers	10	On surface areas
CCP Pumps	10 (min.)	On design flowrate
Demineralized Water supply from power plant to CCP	10	On peak flow rate

3.5. Availability

During FEED, a Reliability, Availability and Maintainability (RAM) study was undertaken to create an End-to-End reliability model for the PCCS project. The RAM model 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 results of the RAM modelling performed show the PCCS chain's designed availability to be approximately 85% based upon the end of FEED design. The highest impact on the full PCCS chain availability is as a result of the PPS station outages for gas turbine GT13 scheduled maintenance. The power plant outages provide an opportunity to align some of the necessary PCCS equipment maintenance with the power plant outages without impacting on the overall PCCS availability. The most significant source of downtime in the CCCC plant design is attributed to the CO_2 compressor and booster fan, resulting from the lack of designed redundancy in this equipment. This decision was made as a result of the cost / benefit analysis performed during FEED.

3.6. Flexibility

The project has a secondary driver to demonstrate operating flexibility to support clean gas power with greater flexibility plus reliability than renewables.

Although full chain process modelling has been undertaken during FEED considering the transportation and injection of CO_2, due to the novelty and complexity of the overall CCS chain system, the extent to which the system can be operated flexibly can only be investigated by accurately determining all likely system interactions and constraints once operations have commenced.

3.7. Application of New Technology and Techniques

CCS individual technologies are largely proven and safe, the primary challenges relate to full chain and integration aspects. It is assumed that no significant new Research and Development (R&D) or technology development releases will be required during the Execute Phase of the Peterhead CCS project. The novel aspects of the project that have been identified in the bid to DECC include the Power Station Tie-in, Capture, Compression and Conditioning, Onsite Waste Water Treatment, Transport, Injection and Monitoring scope. For further details of the novel technologies considered on the project please refer to separate Key Knowledge Deliverable (KKD) 11.064 - Technology Maturation Plan [6].

In addition to new technology, the regulatory regime for CCS is still in development. Although much work was done in FEED to address likely regulatory requirements and compliance with EU ETS, CfD, etc., these requirements will continue to mature as the Project progresses and it is anticipated that further effort will be required during Detailed Design to satisfy these requirements which are still developing in terms of detail and the interpretation of how they should be applied to CCS projects in the UK.

4. Power Plant (Generation)

4.1. Power Plant System Description

Peterhead Power Plant is an operational CCGT station comprising of three gas turbines each with an HRSG providing steam to a common steam system powering a steam turbine. The gas turbines are single fuel, burning natural gas from the UK National Transmission System (NTS). Exhaust gas from each of the HRSGs is currently routed to a dedicated flue within the 90 m repowering stack and emitted to atmosphere.

Cooling water for the steam turbine condenser and other closed loop cooling circuits is a once-through configuration taken from the sea utilising main cooling water pumps and returned to the sea via the outfall on the north side of the plant.

Electricity generated by each turbine generator is exported to the GB transmission grid via the Peterhead 275 kV substation, located approx. 2 km to the west of the power plant, on dedicated circuits.

In the Execute project phase, the power plant scope of work shall segregate GT13/HRSG13 from the existing Block 1 steam system and provide steam for the new steam turbine, ST20, to form Block 2 of the power plant. Ducting shall be added to the exhaust gas path from HRSG13 to allow the gas to be drawn into the CCP. Existing site utilities such as cooling water; raw water; fire water shall be modified to provide the necessary utility services to the CCCC plant.

The new plant shall be designed to meet UK and EU legislator requirements, British and international standards, SSE internal standards and also GB Grid Code requirements.

A brief description of the main items of the power plant is provided below. In addition to the equipment considered below, the existing facilities within the power plant will also be modified to provide utilities such as town’s water, fire water and demineralised water. Process design information for the utilities required by this scope element is provided separately in Section 6. Sections 5 and 6, and the associated reference documents appended to this document, present a snapshot of the PCCS project design at the end of FEED. This design will be further developed in the Detailed Design phase of the Project. The control and instrumentation modifications required are described in Section 12.2.3.

For further process information refer to the Process Description (CCS Project “Generation Facilities”) [11].

4.2. Gas Turbine (GT13)

The gas turbine will have a lifetime extension carried out by the Original Equipment Manufacturer (OEM), Siemens. Siemens also offer various standard gas turbine upgrade packages to improve efficiency and gross output of the base unit and the decision was taken at the end of the Execution Development Phase to incorporate the Compressor Mass Flow

(CMF+) and Service Pack 7 (SP7) upgrades into the base Project scope. The rationale for this change is explained in the FEED Decision Register – KKD 11.020 [4].

It is anticipated that following the lifetime extension and GT upgrade work, the gas turbine will be capable of producing circa 290 MWe at the project reference conditions. Electrical output information for GT13 post upgrade is provided based upon typical Siemens data. The impact of the Gas Turbine Upgrades will be considered further in the Detailed Design phase to reflect the amended scope. This will include inspection of existing equipment, such as the air inlet filter housing, to determine its suitability to meet the project design life and any changes, if required, shall be carried out.

The fuel gas line to GT13 will also be modified to include a meter with the accuracy as required to support the clean electricity output calculation for the fuel supply to the gas turbine.

4.3. Heat Recovery Steam Generator (HRSG13)

A Selective Catalytic Reduction (SCR) system shall be incorporated into the process to achieve the reduction of the NOx content of the exhaust gas that will be passed on to the CCP. The catalyst modules, support structure and ammonia injection equipment shall be installed in HRSG13, utilising the existing space between the high pressure evaporator and the intermediate pressure superheater. HRSG13 was originally installed to be SCR ready which significantly simplifies the required retrofit works for PCCS

Further information on the proposed process can be found on the P&IDs included in Reference [12].

4.3.1. Process Conditions

The SCR system is required to reduce the NOx level in the flue gas provided to the CCP and shall be designed for the exhaust gas produced by the GT13 as summarised in Table 4-1:

Table 4-1: SCR Inlet Gas Properties[1]

Main Parameters	Units	Current GT 100% Load Max	Current GT 65% Turndown Case
Ambient temperature	**°C**	5	8
Ambient pressure	**mbar**	1040	1013
GT output	**MW**	281	167
GT generated LHV efficiency	**%**	38.5	34.5
GT exhaust gas flowrate	**kg/s**	710	512
GT exhaust gas temperature	**°C**	580	569
HRSG outlet temperature	**°C**	100	100
HRSG outlet pressure	**mbar**	1040	1013
Volumetric flowrate	**Nm^3/s**	558.4	402.6
Volumetric flowrate dry	**Nm^3/s**	516.4	373.8
Volumetric flowrate	**Am^3/s**	743.2	550.2
CO_2 mass flowrate	**te/h**	**153.1**	**99.9**
CO_2 captured rate	**te/h**	**137.8**	**89.9**
Composition - Molar Basis			
CO_2	**mol %**	3.88	3.51
O_2	**mol %**	12.81	13.45
H_2O	**mol %**	7.53	7.15
N_2	**mol %**	74.88	74.99
Ar	**mol %**	0.90	0.90
Sum of constituents	**mol %**	100.00	100.00
Mol wt	**[-]**	28.50	28.50
SO_2*	**ppmv dry**	1.4	1.4
NO**	**ppmv dry**	20.4	18.5
NO_2 (x% of total NOx)***	**ppmv dry**	8.7	7.9
CO	**ppmv dry**	0.0	87

Notes:

[1] The quoted SCR inlet gas properties do not include the impact of the Gas Turbine Upgrades and will be updated in the Detailed Design phase to reflect the amended scope.

*Corresponds to max GS(M)R S level of 50 mg/Sm^3 (typically ~10% of this) (UK gas system Sm^3: 15°C and 1.01325 bara)

**NOx ppm values based on 50 mg/m^3NOx *reported* as NO_2 at 15% dry:

***x% of *actual* NOx as NO_2 - assumed or test results

The SCR system is required to reduce the NOx level in the flue gas provided to the capture plant in order to reduce the amine consumption, whilst maintaining a system pressure drop of less than 7 mbar at all conditions. The SCR system catalyst shall have a minimum service life of at least four (4) years. The ammonia slip into the exhaust gas shall be less than 2 ppmv (dry).

4.3.2. Ammonia Storage and Transfer

Ammonia storage, transfer and tanker offloading facilities shall be constructed to facilitate the operation of the SCR. Further details of the proposed system configuration can be found in Reference [13] (PFS – Aqueous Ammonia Storage and Transfer to SCR System). An ammonia storage tank of 80 m^3 has been proposed in FEED. This is sufficient for approximately 14 days of SCR system operation at full load. The system will preferably be designed to use aqueous ammonia solution to avoid the increased health & safety risks which would be introduced if handling pure ammonia on site.

4.4. Water and Steam Modifications

As designed, the existing configuration of the Block 1 CCGT includes significant sharing of steam and water systems between HRSG11, 12 and 13 - including feed-water systems, drainage and steam supply pipework. Consequently a number of steam and condensate pipework systems associated with the existing Block 1 CCGT shall require modification to connect HRSG13 directly to the new Steam Turbine ST20.

The modifications shall make HRSG13's steam and water system independent from Block 1 with the exception of the common feedwater systems which will be shared.

Further information can be found on the process flow scheme diagrams, References [14] and [15] attached in Appendix 2.

4.4.1. Process Conditions

Process conditions for the Block 2 related facilities can be found on the Heat and Material Balance (Generation Facilities) document [16].

4.5. Steam Turbine ST20 Systems

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 capture plant in as efficient a way as possible. The new steam turbine shall utilise as far as possible the existing Unit 2 steam turbine electrical export circuit.

The scope of work includes but is not limited to:

1. A new steam turbine with a nominal rating of 135MWe;
2. New electrical systems including a new generator, generator transformer and unit transformer (and associated control & protection equipment);
3. Connection to the grid via the existing steam turbine 275 kV export cable and associated 275 kV Circuit Breaker (CB), M30;
4. Steam turbine auxiliary and ancillary systems, including reuse of equipment where appropriate;
5. Modifications to the existing structural frame necessary to support the new turbine generator;
6. A new LP steam extraction system including pipework to the capture plant;
7. New LP condensate-return pipework from the capture plant to the condenser; and

8. Modifications to the existing condenser necessary to operate in conjunction with the new turbine generator.

Refer to P&IDs in Reference [15] for further information.

The new steam turbine shall have a combined HP/IP (Intermediate Pressure) casing and double flow LP casings. Steam to the CCP will be extracted from the IP/LP crossover line, with a control valve limiting the pressure of the steam supplied to the CCP.

4.5.1. Process Conditions

Table 4-2 shows the process conditions for the steam turbine with the CCS plant operating with the GT13 at 100% baseload at reference conditions.

Table 4-2: ST Design Conditions

Parameter	Units	Value
HP pressure upstream stop valve	bara	105
HP temperature upstream stop valve	°C	525
HP flow rate upstream stop valve	kg/s	82
HP turbine exhaust pressure (RH pipework pressure drop dependent)	bara	33.75
IP (HRH) pressure upstream stop valve	bara	31.5
IP temperature upstream stop valve	°C	525
HRSG IP flowrate to add to cold reheat	kg/s	15
HRSG LP steam temperature	°C	235
HRSG LP steam flowrate	kg/s	9
HRSG LP pressure upstream ST admission valve	bara	4.5

Further information can be found on the Heat and Material Balance (Generation Facilities) [16].

The ST20 steam turbine system shall be designed to meet the LP steam requirements of the CCP plant as specified in Table 6-1. Condensate is returned to the power plant as described in Section 6.2.2.

4.6. Cooling Water (CW) System

The cooling water system scope of work for the PCCS Project includes modifications to the existing cooling water systems in order to provide the quantities of cooling water that are necessary for operation of the Carbon Capture, Compression and Conditioning plant, while ensuring appropriate CW supply to the existing power plant Block 1 and Block 2 condensers and auxiliary cooling requirements.

The scope for the Cooling Water system modifications is expected to include but is not limited to:

1. Modification of CW pipework in the valve-pit to install new take-off for CCP supply pipework (installation of valves and pre-fabricated piping sections);

2. Modification of structural steelwork in the valve-pit to permit access and lifting capability for maintenance;
3. Installation of a new CW supply pipe from the valve-pit to the booster pump station;
4. Installation of 3 x 50% duty booster pumps;
5. Installation of a new CW supply pipe from the booster pumps to the CCP;
6. Implementation of control system and any associated hardware necessary to ensure balance of CW flows between all users.
7. Installation of new CW discharge pipe from CCP to the existing outfall complete with control valve to control pressure upstream within the CCP; and
8. Modifications to the existing CW outfall.

Further information can be found on the Main and Auxiliary Cooling Water System report [17]. And in the to the utility flow scheme diagram [18], attached in Appendix 2.

4.6.1. Process Conditions

The cooling water system modifications shall be designed to supply water to the CCP as per the requirements in Table 6-5, whilst also supplying the following power plant demands:

Table 4-3: Power Plant CW Demands[1]

Stream	Mass Flow (t/h)
GT/HRSG auxiliary CW flowrate	1,850
Unit 1 condenser: **U1 ST ACW system**	35,000[4] (CC2 mode) 1,200
New ST20 condenser (GT13 base-load):	~17,800 (without extraction to CCP)

[1] The impact of the Gas Turbine upgrades on the Power Plant CW demand was not evaluated in FEED and will be updated in the Detailed Design phase to reflect the amended scope.

Control valves shall be installed to ensure that flowrates can be balanced over the full operational envelope of each item of plant. The system shall be designed to operate with 3 main CW pumps where possible.

An analysis of the system hydraulic behaviour under dynamic conditions shall be carried out in the Execute phase of the Project to verify the system design.

4.7. Auxiliary Boilers

The existing auxiliary boiler house shall be demolished to create plot space for the construction of the new CCP and a new auxiliary steam boiler system which shall be installed to provide steam for the following users:

- Unit 1 Steam Turbine Gland Steam Seal (GSS) system (required on start-up only);
- Fuel gas heaters in the Pressure Reducing Station (PRS);
- Administration and control block heating and ventilation;
- Auxiliary steam header warming;
- Auxiliary boiler feed water tank heating;
- HRSG building heating and ventilation;

- Steam Turbine ST20 gland steam seal system (required on start up only); and
- MP steam to feed the CCP Thermal Re-claimer Units (TRUs)
- MP steam to feed the CO_2 vaporiser unit, in the conditioning and compression area.

It is anticipated that the auxiliary steam system shall comprise of 4 x 33% duty packaged containerised boilers firing on natural gas supplied from the National Grid NTS. The system will include:

- A burner management system which will be integrated with the power plant control system;
- Fuel gas conditioning including pressure reduction if necessary; and
- Emissions monitoring and flue gas ducting to a suitable location.

4.8. Electrical Systems

The electrical systems for the power plant shall be modified to suit the new configuration and output of the steam cycle. Single line diagrams, references [19], [20] and [21] are attached in Appendix 2, to show the equipment and the configuration of the main electrical systems for the modified plant.

Existing switchrooms shall be utilised for accommodating the new switchgear required for the steam turbine and other power plant modified systems. Space shall be provided by the removal of obsolete equipment and cables.

The power plant's earth mat installation shall be reviewed and modified to incorporate the requirements of the CCCC plant. Refer to Section 6.9.9.3 within the Utility Description section of this document for further information.

5. Carbon Capture, Compression and Conditioning

5.1. General

This section provides process design information for the Carbon Capture, Compression and Conditioning (CCCC) scope. This area is split into three units:

- Pre-treatment (U-1000);
- Capture (U-2000); and
- Compression and Conditioning (U-3000).

Process design information for the utilities required by this scope element is provided separately in Section 6.

This document should be read in combination with the following documents:

- Heat and Material Balance [22];
- Process Flow Schemes, as detailed in each section;
- Equipment Summary List [23].

Sections 5 and 6, and the associated reference documents appended to this document, present a snapshot of the PCCS project design at the end of FEED. This design will be further developed in the Detailed Design phase of the Project.

Further information can be found on the associated Heat and Material Balance document [22].

5.2. Pre-Treatment (U-1000)

5.2.1. Introduction

This section provides information on the Peterhead CCS pre-treatment unit also referred to as U-1000. The scope includes the booster fan, flue gas pre-treatment upstream of the CO_2 absorber and treated gas reheating before it is routed to the 170 m high 'tall stack'.

The main purposes of the pre-treatment plant are to:

1. Route flue gas from the existing duct to the downstream CO_2 capture unit and finally to the 170 m tall stack;
2. Cool down flue gas to the required temperature for the carbon capture process; and
3. Heat up treated flue gas to ensure sufficient draft and proper dispersion in and from the stack.

5.2.2. Process Description

The gas pre-treatment system comprises the following major components:

- Booster fan (K-1001);
- Direct Contact Cooler (DCC) (C-1001); and
- Gas-Gas Heat Exchanger (E-1001).

The process description refers to the Process Flow Schemes (PFS) [24].

5.2.2.1. Gas Pre-Treatment

The flue gas transferred to the Carbon Capture Plant is taken from the outlet duct of the Heat Recovery Steam Generator (HRSG13). A booster fan (K-1001) provides sufficient pressure to drive the flue gas through the Carbon Capture Plant to the 170 m tall stack.

For PCCS operations, GT13's flue within the existing 90 m Repowering Stack, will be kept open to atmosphere, thereby minimising the CCP's potential to cause damaging pressure excursions in the HRSG. Efficient operation of the carbon capture process requires maximising the flue gas transfer from GT13 to the Carbon Capture Plant, whilst avoiding drawing in atmospheric air (reverse flow) through GT13's flue.

The FEED design proposes that the flow exiting from GT13's flue will be controlled to be approximately 0.12 % of the GT13's total exhaust flow. The quantity of the flue gas directed to the CCP will be controlled to match the gas turbine exhaust flow after allowing for the flow requirement to GT13's flue. This will be achieved by a combination of controlling the booster fan's speed and partial recycling of the booster fan's flow. This approach is considered to be feasible and will be developed further in Detailed Design.

Flue gas from the booster fan flows to the Gas-Gas Heat Exchanger (E-1001) where it is cooled to 70°C, whilst heating the treated flue gas from 30 to 75°C. A rotary regenerative heat exchanger is proposed (similar to the type applied in power stations to preheat boiler air) in which a slowly rotating element transfers heat from the hot side to the cold side. A purge and scavenge fan (K-1003A/B) is used to maintain a low level of leakage between the two sides.

The flue gas then flows into the DCC (C-1001), where it is further cooled to 30°C by direct contact with recirculating water. It is critical to saturate and cool the flue gas prior to feed to the CO_2 Absorber Tower to ensure proper CO_2 absorption and prevent excessive water evaporation from the amine solution in the CO_2 absorber tower.

The very low level of sulphur in the flue gas means that levels of sulphites formed in the pre-scrubber will be low. For plants with high sulphur flue gas, the sulphites enhance absorption of NO_2 in the Direct Contact Cooler (DCC). For this plant, because of the low sulphites level the current design basis does not assume that any NO_2 will be removed within the DCC. Water condensed from the flue gas in the bottom section will contain traces of ammonia entering the system in the upstream Selective Catalytic Reduction (SCR) system. In view of this, the pre-scrubber effluent water will require further treatment in the Waste Water Treatment Plant (WWTP) before it is discharged into the sea.

The treated flue gas leaving the top of the CO_2 absorption flows to the Gas-Gas Heat Exchanger (E-1001) where it is warmed up to 75°C before being released through the 170 m tall stack to the atmosphere.

5.2.2.2. Pressure Profile

A booster fan provides enough pressure to drive the flue gas through the CCP.
In order to develop a FEED design for the booster fan, certain pressure drops were assumed for downstream equipment. Figure 5-1 shows the pressure profile used for the booster fan (design case).

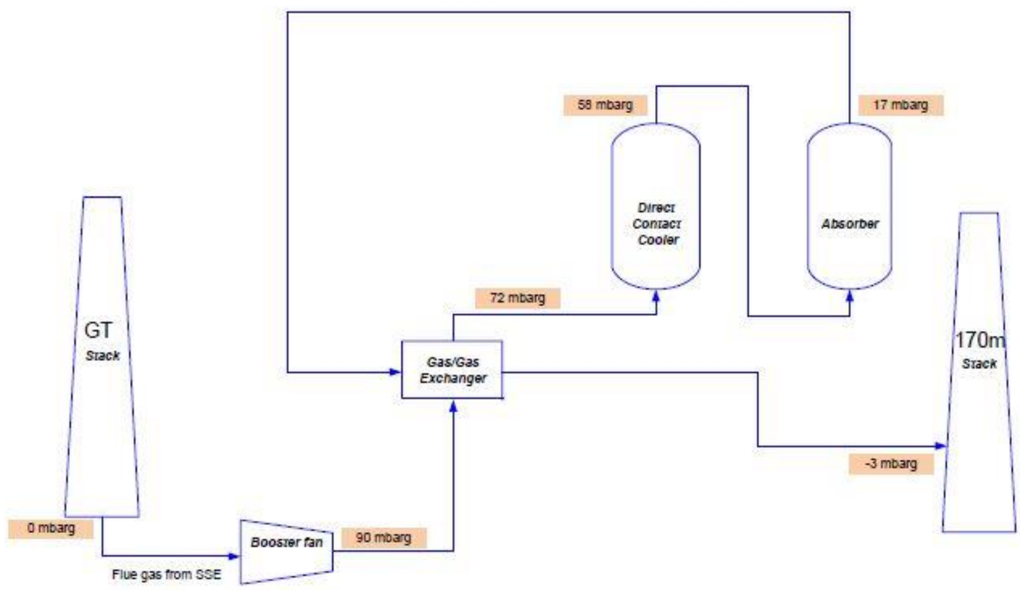

Figure 5-1: Pre-treatment Unit pressure profile

The pressure profile will be confirmed in Detailed Design based on the final duct layout used.

5.2.3. Flue Gas Ductwork

5.2.3.1. Ductwork Design

The PCCS ductwork scope starts at the HRSG13 exhaust, including the transition section, and ends at the duct battery limit to the 170 m tall stack.
FEED level design for the ducting covered the following main topics:

- Bill of quantities for the ducts, including ducting size, lengths, construction materials, bends, supports, bracing, painting, expansion joints, insulation, liners, turning vanes, slide bearing plates, gaskets etc.
- Identification of studies that are expected to be provided by the EPC Contractor during the Execute Phase.
- Specification guidance. E.g. detailed description of criteria that the design must meet, e.g. for expansion joints, allowable movements, seal levels, type/method of construction, design code, allowable construction tolerances, materials, etc.
- Conceptual layout drawings (or isometrics) of the ducting, including but not limited to, load and movement data, guides, hanger and anchor point positions and access locations.
- List of recommended standards for design of the ductwork and associated ancillaries.
- Recommended inspection checks to be completed by the Project during operations, including leakage checks.
- Recommended form of preassembly and fabrication for shipment.

5.2.3.2. Material Selection

The ductwork material selection base case is carbon steel with a flake glass lining. The FEED design has selected a coating which has track record in FGD ductwork service. However, this coating needs to be applied on-site to mitigate potential damage from ductwork flexing during installation. Such a solution would introduce a major schedule concern, and the construction methodology and the requirement for duct lining should be revisited during the Project's Detailed Design phase.

Some of the ducting will not be internally lined, for example between the HRSG and the rotary heat exchanger, due to the low potential for condensation of water and therefore low risk of corrosion. If the ducting is not insulated, then internal coating will be necessary for all surfaces. The selected lining shall be suitable for the flue gas conditions and design temperature. The internal lining and inspection requirements which will need to be developed during Detailed Design for application in the Operations phase will need to take account of any internal stiffening, guide vanes and attachments installed within the ductwork to ensure that the lining fully coats all surfaces, eliminating hot spots where localised corrosion can occur. Application of this coating is expected to create a hazardous atmosphere. The EPC Contractor will be required to ensure appropriate safeguards are put in place, particularly if the coating is being performed at site. External protection will be required in line with the project specifications and shall be suitable for the ductwork's design temperature.

The gasket selection for the ductwork flanged connections needs to ensure the integrity of the joint and flake glass lining on the flange faces is maintained.

5.2.3.3. Fabrication & Construction

Due to limited available space at site and to avoid impacting on either ongoing power plant activities or other PCCS construction activities, it is envisaged that the ducting will be fabricated and coated in complete sections at a local fabrication yard and then transported to the site in completed sections.

Applying and inspecting the coating at the selected fabrication yard provides a controlled environment which will minimise future operational issues due to corrosion. As there is good access from the harbour to site, an option would be to ship in completed sections of ductwork. The ductwork sections would then be lifted into position and bolted together.

The design shall allow installation of the ductwork without applying any load to the equipment connections, as even temporarily supporting the ductwork from other equipment during construction can result in permanent distortion of the sealing surfaces.

The fabrication and construction methodology needs to be reviewed further in Detailed Design before selecting the optimum ductwork design and installation method.

i. The preferred option is to complete fabrication of the ductwork at a suitable fabricator offsite: either sited locally, or more remotely with the ductwork then shipped to Peterhead harbour.
   This allows the section of ductwork to be fully fabricated, coated and inspected offsite leaving it to be lifted into position and bolted up at site.
ii. The main alternative is to fabricate the ductwork in panel sections which are then assembled at site.
   However, this would significantly increase the number of joints and leakage paths and have the internal coating susceptible to damage during transportation and installation.

A combination of fabrication options i and ii can be considered if an assembly site next to the Peterhead Power Station is used to assemble pre-fabricated panels into ductwork sections. The completed sections are then transported onto site and lifted into position as noted above.

A test procedure needs to be developed prior to commencing construction to cover integrity testing of the sections of ductwork fabricated offsite as well as a system test of the installed system. The procedure will include leakage acceptance criteria.

5.2.3.4. Transportation & Site Access

There is good access from Peterhead harbour to the power station which should enable transportation of completed sections of ductwork should a remote off-site fabrication method be preferred. The maximum dimensions of the ductwork require to comply with the transportation limits which were identified during FEED. In the event that the proposed ductwork dimensions would slightly exceed the specified transportation limits, these limits will be reviewed to ascertain if there is scope to increase the defined limits.

Access within the site also needs to be considered when identifying the limiting size of ductwork sections to be transported, as well as the impact on other construction activities. The construction sequence for the ductwork and associated structural support needs to be reviewed during Detailed Design with cognisance taken of access and construction requirements of other equipment.

5.2.4. Technology Selected

The following section describes the design basis for the technology selected for the Peterhead CCS project.

5.2.4.1. Booster Fan

Both axial and centrifugal fans are technically suitable for this application. During FEED a centrifugal fan design was used by the FEED sub-contractor, as this offered greater flexibility for configuring the ducting layout. This is advantageous for plant retrofits such as PCCS where space is constrained and the physical locations of many equipment items are already fixed. The final selection will be made by the EPC contractor during Detailed Design, based on the duct configuration and commercial factors. Two 100 % fans have been specified in the project documentation, but a 1 x 100 % fan has been preferred after review of the FEED study RAM results indicated there would be insignificant benefit from installation of a second fan.

5.2.4.2. Direct Contact Cooler Design

In this plant, due to the low sulphites level the current design basis does not assume any NO_2 removal will take place within the Direct Contact Cooler (DCC).
The Direct Contact Cooler (DCC) includes one circulating water loop which is sufficient to cool down as well as saturate the flue gas.

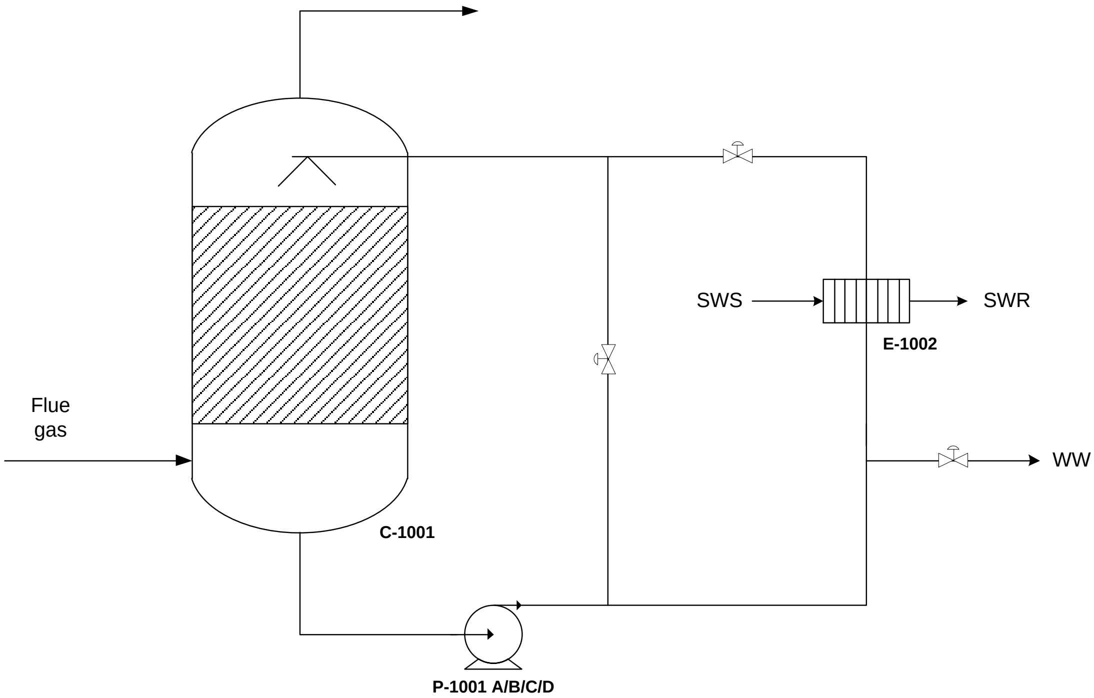

Figure 5-2: Direct Contact Cooler Process Schematic

5.2.4.3. Gas-Gas Heat Exchanger Leak Rate

Rotary regenerative exchangers, by the nature of their design, have a certain amount of gas leakage between the different sides.

Based on information provided by an original equipment manufacturer, it has been assumed a leakage rate of less than 0.6% should be achievable. To achieve this low leakage rate a controlled leakage philosophy should be applied which, according to the vendor, has been proven on a number of air preheaters installed in existing power stations.

The low leakage system comprises a purge and scavenge fan, which exhausts from the treated gas outlet and passes it back under positive pressure into the hot side.

The leakage rate has been included in the final Heat and Material Balance document [22].

5.2.5. Design Cases, Design Margins and Turndown

The pre-treatment unit is designed for the design case as per Table 5-2. The minimum and normal operating cases for the feed to the pre-treatment section are also included in Table 5-2. The maximum case is considered to be the design case which corresponds to the gas turbine maximum flow (very low ambient temperatures and high pressures corresponding to maximum mass flow) while the normal case is the expected case. The turndown case is based on 65% of max design case CO_2 production.

Heat and Material Balances are provided for all three cases in the Heat and Material Balance document [22]. The maximum design case is used for all equipment sizing. Design margins applied for sizing the equipment are summarised in Table 5-1.

Table 5-1: Design Margins

Equipment	%	Notes
Booster fan	0	On design gas throughput
DCC column	0	On gas throughput
DCC pump	20	On flowrate
DCC cooler	20	On surface area
Gas-Gas Exchanger	10	On flowrate and duty

5.2.6. Feed and Product Specifications

For the FEED specification, reference is made to the Heat and Material Balance document [22].

The interface that sets the specification for the feed to the pre-treatment section is flue gas from the power station.

The process conditions and composition of the interface stream (DCC outlet) feeding the CO_2 absorber unit is provided in Table 5-3.

Table 5-2: Gas to Pre-treatment Unit

Battery Limit Conditions (Gas Inlet)	Units	Value Normal Case GT 100%	Value Turn down GT 65% (Note 1)	Value Design Load Max (Note 2)
Gas Inlet Flowrate	kg/s	685	512	710
CO_2 Mass Flowrate	t/h	145.5	99.9	153.1
Capture CO_2 flow	t/h	130.9	89.9	137.8
Operating Temperature	°C	100	100	100
Operating Pressure	bara	1.013	1.013	1.040
Composition				
SO_2	ppmv dry	1.4	1.4	1.4
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

Battery Limit Conditions (Gas Inlet)	Units	Value Normal Case GT 100%	Value Turn down GT 65% (Note 1)	Value Design Load Max (Note 2)
Ar	vol%	0.90	0.90	0.9
CO	ppmv	0	87	0
total NOx	ppmv	1	1	1
HCl	vol %	0	0	0
HF	vol %	0	0	0
NH_3	ppmv	5	5	5
Dust Load	mg/Nm^3	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 ppmv ammonia but expected value is 2 ppmv.**

Table 5-3: DCC Flue Gas Outlet Data to CO_2 Absorber

Battery Limit Conditions (DCC Gas Outlet to CO_2 Absorber)	Units	Normal Case (Note 1)	Turndown Case (Note 1)	Design Case
Gas Inlet Flowrate	kg/s	663	498	688
CO_2 Mass Flowrate	t/h	144	99	150
Temperature	°C	30	30	30
Pressure (Note 1)	bara	1.063	1.041	1.063
Molecular Weight		28.89	28.85	28.90
Composition				
SO_2	ppmv dry	<1.4	<1.4	<1.4
CO_2	vol %	3.97	3.63	4.03
H_2O	vol %	3.98	4.08	3.98
O_2	vol %	13.32	13.89	13.30
N_2	vol %	77.79	77.47	77.75
Ar	vol %	0.94	0.93	0.94
CO	ppmv	0	0	0
Total NOx	ppmv	1.0	1.0	1.0
HCl	vol %	0	0	0
HF	vol %	0	0	0
NH_3	ppmv	0.8	0.8	0.8
Dust Load	mg/Nm^3	0	0	0

Notes:

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

5.2.7. Interfaces and Effluents

5.2.7.1. Utility Requirements

Table 5-4: Sea Water

Parameters		IN	OUT
		Sea water	Sea water
From		OSBL	DCC Cooler
To		DCC Cooler	OSBL
		Liquid	Liquid
Operating Temperature	°C	15	27.5
Operating Pressure	bara	3.91	2.91
Mass Flow	kg/h	5,114,612	5,114,612

5.2.7.2. Flue Gas Product

Table 5-5: Flue Gas Product

Parameters		IN	OUT
		Treated gas from Acid Wash	Treated gas from Acid Wash
From		Acid Wash Section	Gas-Gas Exchanger
To		Gas-Gas Exchanger	170 m tall stack OSBL
		Vapour	Vapour
Operating Temperature	°C	30	75
Operating Pressure	bara	1.026	1.009
Mol Flow	kgmol/h	82,972	83,510
Mass Flow	kg/h	2,341,405	2,356,723
Actual Volume Flow (Average)	m^3/h	2,038,547	2,394,921

5.2.7.3. Waste Water

Table 5-6: Waste Water from DCC Cooler (E-1002)

Parameter	Units	Value
Temperature	°C	20
Pressure	bara	5.0
Mol Flow	kgmol/h	3,393
Mass Flow	kg/h	59,344
Actual Volume Flow (Average)	m^3/h	60.0

5.2.7.4. Power

The following duties are anticipated.

Table 5-7: Power Requirement

Equipment	Unit of measure	Rated power
P-1001 A/B/C/D	kW	302 kWe pump (4 x 33 %)
K-1001 A/B	kW	8,039 (1 x 100 %)
K-1002 A/B	kW	36 (2 x 100 %)

5.2.7.5. Service Water

Service water is required to provide sufficient level in the pre-scrubber before start-up. The town's water pumps have been designed with a rated flowrate of 22 m^3/h, with both pumps operating, permitting filling in a 24-hour period. Under normal operating conditions no service water consumption will be required, because water continuously condenses from the flue gas as it is cooled.

5.2.8. Process Control Requirements

5.2.8.1. Booster Fan (K-1001)

The FEED design proposes that the flow exiting from GT13's flue within the existing 90 m repowering stack will be controlled to achieve a relatively small flowrate, approximately 0.12 % of the GT13's total exhaust flow. To achieve the desired flows, the booster fan's output will be regulated by recycling of the fan's flow, using a control damper in the recycle duct and by controlling the fan's speed by using a variable speed drive.

Flow conditions in GT13's flue will be continuously monitored by specialist flow instrumentation which is suitable for use in the low flow conditions that result from PCCS operations. The fan's control scheme will use signals from the instrumentation to automatically adjust the output of the booster fan to achieve the desired flow from GT13's flue.

Starting and stopping the booster fan has the potential to cause variations in the outlet conditions of GT13. A dynamic study was performed during FEED to investigate the ability of the gas turbine and associated equipment including the HRSG to tolerate pressure and flow fluctuations within the gas path, caused by booster fan operation. This study did not identify any likely adverse impacts on the operation of the power plant equipment. This should be confirmed during Detailed Design for the proposed EPC Contractor's equipment.

In the case of sudden stopping, the flue gas from the CO_2 absorber is suddenly diverted to the existing flue that is dedicated to GT13 in the 90 m repowering stack. When this happens, the stack contents are at low velocity and are relatively cold and will initially not provide the normal draft of a warm stack.

In the case of starting, the minimum capacity of the fan is instantly applied to the total system.

For FEED, a VSD solution has been selected which is anticipated to provide the necessary flow control for starting and running conditions. This will be confirmed by CFD modelling and the final selection of the instrumentation and associated control system which will be carried out in Detailed Design during the Execute phase of the project.

5.2.8.2. Direct Contact Cooler (C-1001)

The outlet temperature of Direct Contact Cooler will depend on the amount of re-circulating water to the column. The basic process control parameters for the Direct Contact Cooler operation are the flow rate and temperature of the water fed to the column. The Direct Contact Cooler outlet temperature and re-circulating water temperature are designed in a master-slave configuration in combination with the total water flow controller. The temperature control/flow control system is a decoupled system whereby the effect of the flow control is to move both control valves in the same direction, and the effect of the temperature control is to move the control valves in opposite directions. This is achieved by flow control value=a*b and temperature control value=a*(1-b) where "a" is output of the flow control and "b" is the output of the temperature control. Based on the output of the control system, the required flow to DCC will be defined.

The liquid level of the Direct Contact Cooler sump may be considered as a control parameter or a monitoring parameter, depending on the different design requirement. The waste water flow will be controlled by the sump level controller.

5.2.8.3. Typical Interlocks

The following lists the most important interlocks required for the safe operation of the pre-treatment section.

- On low-low sump level, P-1001 will stop and the valve to the waste water treatment will close.
- On high-high sump level, the valve to waste water treatment will open.

5.2.9. *Safeguarding Requirements*

A safeguarding philosophy has been applied to develop the instrumented relief devices and safeguards by instrumentation which together forms the process safeguarding system. Safeguarding considerations are to be reviewed and completed in the next project phase during Detailed Design.

Initial indications of key safeguarding criteria that have already been identified are the following:

- Interface with Power Station, pipeline and third party equipment (e.g. backflow protection).
- Potential release of hot flue gas to atmosphere.

- Potential breakthrough of hot flue gas to the carbon capture plant.

5.3. Capture (U-2000)

5.3.1. Introduction

Cansolv has developed the process design associated with the CO_2 capture scope of the Carbon Capture Plant system. The amine-based capture plant solvent selected for use as a basis for the FEED phase PCCS design was Cansolv's proprietary solvent.

The CCP is designed to capture 90 % of the CO_2 contained in the flue gas entering the absorber.

Some of the information contained in the following references has been restricted due to the proprietary nature of the Cansolv solvent.

The capture element of the FEED design is described in more detail in the associated Process Flow Schemes (PFSs) for the capture process – found in References [25], [26], [27], [28], [29], [30] and [31].

The equipment list for the capture scope can be found in Reference [23].

5.3.2. Process Description

The CO_2 Capture System comprises the following major components:

- CO_2 absorption section;
- Water wash section;
- Acid wash section;
- CO_2 stripper;
- Amine filtering;
- Ion Exchange Unit (IX); and
- Thermal Reclaiming Unit.

The following process description for the capture scope should be read in conjunction with the capture Process Flow Schemes referenced in Section 5.3.1 above.

5.3.2.1. CO_2 Absorption

On exiting the pre-treatment system, the pre-treated flue gas is ducted to the CO_2 absorber (C-2001). CO_2 absorption from the flue gas occurs by counter-current contact with Cansolv absorbent solvent in a vertical multi-level packed-bed lined concrete CO_2 absorber tower.

The flue gas entering the absorption section of the tower will have sufficient pressure to overcome the pressure drop in the tower packing and flue gas re-heater before being discharged to atmosphere as lean flue gas.

The Absorber Feed Pumps (P-2005 A/B) deliver CO_2 lean amine from the Lean Amine Tank (T-2001) through the Lean Amine Cooler (E-2001) to the top of the CO_2 absorption section. The lean amine is cooled in Lean Amine Cooler (E-2001) to prevent water loss from evaporation into the flue gas, to maintain an overall water balance in the Cansolv absorbent DC inventory and to maximise capture efficiency.

The treated flue gas leaving the top of the CO_2 absorption section will pass through a water wash section and acid wash section before being released through the 170 m tall stack to the atmosphere.

5.3.2.2. Water Wash Section

A water wash packed bed section is included at the top of the CO_2 absorber to capture volatile or entrained amine mist and to condense water from flue gas to maintain the water balance in the system. Wash water is drawn from a chimney tray and is re-circulated to the top of the packed section, via the Water Wash Cooler (E-2003), by the Water Wash Pumps (P-2003 A/B). The water wash cooler reduces the temperature of circulating wash water, which minimises water loss and enhances capture efficiency of the volatile amine. Water condensed from the flue gas into the wash water section overflows from the chimney tray down into the absorber sump. The treated flue gas leaving the water wash section flows upwards to acid wash section.

5.3.2.3. Acid Wash Section

An acid wash packed bed section is included above the water wash section to capture mainly light amine components but also other entrained amine containing mist and potentially evaporated amine from the water wash section to minimise the emission level to the 170 m tall stack. The acid wash pH is maintained at 3 to maximise the light amine components capture. An acid and water mixture is drawn from a chimney tray at approximately 30°C and 1.033 bara is re-circulated to the top of the packed section, by the Acid Wash Pumps (P-2001 A/B) at 30°C and 1.028 bara. Captured amine and other volatile components will be converted into salts by the sulphuric acid, which will suppress the vapour pressure and minimise the emission of amine to the environment. The amine salt will be purged by a take-off from the chimney tray located at the base of the acid wash section of the absorber and routed to the waste water treatment system. The flue gas leaving the acid wash will be reheated to approximately 70°C preventing plume formation and enhancing dispersion of light amine components and other amine degradation product emissions, before being released to atmosphere. The vent from the vacuum package of the TRU will also contain light amine components; therefore it is routed to the acid wash section so that any amine degradation products generated can be captured.

5.3.2.4. CO_2 Stripper

The rich amine is collected in the bottom sump of the CO_2 absorber at 35°C and 1.063 bara and is pumped by the Rich Amine Pumps (P-2002 A/B/C) to 9.52 bara and heated in the Lean/Rich Exchangers (E-2002 A/B) to approximately 114°C recovering heat from the hot lean amine discharged from the CO_2 Stripper (C-2002). Rich amine exiting the lean/rich exchangers is piped to the CO_2 stripper for amine regeneration and CO_2 recovery.
The rich amine enters the column under the CO_2 reflux rectification section and flows onto a gallery tray that allows for disengagement of vapour from the rich amine before flowing down to the two stripping packing sections via the trough type liquid distributor.

The rich amine is stripped of CO_2 by LP steam at 118.5°C and 2 bara in the CO_2 Stripper Reboilers (E-2004 A/B/C/D/E) flowing in an upward direction counter-current to the rich amine.

Lean amine flowing to the bottom packing section of the CO_2 stripper is collected on a chimney tray and gravity fed to the reboilers. A mixture of water vapour and lean amine flows from the reboilers back to the stripper sump, underneath the chimney tray. Water vapour flows upwards through the chimney tray to strip the CO_2 while the lean amine collects in the bottom sump.

The Lean Amine Pump (P-2004 A/B) delivers the lean amine from the CO_2 stripper sump at 2 bara to the lean amine tank at 2.75 bara after being cooled in the lean/rich amine heat exchangers to 40°C.

Water vapour in the stripper, carrying the stripped CO_2, flows up the stripper column into the rectification packing section at the top, where a portion of the vapour is condensed by recycled reflux at 25°C and 1.95 bara to enrich the overhead CO_2 gas stream.

Excess water with amines that may accumulate in the amine loop is bled off as stripper reflux to the Effluent Treatment Package (A-4801).

A mist eliminator is installed below the rectification section of the stripper to minimise water droplets and amine entrainment with the CO_2 rich gas.

The rectification section contains three bubble-cap trays instead of packing because the reflux flowrate is too small to provide the minimum wetting required for the packing. The section is also narrower than the stripper main section because of the lower liquid flowrate compared to the stripping section.

The CO_2 stripper overhead gas is partially condensed from approximately 94°C and 1.95 bara to 25°C and 1.75 bara in the Overhead Condensers (E-2005 A/B). The partially condensed two-phase mixture gravity flows to the Reflux Accumulator (V-2001) where the two phases separate. The reflux water is collected and returned via the Stripper Reflux Pumps (P-2006 A/B) to the CO_2 stripper rectification section. The CO_2 product gas from reflux accumulator is piped at 25°C and 1.65 bara to the Compression and conditioning plant. The reflux is pumped back on level control to the top of the CO_2 stripper and a small portion of the reflux flow is sent to the IX Package A-2100.

5.3.2.5. Amine Filtering

The amine may pick up dust or other insoluble contaminants as it flows through the various unit operations comprising Cansolv's Carbon Capture Plant system design. Such contaminants could, in the long run, accumulate in the Ion Exchange (IX) column or foul the heat exchanger surface areas. Hence, a cartridge type filter (S-2001) will process a slip stream of lean amine pumped from the lean amine tank to the absorber to remove any entrained suspended solids.

The filtered amine will then flow to the IX (A-2100), when required, or back to the Lean Amine Tank (T-2001) when the IX unit is not processing amine. Filtered amine can also be sent directly to the TRU if the IX is not in operation.

As the concentration of suspended solids is expected to be low, it was deemed unnecessary to install a back-up filter for use when replacing cartridges in the main filter.

5.3.2.6. Ion Exchange (IX) Unit

Trace contaminants present in the gas, such as SO_2 & NO_2, form ionic Heat Stable Salts (HSS) that must be removed from solution. The IX unit (A-2100) is designed to remove HSS from the Cansolv DC Absorbent. These salts are continuously formed within the absorbent, primarily due to residual amounts of SO_2 being absorbed in the absorbent and converted to sulphite, thus neutralising some of the amine via an acid/base reaction; a part of the absorbent is hence inactivated for further CO_2 absorption. Although a certain level of HSS is tolerable within the absorbent, excess HSS must be removed. Excess HSS removal is achieved by use of the IX unit. The IX is also designed to remove small amounts of HSS formed due to oxidative amine degradation (mainly organic acids).

The CO_2 IX unit process is a batch process which involves five main steps:

1. Salt Loading
2. Amine Recovery Rinse
3. Buffering Rinse
4. Regeneration with caustic soda

5. Excess Caustic Rinse.

Together, these five steps constitute an IX cycle.

5.3.2.6.1. Salt Loading

During the salt loading phase, the lean amine is passed through the IX Amine Cooler (E-2006) before being sent to the ion exchange column. The amine enters the bottom of the column and flows in an upward direction and the HSS adsorb onto the active sites of the resin. The purified lean amine exits the column with a lower salt concentration, and is piped back to the lean amine tank / thermal reclaimer unit. Once all of the resin active sites are occupied by the HSS, the resin is saturated and is no longer capable of further salt adsorption. The amine fed to the IX column is filtered through a cartridge-type filter.

5.3.2.6.2. Amine Recovery Rinse

After the salt loading phase, some of the amine remains trapped in the interstitial spaces between the resin beads and in the expansion volume of the bed. Before the resin is regenerated, the column is rinsed using reflux to recover the remaining amine in the column. The reflux is passed in a down flow direction, which displaces the trapped amine. The reflux is heated in the IX reflux heater and stored in the IX reflux tank before being pumped to the IX unit. The diluted lean amine is piped back to the lean amine tank.

5.3.2.6.3. Buffering Rinse

After the amine recovery rinse phase, an additional volume of heated demineralised water is introduced at the top of the column to increase the recovery of amine which is piped back to the lean amine tank.

5.3.2.6.4. Regeneration

A 4% by weight NaOH solution is made using 47% by weight NaOH solution. The 47% by weight NaOH solution from T-2008 is sent to the inline mixer where it is blended with heated demineralised water from IX Demineralised Water Heater (E-2007).
The demineralised water is pre-filtered using a cartridge-type filter. Furthermore, the 4% by weight NaOH solution is filtered before it is introduced at the top of the ion exchange column. During this phase, the HSS are removed from the resin and the resulting effluent, containing HSS and residual amounts of NaOH, is discharged as waste effluent.

5.3.2.6.5. Excess NaOH Rinse

After the regeneration phase, heated demineralised water is sent again at the top of the ion exchange column to displace the NaOH solution remaining within the resin bed. This dilute NaOH solution that contains HSS is also discharged as waste effluent. After this phase, the column is ready for another IX cycle.
A Programmable Logic Controller (PLC) will control the opening and closing of all the automatic isolation valves, at every step of the batch process.
This batch process will last about 148 minutes and will be repeated at constant intervals up to 9 cycles per day, depending on the level of HSS in the lean amine. This in turn depends on the concentration of SO_2 and NO_2 in the flue gas entering the CO_2 absorber.
The number of daily batches will be set by the operator. As part of the operating process, it is proposed the concentration of HSS will be monitored via a lab testing regime which will be used to provide feedback on the selected frequency of the batch process.

5.3.2.7. Thermal Reclaimer Unit (TRU)

In addition to ionic heat stable salts, amine also accumulates non-ionic amine degradation products over time which must be removed from the solvent by the Thermal Reclaimer Unit (A-2200). The Thermal Reclaimer Unit (TRU) consists of three columns (C-2201, C-2202 and C-2203).

A stream from the lean amine exiting the IX package (A-2100) is fed to the Thermal Reclaimer Unit (TRU) at 30°C and 3 bara. This stream will essentially consist of water, amine, non-ionic degradation products and residual CO_2. The non-ionic degradation products consist of heavy degradation products and light degradation products, both are to be removed from the amine and water. The first TRU column separates the light degradation products, the second and third TRU columns separate heavier degradation products.

On a continuous basis, amine is pumped out of the Reclaimer Feed Vessel (V-2201) and is heated up in a pre-heater (E-2201) from 30°C at 3.5 bara to 110°C using LP condensate. The pre-heated feed is flashed over a control valve and fed into the first thermal reclaimer column (C-2201) at 105°C and 1.23 bara.

The first reclaimer column consists of a rectification section and a stripping section. The feed is introduced at 105°C and 1.23 bara, to the top of stripping section where it is flashed, liquid flows to the stripping packing section whereas vapour flows upward to the rectification section. The rectification section is provided to get a separation between light degradation products and lean amine, and provide a separation between water and light degradation products.

The overhead vapour from the first reclaimer column, which mostly consists of water, is partially condensed in the Overhead Condenser (E-2202) from 105°C to 90°C. The partially condensed two-phase mixture flows to the Overhead Knock-out Vessel (V-2202) where the two phases separate. The reflux, which is mostly water, is pumped by the Thermal Reclaimer Reflux Pump (P-2207A/B) partly to the rectification section of the column on a flow control and partly to the lean amine tank on a level control. The required P-2207A/B pump duty should be confirmed during Detailed Design based upon the final layout. The vapour from Overhead Condenser, consisting of water, CO_2 and light amine components, is sent to the vent header.

The bottom of the first reclaimer column is heated with an insertion type reboiler, heated with MP steam. From the bottom of the first column, amine and heavier degradation products are sent to the second reclaimer column (C-2202).

The second reclaimer column consists of a rectification section and a stripping section. The feed is introduced at 75°C and 0.12 bara, to the top of stripping section where it is flashed, liquid flows to the stripping packing section whereas vapour flows upward to the rectification section. The overhead vapour of this column, which mostly consists of amine, is condensed to 35°C and 0.09 bara and sent to the Overhead Knock-out Vessel (V-2203). The non-condensable vapour, which is mostly air and remaining light degradation products, is sent to the vacuum package (A-2201). A portion of the condensed amine is pumped by Thermal Reclaimer No.2 Reflux Pumps (P-2204A/B) to the column on a flow control as reflux as determined by the required minimum wetting rates and the rest is sent on level control to the Degraded Amine Tank (T-2204) where it is mixed and cooled from 35°C with the degradation products separated from the first thermal reclaimer side stripper column. Diluted residues are periodically disposed of offsite, typically via incineration. The required thermal reclaimer pump duty should be confirmed during Detailed Design, based upon the final layout. Steam sparging is available at the base of the second reclaimer column (C-2202) to reduce viscosity and aid amine reclamation. The Steam Sparger Condensate KO drum (V-2206) receives LP steam from the Condensate Drum (V-4101) and removes any condensate before the steam is injected to the bottom of second reclaimer column. The bottom of the second reclaimer column is heated with MP steam using an insertion type reboiler.

The second reclaimer bottoms residue, which is mostly heavier degradation product, is pumped to Thermal Reclaimer Column No. 3 (C-2203).

The third reclaimer column also consists of a rectification section and a stripping section. The feed is introduced at the top of stripping section at 162°C and 0.12 bara where it is flashed, liquid flows to the stripping packing section whereas vapour flows upward to the rectification section. The overhead vapour of this column is condensed from 157°C to 35°C, and sent to the Overhead Knock-out Vessel (V-2205). The non-condensable vapour, is sent to the Vacuum Package (A-2202). A portion of the condensed amine is pumped by Thermal Reclaimer No.3 Reflux Pumps (P-2206A/B) at 35°C 1.04 bara, to the column on a flow control as reflux as determined by the required minimum wetting rates and the rest is sent on level control to the Lean Amine Tank (T-2001). The required duty of the thermal reclaimer pumps should be confirmed during Detailed Design, based upon the final layout. Steam sparging is available at the base of the third reclaimer column (C-2202) to reduce viscosity and aid amine reclamation.

The bottom of the third reclaimer column is heated with MP steam using an insertion type reboiler. Column pressure is kept at about 0.1 bara by a vacuum pump to operate with a bottom temperature of just under 200°C.

5.3.3. Feed and Product Specifications

The DCC outlet stream sets the specification for the feed to the CO_2 absorber inlet.

There are three distinct cases defined for the DCC outlet conditions. The design case for the CO_2 absorber and stripper corresponds to the maximum operating case, the other cases being the normal operating case and turndown case.

The process conditions and composition of the interface stream (DCC outlet) feeding the CO_2 absorber unit for three cases are as provided previously in Table 5-3.

Important features in feed quality that would impact the CO_2 absorber and stripper performance are:

- SO_2 concentration: Should be as low as possible to avoid heat stable salts build-up in the solvent inventory;
- NO_2 concentration: Should be minimised to avoid increase in amine degradation; and
- Temperature of flue gas: Higher flue gas temperatures reduce capture efficiency and affect the overall water balance in the system.

The objective of the CO_2 absorber and stripper is to capture 90 % of the CO_2 from the flue gas directed to the absorber, to deliver a concentrated stream of CO_2 product for downstream compression. The CO_2 product is cooled to 25°C to minimise the volatile amine degradation component concentration. The CO_2 product specifications are shown in Table 5-8.

Table 5-8: CO_2 from Capture Plant Data

BATTERY LIMIT CONDITIONS	UNITS	VALUE Normal Case	VALUE Turn down Case	VALUE Design Case
Gas Flowrate	kg/h	131,327	90,050	138,136
Temperature	°C	24.1	24.1	24.15

BATTERY LIMIT CONDITIONS	UNITS	VALUE Normal Case	VALUE Turn down Case	VALUE Design Case
Pressure	bara	1.15	1.150	1.150
Composition				
CO_2	mol %	98.0903	98.0903	98.0902
H_2O	mol %	1.9018	1.9018	1.9028
O_2	ppmv	19	19	19
N_2	ppmv	60	60	60
Amines	ppmv	Note 1	Note 1	Note 1
NH_3	ppmv	<0.1	<0.1	<0.1
1. Notes: Details of the proprietary Cansolv solvent amine and other degradation product concentrations are commercially sensitive and are intentionally not described in detail in this document.				

5.3.3.1. Interfaces and Effluents

Refer to Section 5.3.3.3 for all the notes that are specified within the following tables.

5.3.3.2. LP Steam and Condensate

Table 5-9: LP Steam and Condensate

Parameter		IN	OUT
		LP steam	LP condensate
From		OSBL	Reboiler
To		Reboiler	OSBL
		Vapour	Liquid
Temperature	°C	141	40
Pressure	bara	3.2 at battery limit	6.013
Mass Flow (Rated)	kg/h	216,798	216,798
Mass Flow (Normal)	kg/h	180,655	180,655

5.3.3.3. Notes for Subsequent Tables

1. Includes various amine degradation products.
2. Value based on National Carbon Capture Centre (NCCC) piloting data.
3. Calculated from annual make-up requirements. Fresh amine flow does not have to be a continuous flow.
4. Includes Argon.
5. Battery limit pressure increased to accommodate pressure drop across absorber and flue gas re-heater.

6. H_2SO_4 is in salt form.
7. The presented value is conservative since a portion is expected to be captured in the acid wash.
8. Predicted figures are presented for the acid wash effluent composition.
9. Details of the proprietary Cansolv solvent amine and other degradation product concentrations are commercially sensitive and are intentionally not described in detail in this document.

5.3.3.4. Flue Gas and CO_2 Product

Table 5-10: Carbon Capture Plant Flue Gas and CO_2 Product (Design case)

Parameter		IN	OUT	OUT
		Incoming quenched gas	Treated gas from Acid Wash	CO_2 gas from capture plant
	From	Prescrubber	Acid Wash Section	Reflux Accumulator
	To	CO_2 Absorber	Gas-Gas Heat Exchanger (E-1001)	CO_2 Compressor Package
		Vapour	Vapour	Vapour
Temperature	°C	30	30.1	25
Pressure	bara	1.06325 (Note 5)	1.027	1.15
Mole Flow	kgmol/h	86,914	Note 9	Note 9
Mass Flow	kg/h	2,477,736	2,341,405	138.136
Actual Volume Flow (Average)	m^3/h	2,038,370	2,006,0520	Note 9
Component Molar Fraction				
H_2O	mol/mol	0.039	0.041	0.019
Amines	mol/mol	0.000	Note 9 (Note 7)	Note 9 (note 2)
CO_2	mol/mol	0.040	0.0041	0.980
N_2 (Note 4)	mol/mol	0.787	0.817	60 ppmv
O_2		0.133	0.138	19 ppmv
SO_2		1.0 ppmv (dry)	0.000	0.000
NO_2		1.0 ppmv	0.000	0.000

Parameter		IN	OUT	OUT
NH_3	mol/mol	0.7 ppmv	<0.1 ppmv	<0.1 ppmv
NaOH	mol/mol	0.000	0.000	0.000
H_2SO_4	mol/mol	0.000	0.1 ppmv	0.000
Na_2SO_3	mol/mol	0.000	0.000	0.000
Na_2SO_4	mol/mol	0.000	0.000	0.000
NaCOOH	mol/mol	0.000	0.000	0.000
$NaNO_3$	mol/mol	0.000	0.000	0.000
Total	mol/mol	1.000	1.000	1.000

Table 5-11: Fresh and Degraded Amine (Design case)

Parameter		IN	OUT	OUT
		Fresh amine (100% conc.)	Degraded Amine (from TRU 2)	Degraded Amine (from TRU 3)
		OSBL	Degraded Amine Vessel	Degraded Amine Vessel
		Fresh Amine Tank	OSBL	OSBL
		Liquid	Liquid	Liquid
Temperature	°C	10	35	191.5
Pressure	bara	5.3	1.06	1.06
Mole Flow (note 3)	kgmol/h	Note 9	Note 9	Note 9
Mass Flow (note 3)	kg/h	Note 9	242	64.8
Actual Volume Flow (Average) (note 3)	m^3/h	Note 9	0.259	0.09
Component Molar Fraction				
H_2O		0.000	0.989	0.000
Amines	mol/mol	1.000	Note 9	Note 9
CO_2		0.000	0.01	0.000
N_2 (Note 4)		0.000	0.000	0.000
O_2		0.000	0.000	0.000
SO_2		0.000	0.000	0.000
NO_2		0.000	0.000	0.000
NH_3		0.000	0.000	0.000
NaOH		0.000	0.000	0.000
H_2SO_4		0.000	0.000	0.000
Na_2SO_3		0.000	0.000	0.000
Na_2SO_4		0.000	0.000	0.000
NaCOOH		0.000	0.000	0.000
$NaNO_3$		0.000	0.000	0.000
Total		1.000	1.000	1.000

5.3.3.5. Demineralised and Compressor Knockout Water, Caustic and IX Effluent

Table 5-12: Demineralised Water, Compressor Knockout Water, Caustic and IX Effluent (Design case)

Parameter		IN	IN	IN	OUT
		Demineralised water	Process water	47% Caustic soda	IX effluent (averaged over one day)
	From	OSBL	Compressor Knockout	47% Caustic Feed Pump	IX Unit
	To	IX Demineralised Water Heater	Water Wash Section	Caustic Mixer	OSBL
		Liquid	Liquid	Liquid	Liquid
Temperature	ºC	10	28	20	35
Pressure	bara	6.0	1.5	6.0	2.0
Mol Flow	kgmol/h	122	57	2.5	76
Mass Flow	kg/h	2,196	1,021	60	1,365
Actual Volume Flow (Average)	m^3/h	2.2	1.0	0.04	1.4
Actual Volume Flow (Max Instantaneous)	m^3/h	50	-	3.2	54
Component Molar Fraction					
H_2O	mol/mol	1.000	1.000	0.715	0.992
Amines		0.000	0.000	0.000	Note 9
CO_2		0.000	0.000	0.000	0.000
N_2 (Note 4)		0.000	0.000	0.000	0.000
O_2		0.000	0.000	0.000	0.000
SO_2		0.000	0.000	0.000	0.000
NO_2		0.000	0.000	0.000	0.000
NH_3		0.000	0.000	0.000	0.000
NaOH	mol/mol	0.000	0.000	0.285	0.0060
H_2SO_4		0.000	0.000	0.000	0.000

Parameter		IN	IN	IN	OUT
Na_2SO_3		0.000	0.000	0.000	20 ppmm
Na_2SO_4	mol/mol	0.000	0.000	0.000	0.0014
NaCOOH		0.000	0.000	0.000	170 ppmm
$NaNO_3$		0.000	0.000	0.000	400 ppmm
Total	mol/mol	1.000	1.000	1.000	1.000
Component Mass Fraction					
H_2O	mol/mol	1.000	1.000	0.530	0.974
Amines		0.000	0.000	0.000	Note 9
CO_2		0.000	0.000	0.000	0.000
N_2 (Note 4)		0.000	0.000	0.000	0.000
O_2		0.000	0.000	0.000	0.000
SO_2		0.000	0.000	0.000	0.000
NO_2		0.000	0.000	0.000	0.000
NH_3		0.000	0.000	0.000	0.000
NaOH	mol/mol	0.000	0.000	0.470	0.013
H_2SO_4		0.000	0.000	0.000	0.000
Na_2SO_3		0.000	0.000	0.000	140 ppmw
Na_2SO_4	mol/mol	0.000	0.000	0.000	0.011
NaCOOH		0.000	0.000	0.000	620 ppmw
$NaNO_3$	mol/mol	0.000	0.000	0.000	0.0019
Total	mol/mol	1.000	1.000	1.000	1.000

5.3.3.6. Sulphuric Acid, Demineralised Water, Acid Wash Purge

Table 5-13: Sulphuric Acid, Demineralised Water and Acid Wash Purge

Parameter		IN	IN	OUT
		98wt% Sulphuric acid	Demineralised water	Acid Wash (Purge 8)
	From	Concentrated Sulphuric Acid Feed Pumps	OSBL	Acid Wash Section
	To	Acid Wash Section	Acid Wash Section	OSBL
		Liquid	Liquid	Liquid
Temperature	°C	20	10	30.1
Pressure	bara	2.037	6.0	1.03
Mol Flow	kgmol/h	0.3	10	Note 9
Mass Flow	kg/h	26	180	229
Actual Volume Flow (Average)	m^3/h	0.014	0.18	Note 9
Component Molar Fraction				
H_2O	mol/mol	0.10	1.000	0.976
Amines		0.000	0.000	Note 9
CO_2		0.000	0.000	0.000
N_2 (Note 4)		0.000	0.000	0.000
O_2		0.000	0.000	0.000
SO_2		0.000	0.000	0.000
NO_2		0.000	0.000	0.000
NH_3		0.000	0.000	0.000
NaOH		0.000	0.000	0.000
H_2SO_4	mol/mol	0.90	0.000	0.025 (note 6)
Na_2SO_3		0.000	0.000	0.000
Na_2SO_4		0.000	0.000	0.000
NaCOOH		0.000	0.000	0.000
$NaNO_3$		0.000	0.000	0.000
Total	mol/mol	1.000	1.000	1.000

5.3.4. Utility, Catalyst and Chemical Requirements

Table 5-14: Utility and chemical requirements

Utilities	Unit	Value
Electrical Load (Operating Load at Rated Flow rate) (Note 3)	**kW**	**1462**
All Normally Running Pumps in Main Process	kW	1,457

Utilities	Unit	Value
All Thermal Reclaimer Pumps	kW	5
Low Pressure Steam (3.5 bara)	**kg / h**	**180,665**
CO_2 Stripper Reboilers (E-2004)	kg / h	180,665
Demineralised Water (average)	**m^3 / h**	**16.0**
Water Wash Make-up (Note 2)	m^3 / h	16.0
Ion Exchange Unit Daily Average (A-2100)	m^3 / h	16.8
Acid Wash Section CO_2 Absorber	m^3 / h	0.12
Cooling Water (Closed Loop - Supply temperature 20°C, Return Temperature 30°C) (Normal)	**m^3 / h**	**4,174**
CO_2 Lean Amine Cooler (E-2001)	m^3 / h	1,276
Overhead Condensers (E-2005)	m^3 / h	2,698
Thermal Reclaimer Condensers (E-2202, E-2206, E-2208)	m^3 / h	185
Amine IX Cooler (E-2006) - Average	m^3 / h	14.3
Direct Seawater (Supply temperature 15°C, Return Temperature 27.5°C) (Normal)	**m^3 / h**	**4,800**
Water Wash Cooler (E-2003) (normal)	m^3 / h	3,934

Notes:
1) Make-up water is only required when the sea water reaches a maximum temperature of 15°C
2) Utilities for the TRU are based on expected operation). Operation at maximum capacity of 150% will increase consumption
3) Electrical power to the Carbon Capture, Compression & Conditioning Plant is supplied from a dedicated 132 kV transmission grid demand connection.
4) Details of the proprietary Cansolv solvent amine make-up rates are commercially sensitive and are intentionally not described in detail in this document.

5.3.5. Equipment Sizing

The following section describes the main parameters considered in sizing the equipment listed in the Equipment List [23]. This list shows the main equipment dimensions and/or operating conditions.

5.3.5.1. CO_2 Absorber (C-2001)

The CO_2 absorber tower is a rectangular concrete structure (14.5 x 29 x 70 m high) with acid-resistant lining containing four major sections, namely:

- **CO_2 Absorber:** Flue gas enters the CO_2 absorber through the inlet flue gas nozzles which can be rectangular to facilitate proper vapour distribution while minimising the required vapour disengagement space. A bifurcated entry with Schoepentoeter inlet devices is used to minimise vapour disengagement space which reduces the overall tower height and provides additional capital cost savings. This arrangement has been validated during FEED by the packing and internals vendor via a Computational Fluid Dynamic (CFD) evaluation.

- **Water Wash:** The treated flue gas is routed to the water wash section to recover the volatile and entrained amine from flue gas. The packing height includes a margin above the theoretically calculated height. The water wash circulation pumps and water wash cooler will be installed at ground level.
- **Acid Wash:** An acid wash section is installed above the water wash section to recover low molecular weight degradation products, using dilute sulphuric acid. The packing height includes a margin above the theoretically calculated height. The acid wash circulation pumps will be installed at ground level.
- **Absorber Bottom:** The absorber bottom comprises a rich amine collection (chimney) tray and absorber sump. The rich amine collection tray will collect rich amine which trickles down from the bottom packing section and is guided through a dip pipe to the absorber sump. This arrangement will minimise the flue gas carry under and minimise the presence of O_2 in the product CO_2. The absorber sump will contain a raised false bottom, to reduce the inventory of rich amine collected from the absorption packing and pumped to the stripper. This reduced sump volume minimises the rate of degradation of the amine and reduces the inventory of fresh amine to purchase. However, in emergency, it will still be possible to accumulate rich amine above this sump up to the bottom of the inlet flue gas duct.

The CO_2 absorber has been designed with a turn-down capability to 50 % of its design flue gas flowrate. It will also accommodate more than 50 % turndown of the incoming lean amine. The absorber has been designed with a margin of 6 % on the design case on the gas side.

The height and diameter of the absorber will be reassessed during Detailed Design once the final available pressure of the gas is defined and the exact pressure drops in the various tower sections are validated by the internals vendor.

The absorber geometry and absorber design philosophy needs to be optimised during Detailed Design with close co-ordination required between the concrete structure provider and packing and internal vendors during the next phase of the project.

5.3.5.2. CO_2 Stripper (C-2002)

CO_2 desorption occurs in a packed-bed counter-current contacting stripper vessel (6.0 m/5.4 m dia. x 34.6 m high). Intimate gas/liquid contact is achieved with the use of structured packing. This provides the mass transfer surface area required to strip the CO_2 from the circulating solution. The CO_2 rich amine pumped to the stripper is first discharged into a gallery tray. The gallery tray is designed to spread, along the periphery of the stripper, the flow of hot rich amine coming from the Lean/Rich Exchanger (E-2002). The gallery tray provides a zone where the first amount of CO_2 can flash out of the liquid phase without affecting liquid distribution. From the gallery tray, the rich amine flows by gravity to a trough type liquid distributor located underneath. From there, the rich amine is evenly distributed over the packing of the stripping section.

5.3.5.3. CO_2 Stripper Reboilers (E-2004)

A welded plate heat exchanger design is proposed for the CO_2 Stripper Reboilers. During FEED a study was performed to define the optimum steam pressure. For PCCS, the economics favour a low steam pressure to generate maximum power. For this six reboilers are required, with the overall size of E.2004 being 3.166 m x 1.500 m x 2.590 m.

The core of a welded plate heat exchanger is a stack of corrugated heat-transfer plates in stainless steel welded alternately to form channels. The frame of the welded plate heat exchanger consists of four corner beams, top and bottom heads and four side panels with nozzle connections. These components are bolted together and can be quickly taken apart for inspection, service or cleaning.

Welded plate heat exchangers are compact. All the heat transfer area is packed into a smaller footprint than that required for comparable conventional heat exchangers. Welded plate heat exchangers provide many advantages over the typical shell and tube exchangers including:

- Alternately welded plates permit access for inspection, service or cleaning.
- Corrugated plates promote high turbulence which in turn achieves three to five times greater overall heat transfer coefficients than a shell-and-tube heat exchanger and minimise fouling, which makes longer operating periods possible.
- Close temperature approach.
- Compactness as they take up only a fraction of the floor space of a shell-and-tube heat exchanger.

Should fouling occur, it is easy to clean welded plate heat exchangers without removing them from the plant. Cleaning can be done on site by circulating cleaning solutions through the unit. Chemical cleaning is highly effective as a result of the unit's high turbulence and low hold-up volume. Chemical cleaning can also be performed by removing the plate pack and immersing it in a chemical bath.

5.3.5.4. Reflux Accumulators

The Reflux Accumulators (V-2001, V-2202, V-2203, V-2205) have been sized such that the normal liquid level is never higher than the lower third volume of the accumulator to allow sufficient vapour space for disengagement.

However, at start-up and in the absence of CO_2 in the amine fed to the stripper, the reboiler duty may generate much more water vapour which will condense in the stripper condenser and accumulate in the stripper reflux accumulator. In such case, the retention time will drop to about 2 minutes for a short time period, such as start-ups.

A mesh type mist eliminator pad is installed within V-2001 to prevent entrainment of water droplets larger than 10 microns into the gaseous product.

The stripper Reflux Accumulator (V-2001) is also used to supply CO_2 stripper reflux to the IX unit to displace treated amine out of the IX column at the end of the amine recovery step and return it to the lean amine tank. This avoids introducing additional water (for amine displacement) into the system.

5.3.5.5. CO_2 Lean Amine Tank (T-2001)

The lean amine tank is sized to contain the amine inventory required to start and run the Carbon Capture Plant. The total purchased amine inventory is approximately 1,238 m^3 and the tank volume has been sized to accommodate this. However, once amine has been pumped throughout the process and accumulated on the absorber and stripper packings and filled the various vessel sumps, the liquid level in the lean amine tank drops to about 3 m level, an adequate level at which to run the Lean Amine Feed Pumps (P-2005 A/B/C) to prevent cavitation and pump damage.

5.3.5.6. Other Tanks

The Fresh Amine Tank (T-2002) has been sized for approx. 6 months usage of concentrated fresh amine at 100 % concentration.

The Amine Drain Tank (T-2003) is an underground tank containing a sump pump to return collected amine from drains back to the lean amine tank. It has been sized to accommodate the likely maximum drainage load.

The vents on the lean amine tank, the fresh amine tank and the Amine Drain Tank (T-2003), and other tanks in amine service, are all connected to the absorber via a common vent system which operates at a slightly higher pressure than atmospheric pressure. The absorber pressure is into account in the tank design pressure.

The Caustic Soda Tank (T-2008) and the Concentrated Sulphuric Acid Tank (T-2010) have been sized for at least one month's retention, based on their normal consumption rates at the IX unit and in the acid wash section of the absorber. A common design has been used for both these tanks to minimise costs.

The Thermal Reclaimer Feed Tank (V-2201) is a buffer tank collecting treated lean amine from the IX unit (A-2100), when available, and feeding the first Thermal Reclaimer (C-2201) on a continuous basis. It is equipped with level sensors that allow the treated amine to enter the vessel when the level is low and stop the flow upon reaching a pre-defined high level.

The tank's retention time is about 8 hours when the TRU is running at maximum capacity or 10 hours under normal operating conditions. This vessel is vented to the common vent system.

The Degraded Amine Tank (T-2204) has been sized to receive degradation products from the second and third thermal reclaimer columns and maintain the contents continuously mixed to enhance mixing of both sources of degradation products. It has been sized to collect 10 days of waste product when the TRU is running at maximum capacity or 15 days under normal operating conditions. This vessel is vented to the vent system. The tank will be emptied by vacuum truck.

5.3.5.7. Thermal Reclaimer Unit

The Thermal Reclaimer Unit processing rate is based on the design case. The TRU is designed with a 50 % margin on processing rate and packing height with 80 % approach to flooding.
The H&MB for the TRU in normal and turndown condition will be the same as the design case.

The thermal reclaimer unit consists of three thermal reclaimer columns in series. Thermal reclaimer column No.1 operates at low positive pressure, whereas columns No.2 and No.3 operate under vacuum. Each thermal reclaimer column consists of two packed sections with overhead water-cooled condenser and reflux accumulator. The current design assumes that reflux pumps are required. However, the potential to eliminate these pumps should be considered during Detailed Design (e.g. by elevating the condensers to use gravity flow instead).

For all three thermal reclaimers an insertion type reboiler is used, with MP steam as the heating medium.

Spargers are provided to TRU No.2 and No.3 to introduce LP steam as required. These come from a drum that is designed to eliminate the possibility of liquid water being introduced into the hot liquid in the columns and causing violent phase change.

5.3.5.8. Ion Exchange (IX) Unit

The IX unit sizing is based on the amine circulation rate of the design case and the standard size corresponding to this design case is chosen. The IX unit is sized to operate at three cycles per day and is able to operate at maximum of nine cycles per day. The IX unit equipment is sized based on the maximum instantaneous flows required.

5.3.5.9. Process Filters

The amine filter (S-2001) is sized for treating a slip stream of the total lean amine flowrate leaving the lean amine tank. Although the flue gas is expected to be free of dust and the amine not to contain suspended solids, a filter has been added in the FEED design as a precautionary measure.

The Amine Drain Filter (S-2002) has been sized to accommodate the flowrate of the amine drain pump.

5.3.5.10. Process Heater and Heat Exchangers

All heat exchangers, including reboilers and condensers, will be plate type heat exchangers. The exception is the heat exchangers in the thermal reclaimer area which will be shell-and-tube exchangers to minimise pressure drop in systems that operate under vacuum (0.1 bara pressure) and Thermal Reclaimer Preheater (E-2201).

The heat exchangers' surface area have been calculated for "dirty" duty, using a fouling factor (or surface area margin) of at least 10%. Additionally, the frames of all gasketted plate exchangers (heat exchangers not containing gases or vapours) will have to be specified to accommodate at least 20 % more plates than required for their maximum duties, for possible future expansion. Heat exchangers containing gases or vapours have welded plates and cannot be expanded at a future time.

The number of heat exchangers used in parallel for any duty will depend on the duties and surface area required as well as on the maximum size (surface area) of available exchangers at the time of ordering. The expected maximum surface area of a plate and frame exchanger and heat transfer coefficient for individual exchanger has been confirmed by vendors during FEED.

5.3.5.10.1. Summary Heat Exchangers

Heat exchanger duties are calculated based on the maximum design case amine flowrate with additional margin on surface area.

- 10 % equipment margin is added on surface area to the lean amine cooler, reboiler, and overhead condenser.
- 15 % additional equipment margin was added on the water wash cooler.
- 20 % margin is added on the IX unit heat exchangers which include IX reflux heater, IX demineralised water heater and IX amine cooler.
- The thermal reclaimer unit heat exchanger duties are based on the processing rate that includes 50 % margin. An additional 10% equipment margin is added on surface area.

5.3.5.11. Pumps

All pumps will be motor driven and will have installed spares, with the exception of pumps feeding directly batched systems (such as the IX unit) or systems that can be interrupted with little impact on the CO_2 capture system which will not be spared on-line. However, for the latter spares should be kept available in the maintenance store for quick replacement.

Pumps where sparing is required use 2 x 100 % pumps, except in cases where NPSH requirements require smaller pumps.

All main process pumps pumping large flow rate are sized with at least 10 % margin on the design flowrate except the water wash pump which is sized with 20 % margin on the design flowrate.

All small pumps are sized with 20 % margin on the design flowrate. The pump discharge pressures will be those calculated at their operating flowrates, not including the additional flow margin, plus 0.5 bar margin. Additional pressure drop caused by a higher than expected flowrate (including margin) will be mitigated by reducing the pressure drop across control valves in the line and using the pressure margin.

All thermal reclaimer pump discharge flows are sized with a 50 % margin above the design flowrate. No.1 Thermal Reclaimer Liquid Discharge Pump (P-2203) and No.2 Thermal Reclaimer Liquid Discharge Pump (P-2205) are oversized to recirculate fluid back to the sump and promote heat transfer from the electric heater.

5.3.6. 170 m Tall Stack

The existing 170 m tall stack has been inspected during FEED and deemed suitable for the release of lean flue gas to atmosphere by the PCCS project following completion of remediation work as recommended below:

1. Reinstate 26 off M16 hexhead set screws from capping arrangement;
2. Apply protective coating to the entire capping arrangement and top 1 m of Cylinder No. 1;
3. Remove all loose courses of brickwork to the top of Cylinders 2, 3, 4, 5, 6, 7 and 14 and reconstruct;
4. Remove top course of brick from all remaining lining cylinders and pack the newly formed expansion joint with mineral wool blanket;
5. To all cracking >3 mm wide, rake out all loose mortar and install ceramic fibre rope. Rope to be recessed 10 mm from the face of the mortar. Apply temperature resistant silicone seal to the face of all cracks;
6. Reconstruct the 'V; cracks located at the summit of Cylinders 3 and 13;
7. Demolish Cylinder 13 in its entirety and reconstruct using acid resistant brickwork and Furane mortar; and
8. Design and install a replacement Grade 316L stainless steel flashing at the summit of the diffuser.

5.4. Compression and Conditioning Plant (U-3000)

5.4.1. Introduction

The main purpose of the Compression and Conditioning Plant is to deliver CO_2 at the pipeline battery limit meeting the offshore transport system requirements through:

1. Compression of the captured CO_2 to the require pipeline pressure;
2. Oxygen removal in catalytic reactor; and
3. CO_2 dehydration in dehydration package by using molecular sieves.

This document provides process and technology information relevant for use in the subsequent Execute Phase of the project. Equipment items have been specified on FEED datasheets for further development during Detailed Design.

5.4.2. Process Description

The selected CO_2 compression, oxygen removal and dehydration processes are described in this section. Reference should also be made to the associated Process Flow Schemes diagrams [32], [33] and [34].

5.4.2.1. CO_2 Compression Process (First Section)

The compressor is a multi-stage, integrally geared, electric driven machine with Variable Inlet Guide Vanes (VIGVs). The number of compressor stages and the anti-surge loop control depend upon the selected compressor vendor design and associated control system adopted.

The pre-FEED Basis for Design (BfD) assumption was that six compression stages would be required, K-3101/2/3/4/5/6, with anti-surge loop for each stage. However in FEED most vendors have recommended the use of 7-8 stages, typically with 5 stages in the low pressure section and 2-3 stages in the high pressure section with common anti-surge control for each section. This will be considered further in the Detailed Design stage when a preferred compressor vendor will be selected.

For the first three compressor stages, intercoolers are integrated with the separators (using extended surface coolers). Based on received vendor information, the extended surface coolers can be used for process pressures of less than 40 bara. The non-integrated shell and tube heat exchangers are used for higher process pressures in the last three compression stages.

138,315 kg/h of water-saturated CO_2 gas (containing approximately 1.8 mol % water) at 1.13 bara, 24°C flows from the capture plant to the First Compression Stage Knockout Drum (V-3101), where any potential liquid carryover is removed and sent back to the capture unit, together with all liquid water collected from other compression stages and dehydration packages.

CO_2 gas is compressed in the first section to 41.5 bara before it is routed to the Reactor Pre-Heater (E-3001). CO_2 gas at the outlet of each stage is cooled down to around 36°C by using cooling water with inlet temperature of 20°C. This is achieved in 1st/2nd/3rd Compression Stage Integrated Suction Knockout Drums Self-Draining Heat Exchangers (V-3102/3/4). Condensed water in each stage is sent back to the previous stage knockout drum and finally all water is collected in the first Compression Stage Suction Knockout Drum (V-3101) and pumped to the Capture unit (U-2000).

The CO_2 compressor unit design will need to be confirmed and developed further during Detailed Design based on the selected compressor vendor design.

5.4.2.2. Oxygen Removal

The heat of compression is used to provide CO_2 gas from the first section at 150°C for routing to Oxygen Removal Reactor (R-3001).

The hot CO_2, containing around 19 ppmv of oxygen, is mixed with hydrogen supplied by tube trailer and passes to the reactor. The hydrogen reacts with the oxygen to form water via the reaction:

$$2H_2 + O_2 = 2H_2O \quad \Delta Hr = -241.8 \text{ kJ/mole}$$

Thus two moles of water are formed for each mole of oxygen present. Oxygen is removed from the stream to less than 5 ppmv. Thus approximately 30 ppmv of water is expected to be produced. Excess hydrogen is used to ensure that any side reactions which may occur with the small levels of CO_2 impurities present do not prevent the oxygen being reduced to low levels.

A very small temperature rise (negligible for all practical purposes) is experienced across the reactor. Design of injection point shall ensure proper mixing of hydrogen with CO_2 prior to reactor entry.

The reactor temperature is selected to be at least 20°C above the water dewpoint temperature, as liquid water is a catalyst poison. Care must therefore be taken (particularly on start-up and shutdown) to maintain temperatures well in excess of the water dewpoint.

The operational temperature of approximately 150°C will help to avoid formation of $Pd(OH)_2$ which might occur if there are significant amounts of water present in the feed.

It is also important to heat up the catalyst bed with dry gas to 150°C during start-up, which can be done using a connection from the dryer regen system.

5.4.2.3. Dehydration System

The Reactor Outlet Cooler (E-3002), removes the heat generated in fourth stage of CO_2 gas compressor plus the small amount of heat generated in the reaction section. The stream is cooled to 25°C by using cooling water with inlet temperature of 20°C. The temperature approach in E-3002 is minimised (assumed 5°C) in order to reduce the water content of the CO_2 gas.

Condensed water is removed in the CO_2 Dehydration Filter Coalescer (S-3201). The saturated CO_2 gas enters the dehydration unit at approximately 37.8 barg and 24°C.

A molecular sieve dehydration system is used, consisting of two beds, one of which is operational whilst the other is being regenerated. Water-saturated CO_2 gas passes through a packed bed containing molecular sieve pellets. The water vapour from the gas stream is adsorbed onto the molecular sieve and the CO_2 gas leaves the bed containing less than 50 ppmv of water vapour.

After a period of time the molecular sieve bed becomes spent, is taken offline and regenerated by heating the bed using dry hot CO_2 gas. The system has a regeneration loop consisting of a blower, heater (electrical), cooler/condenser and knockout drum.

The hot saturated CO_2 from the regenerating bed is cooled and condensed water is removed. Cooled saturated CO_2 gas is returned to the inlet of the dehydration package to mix with the feed gas. Once the regenerating bed has been dried (indicated by the bed temperature becoming hot) CO_2 gas at ambient temperature is passed through the bed to cool it down before it is put back online.

Dry CO_2 gas from the dehydration unit is filtered in a 100 % duty standby arrangement to remove particulates before sending to the Fifth Compression Stage Knockout Drum (V-3105).

5.4.2.4. CO_2 Compression Process (last two stages)

Dry CO_2 gas from the dehydration unit is compressed from 37.2 bara to 124 bara in the high pressure section.

Dry CO_2 gas is further compressed to 124 bara in the final compression stage where CO_2 is in dense phase and then cooled down below 25°C in the Aftercooler (E-3102). This cooling is important to reduce the likelihood of running ductile fracture occurring in the offshore pipeline. The gas flow rate is measured and analysed in a metering and analyser package, located after the aftercooler, before entering the CO_2 export pipeline.

5.4.3. Design Cases

There are three Heat & Material Balances cases developed for the Conditioning and Compression Plant for the PCCS project: Design (Maximum) case, Normal case and Turndown case. Refer to the FEED design Heat and Material Balances for further details [22].

The GT maximum load case is the governing case and is considered as the design case.

5.4.4. Feed and Product Specifications

There are three distinct cases defined for the Compression and Conditioning Plant (U-3000) inlet and outlet conditions. The design case corresponds to the maximum operating case, the other cases being the normal operating case and turndown case.

The CO_2 product specifications from the carbon capture unit (at the reflux accumulator outlet) feeding U-3000 is provided below.

Table 5-15: CO_2 Specification (at the Compressor Inlet)

Battery Limit Conditions	Units	Value Turn down	Value Normal Case	Value Design Case
Gas Flowrate	kg/h	90,169	131,498	138,136
Temperature	°C	21.1	21.1	21.1
Pressure (Note 1)	bara	1.13	1.13	1.15
Composition:				
CO_2	mol %	97.7796	97.7832	98.090
H_2O	mol %	2.2125	2.2089	1.902
O_2	ppmv	19	19	19
N_2	ppmv	60	60	60
Amines	ppmv	Note 2	Note 2	Note 2
NH_3	ppmv	trace	trace	trace
Notes 1. Pressure at compressor inlet 2. Details of the proprietary Cansolv solvent amine and other degradation product concentrations have been redacted.				

The compressed and conditioned CO_2 product specifications at the outlet of Compression and Conditioning Plant are provided in Table 5-16.

Table 5-16: CO_2 Product Specification (at the entry to the Offshore Pipeline System)

CO_2 Product (to transportation)		Units	Value	Comment
Pressure at battery Limit to Pipeline		bara	121	
Temperature at discharge of aftercooler		°C	25	
Flow Rate		t/h	137	GT 100% Load Max Case
CO_2 Specifications	Design Limit	Comments		

CO_2 Product (to transportation)	Units	Value	Comment
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	FEED design limit was < 1 ppmv, to avoid pitting corrosion of existing 13 Cr stainless well tubing. Redefinition of the limit to 5 ppmv was made after FEED was completed. Please refer to KKD 11.064 - Technology Maturation Plan [6], Section 3.16 for further details.
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		≤ 0.3%	The composition of the CO_2 must be controlled to prevent operation in a region where running ductile fractures can occur.
Noxious components			Toxic contaminants must be controlled to a level that does not significantly affect the hazards posed by CO_2 releases. This covers substances injurious to health and the environment such as nitrogen and sulphur oxides, mercury, aldehydes, particulates and carcinogenic substances that pose a greater hazard than CO_2.
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	Prevent blockage of reservoir. Particulate matter should not create undue handling and disposal hazards due to toxicity, radioactivity etc.

5.4.5. Utility and Chemicals Requirements

Utility and chemical requirements for the Compression and Conditioning Plant (U-3000) are provided in this section.

5.4.5.1. Electricity

Electrical power is needed to drive the compressor, dehydration package heater and the various pumps required by the process. The power requirement is around 18 MW. The FEED design considers sourcing this power from a dedicated demand connection to the 132 kV transmission grid (also used to supply the Carbon Capture Plant). The compressor is the largest single load and is rated at 15 MW.

5.4.5.2. Cooling Water

The compressor package will use cooling water from closed loop cooling system for CO_2 compressor interstage cooling. The data developed during FEED requires to be confirmed with the selected compressor vendor during Detailed Design.

Table 5-17: Cooling water requirement

Equipment	Unit of measure	Flowrate (normal)
Compressor package	kg/h	2,366,571
Reactor outlet cooler E-3002	kg/h	514,610
Dehydration system	kg/h	**156,736**
Total	kg/h	2,251,000

5.4.5.3. Chemicals (Hydrogen)

The FEED design considers the supply of hydrogen by tube trailer.

Table 5-18: Chemicals Requirements

Chemical	Unit of measure	Values
Hydrogen	kg/h	1

5.4.6. Equipment Sizing

The following section describes the main parameters considered in sizing the equipment. This list shows the main equipment dimensions and/or operating conditions.

5.4.6.1. First Compression Stage Suction K.O. Drum (V-3101)

The first compression stage suction knockout drum (V-3101) has a nominal volume of 50 m^3.

A mesh type mist eliminator pad is installed in V-3101 to prevent entrainment of water droplets into the gaseous CO_2 product which is transferred to the compressor.

5.4.6.2. Reactor Outlet Cooler (E-3002)

The reactor outlet cooler will be a shell and tube type heat exchanger. The FEED exchanger surface area has been calculated for "dirty" duty of 6,787 kW and includes an area margin of 10 %.

5.4.6.3. Pumps (P-3001 A/B)

Both pumps will be motor driven and will have an installed spare. All small pumps have been sized in FEED with a 20 % margin on the design flowrate. Pressure drop caused by a higher than expected flowrate (including margin) will be mitigated by reducing the pressure drop across control valves in the line and using the pressure margin.

5.4.6.4. Oxygen Removal Reactor (R-3001)

To meet the required O_2 specification of the sequestered CO_2, it is necessary to condition the captured CO_2 to remove oxygen. The oxygen concentration of the captured CO_2 is estimated to be approximately 19 ppm mol. The oxygen specification of the exported CO_2 was <1 ppmv in the FEED. A single, 1 x 100 % oxygen removal unit is proposed in the FEED design for oxygen removal.

The required catalyst volume is 10 m^3 (based on Johnson Matthey Puraspec 2712), with a reactor diameter defined as 2.1 m which results in a bed height of 2.9 m. The bottom head of the reactor vessel is assumed to be filled with different layers of ceramic balls. The catalyst bed would also be retained by a layer of 19 mm balls. A distance between bottom of catalyst layer and TL of 200 mm was assumed. The proposed FEED reactor design has been confirmed with a catalyst vendor.

Further work to consider the effects of pitting corrosion of the stainless well tubing was done in the Execution Preparation Phase, after FEED was completed. The work has allowed the relaxation of the O_2 content design limit to < 5 ppmv. The impact on the design of the oxygen removal reactor will be assessed in the Project Execute phase. Please refer to KKD 11.064 - Technology Maturation Plan [6], Section 3.16 for further details.

5.4.6.5. Dehydration Package

To meet the water specification in the CO_2 product, the use of molecular sieve dehydration technology is proposed in the FEED design. A filter coalescer is used upstream of the dryer beds to minimise moisture load. Various molecular sieve vendors were contacted during FEED. The FEED design is based on the most onerous conditions from each vendor (highest regeneration flow, largest bed size) to ensure the FEED design is suitable for use with the molecular sieves offered by any future vendor. Final selection of molecular sieve bed type will take place during Detailed Design.

5.4.7. Process Control Requirements

5.4.7.1. General Requirements

A Process Automation System (PAS) and Instrumented Protection System (IPS) shall provide the necessary control, safeguarding (by instruments) and monitoring to ensure that the full CCS chain including the Compression and Conditioning Plant can be operated in a reliable and safe manner. Further details are provided in Section 12.2.

5.4.7.2. Control Strategy for the CO_2 Compression and Conditioning Unit

The main control objectives are:

- To manage variations of CO_2 flow rates from the capture plant;
- To minimise impact of compressor operation on CO_2 stripper operating pressures by maintaining a fixed suction pressure;
- To maintain the compressor discharge pressure below a specific value enabling the routing CO_2 in safe and stable conditions to the export pipeline;
- Safe operation of the CO_2 compressor within its defined operating window;
- Temperature control to oxygen removal reactor; and
- CO_2 product temperature control to pipeline.

The compressor is a multi-stage, integrally geared, electric driven machine with Variable Inlet Guide Vanes (VIGVs). Required turndown flow rates for PCCS operations can be achieved using VIGVs and via the anti-surge loop. The number of stages and the anti-surge loop controls depend upon the compressor vendor design and associated control system adopted.

The suction pressure and the delivery pressure to pipeline are controlled by the VIGVs. Two pressure signals from the first stage suction pressure and inlet pipeline pressure (before the pressure control valve) are sent to a low pressure selector. The lower value is selected to adjust the VIGVs position to control the flow rate through the first compressor stage.

In case of a change in the first stage suction pressure, the compressor VIGVs will be opened/closed to control the flow rate. A pressure control valve is considered at the battery limit to pipeline to maintain a fixed pressure at the compressor discharge. In this way, the pressure profile variation within the compression and conditioning unit is prevented during packing/de-packing cases. The pressure control valve needs to be specified for pressure drop of approximately 2 to 30 bar as the discharge pressure of the control valve can vary between 90 and 120 barg.

An anti-surge control system is proposed to protect the compressor from surge by increasing the flow through the compressor by opening the recycle (kickback) control valve.

The anti-surge system will be provided by the compressor vendor to ensure that operating conditions close to the surge line are avoided (a suitable margin from the surge line will be applied, as recommended by the vendor). As the compressor has multiple stages, flow measurement at the suction of each stage may be required as part of the anti-surge control system.

The outlet temperature of the reaction pre-heater needs to be controlled at 130°C. This temperature control is achieved by managing the LP steam flow rate.

CO_2 product temperature to pipeline needs to be less than 25°C which is achieved by the cooling water flow rate in the Aftercooler (E-3102). No control is required as the cooling water flow rate is normally at the maximum flow and can be manually adjusted.

The level of condensate in each knockout drum is controlled by individual level controllers to prevent liquid carry over to the next stage.

5.4.7.3. Dehydration Package

The dehydration package will have its own PLC and local panel. This PLC is connected to the overall ICCS to enable monitoring of the dehydration unit. The unit contains a regeneration loop which will be automatically controlled via the PLC unit.

The spent molecular sieve bed will be taken out of line routinely for regeneration. This regeneration sequence can be started either after a set time online removing moisture (no moisture breakthrough should occur), or after a moisture analyser indicates that moisture breakthrough has occurred and moisture levels have reached a pre-set value. Alarms and faults will also be sent to the ICCS and ESD systems (as appropriate). The control system will be developed as part of the vendor’s scope during Detailed Design.

5.4.8. Safeguarding Requirements

A safeguarding philosophy has been applied to develop the instrumented relief devices and safeguards which together form the process safeguarding system. The process safeguarding system is designed to prevent deviation of the process outside the equipment design envelope and to reduce associated risks such as loss of containment, toxic release, and fire and/or explosion risks.

A project process safeguarding system was developed during FEED and will be finalised in Detailed Design. The required Safety Integrity Level (SIL) rating of each element of the safeguarding system was determined in the SIL workshops held during FEED and will be confirmed in detailed design. The SIL rating reflects a risk based approach taking probability and consequence of failure into account. It establishes the required reliability of the valve closure system based upon and in turn drives the number of independent shutdown devices, for instance valves, required in series and the maintenance and testing frequency.

Initial indications of key safeguarding criteria that have already been identified include the following:

- Interface between the compression plant and export pipeline to the Goldeneye platform as the design pressure of the pipeline is lower than the compression system (e.g. the high pressure section). A protection system consisting of Emergency Shutdown Valves (ESDs) and associated instrumentation and logic solvers will be in place to protect the pipeline against high pressure, high temperature or high water content outside the pipeline design envelope. This may be classified as a High Integrity Pressure Protection System (HIPPS), referring to a system with a SIL rating of 4 (indicating a probability of failure on demand of 0.0001 to 0,00001), or it may be a lower rated protection system depending upon the detailed design work and the outcome of the SIL review;
- Interface between high pressure and low pressure parts in capture plant and compression;
- Interface with high pressure CO_2 within and downstream of the CO_2 compressor package (e.g. the flow through the various anti-surge recycle valves or the potential backflow). The compression design pressure break point between low pressure and high pressure section is considered at the inlet of the 5th compression stage suction knockout drum;
- Potential release of pressurised CO_2, including release of CO_2 into cooling water system;
- Emergency Shutdown (ESD) of equipment containing high pressure CO_2;
- Compressor surge protection;
- The safeguarding system for the oxygen removal system in the event of off-specification CO_2 product being produced;
- The safeguarding system for the dehydration package in the event of off-specification CO_2 product being produced.

5.5. Tie-Ins

Utility services shall be provided from the existing power station facilities. The new CCCC plant requires piping tie-ins to the following systems:

- Demineralised water;
- Firewater;
- MP steam;
- LP steam;
- Condensate return;
- Cooling water (seawater) supply;
- Cooling water (seawater) return;

- Service water;
- Uncontaminated closed drains;
- Uncontaminated open drains;
- LP steam for start-up; and
- Waste water.

The location and description of the proposed piping tie-ins are shown in the Interface Schedule [10] and the required utility systems are further described in Section 6.

5.6. Layout

5.6.1. Capture Plant

The carbon capture plant and associated equipment will have new equipment, structures, pipe racks, ducting, and foundations; the FEED design considers provision of two new substations with the existing pump house also modified to incorporate a replacement pump. A new underground services system will be installed to serve the new process equipment and paving drainage. New roads and paving will also be provided where required.

The DCC and CO_2 absorption columns are the primary equipment items within the capture plant scope. These are large rectangular plan-section concrete structures to be located to the west of the existing Peterhead Power Station control room.

The main flue gas tie-in will be on the north side of the existing section of duct between HRSG13 and the 90 m repowering stack. The new duct, varying up to approximately 6.1 m x 6.1 m cross section, will be supported on a new structure. From the tie-in, the duct will be routed via a new pipe rack structure to the booster fan K-1001A which will be located between the existing Peterhead Power Station control room and the DCC. The booster fan will be equipped with a recycle line (duct). The main duct then connects to the hot side of the rotary exchanger and into the DCC and then into the absorption column. From the top of the absorption column, the treated gas outlet duct will be routed back to the cold side of the Rotary Heat Exchanger and then tied in to one of the flue gas connections on the east side of the existing 170 m tall stack via a new pipe rack structure running north/south between the auxiliary boiler house and turbine hall.

To maintain economic routing of the duct work, the Rotary Heat Exchanger (E-1001) will be located at an elevation of approximately 25 metres above grade.

There will be a new pipe rack structure running east/west through the DCC and the absorption column area that will accommodate the associated ducting and pipework, with equipment below. At the west end this pipe rack connects to the main process area pipe rack, and at the east end it connects to the pipe rack structure supporting the treated gas outlet duct.

The main process area is located west of the DCC and the absorption column area and to the west of the existing auxiliary boiler house and 170 m tall stack. Excavation of the existing embankment is required to achieve a level site for development.

The existing auxiliary boiler house will be demolished and replaced with a new auxiliary boiler area as indicated on the FEED plot plan.

The layout for the main process area is based on a central north/south pipe rack with equipment located either side. At the south end the pipe rack connects to the DCC and the absorption column area and at the north connects to the Compression and Conditioning Plant area.

The sea water supply and return headers, steam, condensate and utility pipework will be routed through the DCC and the absorption column area pipe rack to enter the main process area at the south end. A pipe bridge shall be provided to carry the pipes from the amine and caustic storage areas to the main process area.

The CO_2 stripper column and associated equipment will be located in a structure to the east of the pipe rack adjacent to the DCC and absorption column. Plate-type heat exchangers are used throughout the process. These have the advantage of compact size and minimum space requirements for maintenance compared to shell and tube exchangers.

The layout of the onshore plant is illustrated on Peterhead Overall CCCC Project Area Plans [35].

5.6.2. Compression and Conditioning Plant

The selected site for the Compressor and Conditioning Plant is within the area that previously contained oil storage tanks, located to the north of the power station site. This location is remote from the existing power station buildings and outside the explosion risk contours for the existing facilities. The site has already been cleared of all redundant tanks and associated equipment, and the soil is reported to be clear of contamination. The site retains its tiered topographical nature but is ready for re-grading and future redevelopment.

All process pipework, utilities, and cable racks will be routed to the Compressor and Conditioning Plant via an elevated pipe rack connecting to the main capture plant area. The pipe rack passes over the existing site access road.

The CO_2 metering skid will be mounted on the outlet of the compressor pipeline in the compression and conditioning plant.

The compressor is housed within a building and is provided with an overhead gantry crane for maintenance. Vehicle access is provided at both ends of the building to facilitate withdrawal/removal of the heat exchanger bundles at one end, and withdrawal/removal of the motor at the other end, utilising the gantry crane.

To the north of the compressor building are the dehydration and oxygen removal packages. To the south of the compressor building is the local electrical substation building.

To the east of the area are the pig launcher, methanol storage tank and pumps. The CO_2 export pipeline will be routed above ground / below ground to the north-east of the area that previously contained the oil storage tanks. The layout of the onshore plant is illustrated in Peterhead Plot Plan Overall CCCC Project Area Plans [35].

6. Utility System Description

6.1. Introduction

This chapter contains a description of the required onshore utilities and premises for utility system designs for the Carbon Capture Plant.

The utility design information provided in following sections is based on current available process data. During Detailed Design, the EPC Contractor shall verify all provided utility data for consistency with latest process information and battery limit data and adjust the utility design capacities and/or equipment design accordingly.

For further process information, reference should be made to the associated Utility Flow Schemes [36], [37], [38], [39] and [40]. Other relevant information can be found on the Equipment Summary List [23] and Utility Requirement Report [41].

A project process safeguarding system was developed during FEED to prevent deviation of the process outside the equipment design envelope and to reduce associated risks such as loss of containment, toxic release, and fire and/or explosion risks. This will be revisited and finalised during Detailed Design. Refer to the Cause and Effect Diagram [42], for a high level summary of the key safeguarding issues identified during FEED.

6.2. Steam System (U-4100)

6.2.1. Introduction

The purpose of the LP steam and condensate system is to provide the CCP's heat requirements for the CO_2 Stripper Reboiler units. Steam is supplied by the Power Plant. After heat recovery in two process heat exchangers the condensate is sub-cooled before being returned to the Power Plant. Refer to Section 4 for further information on the Power Plant element of the PCCS Project.

In addition, MP steam from the Power Plant auxiliary boiler is used as the heating medium in the amine TRUs, with condensate being returned to the auxiliary boilers. The CO_2 vaporiser, located in the conditioning and compression plant area, is an occasional user of MP steam.

6.2.2. Process Description

LP steam is diverted from the inlet to the low pressure cylinder of ST20 and de-superheated within the Power Plant to reach the battery limit conditions of 3.2 bara and saturation temperature. The steam at the battery limit will have a small amount of superheat which will minimise the formation of condensate in the steam pipe during operation. Steam warming drains, vents and steam traps will be provided to ensure any condensate formation, particularly at start-up, is safely collected and removed to avoid erosion other damage to the system components.

In the CCCC (Carbon, Capture, Compression and Conditioning) plant process steam is used to supply heat to the CO_2 Stripper Reboiler (E-2004 A/B/C/D/E/F).

The condensate is discharged to a Condensate Drum (V-4101) and pumped back to the condenser of the Power Plant Steam Turbine (ST20).

The Power Plant battery limit conditions for condensate are 5 barg and 40°C. The condensate is analysed and in the event of contamination from amine it can be rerouted to the waste wash water tank. Normally the condensate is routed through the existing condensate polisher in the power station scope.

For the MP steam system, steam is condensed in each TRU and collects in a condensate drum and is pumped back to the MP condensate return header by the MP condensate pumps.

6.2.3. Selected Process Configuration

The risk of leakage into the condensate system has been assessed as low, due to the nature of the heat exchangers and the fact that the steam and condensate will operate at a higher pressure than the process (so any leakage will be into the process side). However in the event of contamination there is the facility to route the contaminated condensate to the waste wash water tank.

6.2.4. Design Cases, Design Margins and Turn Down

The steam system is designed for the maximum (design) case plus 10 % margin. To calculate design flow a design margin of 10 % is added to the maximum flow of the steam consumers.

The duty of the condensate cooler is based on the total steam and condensate inclusive of the 10 % margin, to be able to cool down the condensate to 40°C also in case both heat recovery exchangers are not in operation.

MP steam was chosen as the heating medium for the thermal reclaimers rather than electric heating, because of better licensor operating experience and lower propensity for causing thermal degradation.

6.2.5. Steam System Design Integration

For process heating in the CCP, selection of a higher steam pressure allows for a higher condensing temperature and a higher Log Mean Temperature Difference (LMTD) in the stripper reboilers. This results in a reduced reboiler heating surface area requirement and is reflected in a reduction in the capital cost of the reboilers. However, selection of a higher steam pressure in the Carbon Capture Plant means that steam does less work in the steam turbine before it is supplied to the CCP, with a corresponding reduction in power output from the steam turbine generator, resulting in reduced revenues.

Process optimisation study work was carried out during FEED to identify the LP steam conditions that result in the most economical solution overall, by considering the variation in capital cost of the reboilers with the variation in income available from electricity generation. The optimum LP steam condition for the Reboiler (E-2004 A/B/C/D/E/F) was determined as steam of 3.2 bara at saturation temperature (135.8°C).

The Thermal Reclaimer Units (TRUs) in the Carbon Capture Plant will operate at higher temperatures than the stripper reboilers. The study work showed that supplying the heat required by the TRUs by diverting steam from the steam turbine generator would result in a significant reduction in power output. The MP steam required by the TRUs would be more economically supplied by using steam that has not been diverted from the steam turbine. MP steam was also selected as the heating medium for the CO_2 vaporiser unit that is located in the conditioning and compression plant area. When required, the vaporiser will be operated when the TRUs are shut down, such that the vaporiser's demand does not create and additional capacity requirement upon the MP steam supply system.

Additionally, the existing auxiliary boiler installation on the power plant was identified for demolition to provide room on site for the Carbon Capture Plant, such that a replacement steam supply that meets the power plant's demand for auxiliary steam would be required.

The optimum solution, as described in the FEED documentation, is for installation of a new auxiliary boiler system that will meet the power plant's needs for auxiliary steam and provide MP steam to the CCCC Plant. A common auxiliary boiler system solution that serves both the power plant and the CCCC plant was considered beneficial in several ways, including capital cost, maintenance costs and thermal performance, when compared to having dedicated auxiliary boiler systems for each facility.

6.2.6. Capacity and Flexibility

Table 6-1 below shows the maximum heat demand from the steam consumers.

Table 6-1: Steam System Demand and Process Temperature Levels

Heat Exchanger	Equipment Name	Duty	Process temperatures		Flow Rate	
Tag		**(kW)**	**t1 (˚C)**	**t2 (˚C)**	**[kg/h]**	**[t/h]**
			LP steam users			
E-2004 A/B/C/D/E/F	CO_2 Stripper Reboilers	111,002	111.5	119	180,665	180.7
SPI-2701	TRU steam spargers	n/a	n/a	n/a	200	0.2
Total	**Incl. 10% design margin**	**133,138**			**216,998**	**217.0**
			MP steam users			
Thermal Reclaimer Reboilers	**Incl. 20% design margin**	**2,593**			**4,972**	**5.0**
E-4705 (Note1)	CO_2 Vaporiser	2,100	-46	-46	3,947	4.0
Note1: The design of the MP Steam is on the basis that the consumption of the CO_2 vaporiser is not co-incident with the steam consumption of the thermal reclaimer reboilers.						

Table 6-2 below shows the maximum heat demand from the heat recovery consumers and the condensate cooler.

Table 6-2: Heat Recovery Demand and Process Temperature Levels

Heat Exchanger	Equipment Name	Duty	Process temperatures		Flow rate	
Tag		**(kW)**	**t1 (˚C)**	**t2 (˚C)**	**[kg/h]**	**[t/h]**
E-2007	IX Demineralised water heater	1,452	5	30	14438	14.4
E-2201	TR 1 Pre-Heater	298	25	35	3832	4
E-4102A/B	Condensate cooler	21,840	20	30	216,798	217
Total		21,840			216,798	217

6.2.7. Process Control Requirements

A back pressure controller is used to hold pressure in the system and prevent vacuum conditions that could cause evolution of vapour. The flow balance between individual users is controlled by manual valves.

6.3. Sea Water Cooling System

6.3.1. Introduction

The Power Plant operates a once-through Sea Water Cooling (SWC) system that will be modified to supply coolant to the CCCC plant. The power plant's sea water cooling system includes filtration at the intake station and has hypochlorite injection for microbiological control. Four sea water pumps are installed and these are principally used to cool the steam turbine condensers, however less than 50 % of the system capacity is currently being used by the power plant.

The power plant's cooling system will be extended to supply the CCCC plant. Three cooling water booster pumps (3 x 50 %) are proposed for installation within the power plant area, taking their suction from downstream of the existing sea water pumps and treatment equipment, sending cooling water to the CCCC plant.

Within CCCC plant scope, the cooling system consists of the sea water cooling loop, including back wash filters, and an indirect closed cooling heat exchanger and two process users.

6.3.2. Process Description

The average pressure (depending on tide) in the SWC system is 0.6 barg. Dedicated new cooling water booster pumps (3 x 50 %), which are included within the power plant scope, lift the head to 3.3 barg at the battery limit.

The CCCC plant sea water system consists of online automatic back wash filters (S-4201 A/B/C) to allow operation without interruption through the cooling circuit. In addition, the sea water cooling system includes the following coolers:

- Closed Loop Cooler (E-4201 A/B/C/D);
- DCC Cooler (E-1002);
- Water Wash Cooler (E-2003).

The Closed Loop Cooler (E-4201 A/B/C/D) cools the closed loop cooling water, which provides cooling to all others consumers of the Carbon Capture Plant (see Section 6.4).

Seawater from the heat exchangers is collected prior to being discharged. The discharge line is tied-in at the outfall line from SSE. The pressure at the battery limit is 1.8 barg.

6.3.3. Design Cases, Design Margins and Turn Down

The determining case for designing the total cooling water duty and flow of the sea water system shall be the maximum sea water temperature of 15°C for the design case of the CCCC plant (maximum throughput). On top of this, the FEED design cooling duty includes 5 % contingency and 5 % hydraulic margin.

The return temperature is limited to 27.5°C to comply with local environmental regulations.

At the closed loop heat exchangers a design margin on 10 % at the surface area has been applied in the developed FEED design.

6.3.4. Feed and Product Specifications

Sea water intake and adequate filtering/treatment (hypochlorite injection) to avoid biological fouling is in the Power Plant scope. To avoid fouling of the plate and frame heat exchangers automatic back wash filters are applied in the CCCC scope.

6.3.4.1. Sea Water Temperature

Surface seawater temperature varies by season. The temperature approach of the closed loop cooler heat exchanger is assumed to be 5°C. The seawater supply temperatures are shown below.

Table 6-3: Cooling water supply temperatures

	Minimum	Average	Maximum
Seawater supply temperature (°C) (SWS)	5	10	15
Closed cooling water supply temperature (°C)	10	15	20

6.3.4.2. Sea Water Quality

Sea water specifications and quality information is provided in Table 6-4 below.

Table 6-4: Sea Water Quality at Peterhead Power Station

Common Name	Symbol	Unit	Value
Chloride	Cl	mg/l (ppm)	19,350
Sodium	Na	mg/l (ppm)	10,750
Sulphate	SO_4	mg/l (ppm)	2,700
Magnesium	Mg	mg/l (ppm)	1,290
Calcium	Ca	mg/l (ppm)	410
Potassium	K	mg/l (ppm)	380
Bicarbonate	HCO_3	mg/l (ppm)	140
Bromide	Br	mg/l (ppm)	65
Strontium	Sr	mg/l (ppm)	13
Aluminium	Al	mg/l (ppm)	1.9
Silicon	Si	mg/l (ppm)	1.1
Fluoride	F	mg/l (ppm)	0.8
Nitrate	NO_3	mg/l (ppm)	0.8
Boron	B	mg/l (ppm)	0.4
Barium	Ba	mg/l (ppm)	0.2
Iron	Fe	mg/l (ppm)	0.1
Manganese	Mn	mg/l (ppm)	0.1
Copper	Cu	mg/l (ppm)	0.1
Lithium	Li	mg/l (ppm)	0.1

Phosphorous	P	mg/l (ppm)	0.06
Iodide	I	mg/l (ppm)	0.04
Silver	Ag	mg/l (ppm)	0.02
Arsenic	As	mg/l (ppm)	< 0.01
Nitrate	NO_2	mg/l (ppm)	< 0.01
Zinc	Zn	mg/l (ppm)	< 0.01
Total (excluding H_2O)		mg/l (ppm)	35,000

6.3.5. Capacity and Flexibility

Table 6-5 below shows the maximum heat demand from the consumers. The design case is preliminary defined based on the maximum demand of the individual consumers.

Table 6-5: Sea Water Cooling Demand and Temperature Levels

Heat Exchanger	Equipment Name	Duty	Process temperatures		Sea water Flow rate
Tag		**(kW)**	**t1 (˚C)**	**t2 (˚C)**	**[te/h]**
E-1002 A/B	DCC cooler	70,900	39.3	20	5,116
E-2003	Water wash cooler	56,875	41.5	20	4,800
E-4201 A/B/C/D	Closed Loop cooler	109,500	30	20	9,862
Total		237,275			19,778

6.3.6. Interfaces and Effluents

Battery limit conditions are detailed in the Peterhead CCS (Onshore) Interface Schedule [10]. No effluents are emitted from the sea water system.

6.4. Closed Loop Cooling System

6.4.1. Introduction

All process cooling (except the DCC cooler and water wash cooler) and utilities cooling will be provided by the closed cooling water loop. The cooling water is cooled against seawater in heat exchangers and distributed to the process or utilities coolers. The seawater cooling is a once through loop. The sea water cooling system is described in Section 6.3.

6.4.2. Process Description

The closed loop cooling water is supplied to the users by 2 x 100 % circulation pumps (P-4251 A/B). The returning cooling water at higher temperature is cooled through Closed Loop Cooler (E-4201 A/B/C/D) to the original supply temperature and then routed to an expansion vessel

(V-4251) before re-circulating back to the users. The Expansion Vessel (V-4251) is a horizontal atmospheric vessel.

The closed loop cooling water system uses demineralised or low-conductivity water conditioned with corrosion inhibition chemicals as cooling water. After the initial fill up, demineralised water make-up requirements are intermittent as small losses are envisaged during normal operation. Chemical dosing is required for water chemistry adjustment (pH, corrosion inhibitor, and biocide).

A side stream filtering (indicative capacity of 2 % of the total flow) for the closed loop cooling water circuits will be installed to trap any particles such as rust.

In wintertime ambient temperatures below freezing point can occur. Circulation should be maintained to prevent freezing.

6.4.3. Technology Selected

The closed loop cooler shall be of the plate and frame type to reach the lowest process temperature of approx. 30°C in the top of the absorber. The circulation pump is assumed to be of the centrifugal type in the developed FEED design.

6.4.4. Design Cases, Design Margins and Turn Down

The determining case for designing the cooling duty of the U-4250 closed loop cooling system was identified to be the maximum sea water temperature of 15°C at the inlet of the Closed Loop Cooler (E-4201 A/B/C/D). The temperature approach of the closed loop cooler heat exchangers in FEED was 5°C. The FEED design cooling duty included a 10 % design margin.

6.4.5. Feed and Product Specifications

The initial filling and make-up water used in closed loop cooling water system U-4250 is town's water with demineralised water used for top-up. The circulating cooling water shall also maintain the required chemical concentrations in the system to prevent corrosion and bio-fouling. The control range of cooling water quality depends on the selected chemical treatment program. To maintain the quality of the cooling water in the system, manual sampling, laboratory analysis, chemical make-up and control range shall be reviewed further during Detailed Design in accordance with the chemical supplier's instruction.

6.4.6. Capacity and Flexibility

The FEED closed loop cooling water system capacity has taken into account the maximum flow to all closed loop coolers.

Table 6-6: Closed Loop Cooling Demand and Process Temperature Levels

Heat Exchanger	Equipment Name	Duty	Process temperatures		Flow rate
Tag		(kW)	t1 (°C)	t2 (°C)	[m^3/h]
E-2006	IX Lean Amine Cooler	173	40.5	35	14.9
E-2001	CO_2 Lean Amine Cooler	15,432	40.5	30	1,330

Heat Exchanger	Equipment Name	Duty	Process temperatures		Flow rate
Tag		(kW)	t1 (°C)	t2 (°C)	[m^3/h]
E-2202	Thermal Reclaimer Condenser 1	1,688	105	90	146
E-2206	Thermal Reclaimer Condenser 2	171	67.1	35	15
E-2208	Thermal Reclaimer Condenser 3	380	160	35	33
A-3100	CO_2 Compression Cooling (package)				2,366
E-3002	Reactor Outlet Cooler	6,170	134	25	514
E-3203	Regeneration Gas Dehydration Unit	1,820	256	30	157
E-2005 A/B	Overhead Condenser	32,5649	94	25	2,817
E-4102 A/B	Condensate Cooler	18,200	126	40	1,569
A-4701A/B	Instrument Air Compressor	40			3.4
Total		97,530			8,320

6.4.7. Process control requirements

The condensate level in the Flash Vessel (V-4101) is controlled by a level controller which modulates a control valve in the discharge of the Condensate Pump (P-4101).

To meet the battery limit conditions and the temperature requirements of the condensate polishing package, the condensate has to be cooled down to approximately 40°C.

The condensate temperature in the condensate return line is therefore controlled by a control valve at the inlet of the Condensate Cooler (E-4102 A/B). A pressure differential controller controls the pressure drop over the heat recovery heat exchangers and the condensate cooler.

6.4.8. Interfaces and effluents

Battery limit conditions are detailed in the Peterhead CCS (Onshore) Interface Schedule [10]. No effluents are emitted in the closed loop cooling system.

6.5. Towns Water and Potable Water Systems

6.5.1. Introduction

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.

6.5.2. Process Description

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 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.

6.5.3. Process Control Requirements

No relevant process control is foreseen for the potable water system at this stage.

6.5.4. Interfaces and Effluents

Battery limit conditions are detailed in the Peterhead CCS (Onshore) Interface Schedule [10]. No effluents are emitted from the water systems.

6.6. Demineralised Water System

6.6.1. Introduction

A tie-in is made at the Power Plant demineralised water system for supply of demineralised water.

6.6.2. Process Description

Demineralised water usage is normally intermittent and used on an as required basis for make-up, washing and dilution purposes. In the CCCC plant, demineralised water will be supplied to the following units:

- Water Wash (C-2001);
- Acid Wash (C-2001);
- To Reflux Accumulator (V-2001);

In the Ion Exchange cycle, demineralised water is used for two purposes:

- Diluting the concentrated caustic to 4 % for use in the regeneration step of the ion exchange cycle
- Washing the ion exchange resin bed after the caustic regeneration step

Demineralised water is also used for periodic make-up of the closed loop cooling water systems (U-4250). Utilisation for this purpose is marginal.

6.6.3. Design Cases, Design Margins and Turn Down

The FEED system design is based on peak flows plus a design margin of 10%.

6.6.4. Feed and Product Specifications

The demineralised water will be supplied by the power plant. The demineralised water quality is required to meet the following specification:

Table 6-7: Minimum Quality requirements for Demineralised Water

Parameter	Units	Specification
Conductivity at 25°C:	µS/cm	<5
Total CO_2	mg CO_2 /kg	<0.1
Hardness ($CaCO_3$)	mg $CaCO_3$/kg	< 0.1
Total iron	mg Fe/kg	If raw water is drinking water, drinking water criteria are sufficient.
Total Copper	mg Cu/kg	If raw water is drinking water, drinking water criteria are sufficient.
Permanganate	mg $KMnO_4$/kg	See comments on Fe
Chloride ions	mg Cl/kg	< 0.1
Silica	mg SiO_2/kg	< 0.1
Oxygen	mg O_2/kg	1
Corrosion Inhibitor		No CI allowed

6.6.5. Capacity and flexibility

The current estimated average demand is 17 m^3/h.

Table 6-8: Overview Demineralised Water Consumers

Demineralised water users list		Design case [kg/h]	Remarks
C-2201	Thermal Reclaimer Column No. 1	1,000	Normally no flow
C-2202	Thermal Reclaimer Column No. 2	130	Normally no flow
C-2203	Thermal Reclaimer Column No. 3	2,100	Normally no flow
T-2001	Lean Amine Tank	20,000	Normally no flow
T-2002	Fresh Amine Tank	20,000	Normally no flow

Demineralised water users list		Design case [kg/h]	Remarks
T-2003	Amine Drain Tank	5,000	Normally no flow
C-2001	CO_2 Absorber water wash loop	14,958	Normally no flow
C-2001	Acid Water Wash loop	180	Normal flow 165 kg/h
E-2007	Demineralised Water Heater	54,000	Normal flow 16,800 kg/h – Peak flow is for a 20 minute duration when the normal source (CO_2 Stripper Overheads) is not available
P-2208A/B	Thermal Reclaimer Unit Bottoms Pumps	1,000	Normally no flow
	Peak Design Flow	54,000	

6.6.6. Process Control Requirements

No relevant process control is foreseen for the demineralised water system at this stage.

6.6.7. Interfaces and Effluents

Battery limit conditions are detailed in the Peterhead CCS (Onshore) Interface Schedule [10]. No effluents are emitted from the demineralised water system.

6.7. Instrument Air System (U-4700)

6.7.1. Introduction

Instrument Air is supplied to all pneumatically operated instruments and air purges where required. Other users may be added during further engineering.

Air in distribution piping is segregated into two headers as it leaves the Utility area:

- Instrument Air;
- Plant (Tool) Air.

6.7.2. Process Description

Instrument Air is supplied to all pneumatically operated instruments and air purges where required. Other users include compressor seal systems and analysers.

A non-essential branch is taken from instrument air header to provide tool air to utility stations in the process area. This branch shall be load shed if the instrument air header pressure drops below acceptable levels.

The instrument air system for the CCCC plant includes:

- 2 x 100 % capacity electric driven screw type air compressor packages with inter and after coolers;
- 2 x 100 % regenerative electric heater instrument air dryer package;

- 1 x 100 % capacity headers, with full bore ball valves and blind flanges at one side;
- 1 x 100 % instrument air buffer vessels; and
- A load shedding system.

6.7.3. Technology Selected

In view of the limited size of the instrument air system, screw type compressors have been assumed in FEED. Final equipment selection will be made during Detailed Design based on minimum through life costs.

6.7.4. Design Cases, Design Margins and Turn Down

The FEED estimate for instrument air flow includes a 125 % design margin to account for preliminary figures used for vendor packages. For other users (analysers, valves, instruments) the peak flow is taken as 100 % normal.

6.7.5. Capacity and Flexibility

During Detailed Design the consumer and load lists shall be further developed using more accurate demand data which will be used as a basis for detailed equipment sizing. The FEED design considers that the instrument air demand will be approximately 963 Nm^3/h for the CCCC plant.

6.7.6. Effluents

No effluents are emitted from the instrument air system.

6.8. Waste Water Treatment System (U-4800)

6.8.1. Introduction

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 developed in FEED is presently under review and will be considered further in Detailed Design.

6.8.2. Process Description

The basic philosophy involves conversion of amines to ammonia and then further conversion of ammonia to nitrogen using nitrification then de-nitrification processes.

6.8.2.1. Effluent Stream Screening

All incoming effluent streams will be screened for solids prior to the balance tanks. The acid wash effluent will initially be collected in a dedicated buffer tank which will have the facility for to connect to road tanker if required. From this tank it will be pumped forward at a controlled rate to the main effluent balancing tank which will have around a one-day storage capacity. Here it will be mixed and balanced with the other effluent streams. A divert tank is provided for storage of off-specification effluent which cannot be treated immediately. Effluent from the divert tank can then be returned to the balance tank under controlled conditions

The balance tank effluent is pumped forward to two biological treatment stages.

6.8.2.2. Biological Treatment Stage One

The first biological treatment stage is required to convert the amines to ammonia. The biological reactor will also treat Total Organic Carbon (TOC), Biological Oxygen Demand (BOD) and Chemical Oxygen Demand (COD) in the effluent.

This stage involves three processes; an anoxic tank, ammonification Moving Bed Bioreactor (MBBR) tank with 2.3 days hydraulic retention (including plastic media) and a clarifier. The purpose of this stage is to ensure all amines are converted to ammonia together with partial removal of ammonia and COD.

The MBBR system consists of an activated sludge aeration system where the sludge is collected on recycled plastic media. The media has a large surface area for optimal contact between water, air and bacteria. The bacteria/activated sludge grows on the internal surface of the media and breaks down the organic matter from the waste water. The aeration system keeps the media with the activated sludge in motion.

The clarifier provides settlement and control of the return of concentrated micro-organisms to the aeration tank, which is vital to the MBBR process.

6.8.2.3. Biological Treatment Stage Two

Stage two of the biological treatment involves nitrification and de-nitrification (DN) treatment using anoxic-aeration-post de-nitrification steps and a membrane bioreactor. The second biological stage will treat any residual amines, as well as TOC, BOD and COD not treated in the first stage of the process. The purpose of this stage is to achieve nitrogen removal from amines and ammonia. The second stage includes an anoxic tank, aeration tank, a second anoxic tank and a Membrane Bio Reactor.

The membrane bioreactor (MBR) system (with Ultra Filtration membranes), located downstream of the biological treatment stages, will ensure the quality of treated wastewater required for discharge.

The Membrane Bioreactor is a combination of an activated sludge process and membrane filtration and is proposed for reduction of ammonia in the waste water. Air is blown through the waste water in the aeration tank, allowing organisms to develop a biological floc which reduces the organic content of the effluent. A high rate of solids is maintained in the aeration tank in the MBR process and membrane filtration and this ensures consistency in the quality of water it produces. This aerated water with high solids is then passed through ultrafiltration membranes for solids removal. Part of the residual material, the sludge, is returned to the head of the aeration system to mix with the new waste water entering the tank.

6.8.2.4. Odour Control

All waste water tanks will be covered and an extraction system will be provided. The extraction system will then transfer any emissions to a scrubber system.

6.8.2.5. Sludge Dewatering

The biological sludge generated will be stored in a sludge tank. The sludge from the sludge tank will be dewatered using a centrifuge prior to being trucked offsite for disposal locally as non-toxic waste.

6.8.2.6. Observation Basin

The observation basin will receive the following effluents:

- Power plant boiler make-up plant ion-exchange regeneration stream;
- Power plant treated effluent derived from the effluent treatment plant final discharge.

The amine wash water will initially be held in tank T-4803 (1000 m^3 capacity). From this tank it will then be pumped forward at a controlled rate to the observation basin. The observation basin will have a retention time of three hours. The observation basin will be provided with mixing to ensure the effluent streams are fully blended prior to discharge.

6.8.3. Design Cases, Design Margins and Turn Down

6.8.3.1. DCC Effluent

A design margin of 10% was applied on the designed DCC effluent flow in FEED to take into account possible fluctuations in flow rate.

6.8.4. Feed and Product Specifications

6.8.4.1. Feed Specification

The feed to the waste water system consists of the following streams:

1. **DCC Condensate Effluent**

Table 6-9: Composition and of the DCC Condensate Effluent

Parameters	Unit	Value		
		Design case	Normal case	Turndown case
CO_2	mg/L	317	317	323

Parameters	Unit	Value		
O_2	mg/L	0	0	0
NH_3	mg/L	111	106	112
N_2	mg/L	16	16	11
H_2O	mg/L	997,219	997,229	993,408
Temperature	°C	20	20	20
Pressure	bara	1.113	1.113	1.113
Flowrate	kg/hr	59,344	59,983	36,995

2. Acid Wash Effluent

Table 6-10: Flowrate and Indicative Composition of the AW Effluent

Parameters	Unit	Value	
		Design case	Normal case
Amines (note 1)	mg/L	101,988	97,903
NH_4/NH_3	mg/L	3,438	4,602
Na	mg/L		-
H_2SO_3	mg/L		-
H_2SO_4	mg/L	111,166	113,194
H_2O	mg/L	785,677	786,611
TOC	mg/L	57,906	54,617
TKN (Kjeldahl Nitrogen)	mg/L	28,921	28,540
COD	mg/L	226,036	214,658
BOD	mg/L	135,621	128,795
Temperature	C	29.8	30.3
Pressure	bara	1.028	1.028
Flowrate	kg/hr	404	229
pH	-	3	3

1. Details of the Cansolv solvent amine and other degradation product concentrations have been redacted.

Table 6-11: Ion Exchange Unit Operation

Parameter	Units	Value	Notes
Flow Rate			Note: Operation is batch-wise
Daily Average	kg/hr	1,820	

Parameter	Units	Value	Notes
Peak	m^3/hr	54	
Average Composition			
NaOH	mol%	0.6	
H_2O	mol%	99.2	
Sodium Salts			e.g. Sodium Formate / Sodium Nitrate
Amines	ppmv	17	average
Temperature	°C	30	
Pressure	bara	3.0	

3. SSE Water Treatment Plant – CPP Regeneration Effluent

Table 6-12: Flowrate and Composition of SSE Water Treatment Plant – CPP Regeneration Effluent

Parameter	Unit	Value	Notes
Flowrate	m^3/h	1.21	29 m^3/day
Ammonia	mg/l	366	
COD (assumed)	mg/l	0	
BOD (assumed)	mg/l	0	
pH (assumed)		8.8	
Total Dissolved Solids (assumed)	mg/l	4,637	
Total Suspended Solids (assumed)	mg/l	100	

4. SSE Water Treatment Plant – Regeneration Effluent of Boiler Make-Up Water Treatment Plant Ion Exchanger

Table 6-13: Flowrate and Composition of SSE Water Treatment Plant – Regeneration Effluent of Boiler Make-up Water Treatment Plant ION Exchanger

Parameter	Unit	Value	Notes
Flowrate	m^3/hr	10	238 m^3/day
Ammonia	mg/l	0	
COD (assumed)	mg/l	0	
BOD (assumed)	mg/l	0	
pH (assumed)		8.8	

Total Dissolved Solids (assumed)	mg/l	8,559	
Total Suspended Solids (assumed)	mg/l	100	

5. Ion Exchanger Effluent

Table 6-14: Flowrate and Composition of ION Exchanger Effluent

Parameter	Unit	Value	Notes
Flowrate	m^3/hr	1.82	44 m^3/day
Ammonia	mg/l	0	
COD (assumed)	mg/l	0	
BOD (assumed)	mg/l	0	
Sodium Sulphate (Na_2SO_4)	mg/l	11,200	
Sodium Hydroxide	mg/l	13,500	
pH		8	
Total Dissolved Solids (assumed)	mg/l	26,900	
Total Suspended Solids (assumed)	mg/l	0	
Trace Amines	ppmv	17	
Temperature	°C	30	
Pressure	bara	3	

6. Waste Wash Water – During Commissioning

Table 6-15: Flowrate and Composition of Commissioning Waste Wash Water

Parameter	Value
Volume	1,000 m^3
Frequency	Once in plant life
Composition	0.50 wt% Na_2CO_3 0.05 wt% detergent – Paratene D-740

7. Waste Wash Water – During Plant Maintenance

Table 6-16: Flowrate and Composition of Maintenance Waste Wash Water

Parameter	Value
Volume	1,000 m^3
Frequency	Once every four years
Composition	maximum 0.1 wt% total amine

8. Miscellaneous Other Streams

In addition to the main effluent streams identified, there will be other miscellaneous discharges from spillages and drain vessel discharges. The flow rate of such streams is taken to be 0.01 m^3 per day. The composition of such streams is to be taken as 0.1 wt% total amine.

Tank T-2004 will collect miscellaneous drains from areas using caustic and sulphuric acid (only during maintenance and abnormal scenarios – e.g. spillages). This tank may be discharged to the WWTP. The export flow rate from the tank is 27.8 m^3/h.

6.8.4.2. Product Specification

Table 6-17: Effluent Discharge Limits to the Sea

Parameter	Unit	Proposed limits	Comment
Total inorganic nitrogen	mg N/L	15	Annual average
NH_4-N	mg N/L	5	Annual average
Total nitrogen (Note 1)	mg N/L	25	Annual average
Amine and amine degradation products	-	-	Because there are no separate guidelines for amine and amine degradation products, the starting point taken is that they should be covered by the limits for total nitrogen. This is to be confirmed by Shell through direct toxicity assessment of amine and amine degradation products and SEPA consultation.
NH_3 (dissolved gas)	mg/l	0.021	
pH	Range	6-9	
Flowrate	m^3/hr	HOLD	To be determined by Vendor.

Note 1: Total nitrogen is comprised of ammonia, ammonium salts, nitrites, nitrates and organic nitrogen component

6.8.5. Capacity and Flexibility

All rotating equipment needs to be spared with an N + 1 capability required.

6.8.6. Equipment Sizing Report

Final sizing shall be confirmed by the waste water treatment plant vendor during Detailed Design.

6.8.7. Process Control Requirements

The process control of the waste water treatment plant shall be developed by the vendor during the Detailed Design phase of the project.

6.8.8. Interfaces and Effluents

Waste flows are:

- An estimated sludge flow of 150 – 600 ton/year (respectively 25 and 14% dry solids).

6.8.9. Safeguarding Requirements

The integration of safeguarding systems for the WWTP will be performed during Detailed Design.

6.9. Carbon Capture, Compression and Conditioning Electrical System

6.9.1. Source of Power Supply

6.9.1.1. 132 kV Feeder

The FEED design considers power supply to the CCCC plant via a single 132 kV feeder from the National Grid substation located on the opposite side of the A90 to the power station. An existing spare feeder Circuit Breaker 990 which was previously used to supply the decommissioned power station Generator G3 shall be used.

The protection and metering associated with Circuit Breaker 990 shall be updated and modified to meet the latest codes, standards and the metering requirements.

New 132 kV power and control cables shall be installed from the National Grid substation to the main CCCC plant substation ESS-3000. This will involve a new road crossing of the A90 and the route will be on the north side of the existing power station to National Grid substation HV cable route.

When excavating the cable corridor, care shall be taken not to disturb or damage existing cables. A full survey shall be carried out during Detailed Design to accurately identify the location of all underground cables within the areas considered for use by the PCCS Project.

The FEED RAM study work considered the option of having dual 100% 132 kV power supplies and concluded that a single 132 kV supply would achieve an acceptable reliability for the site.

6.9.1.2. 11 kV Distribution

The CCCC plant shall be supplied from two substations. The main substation ESS-3000, supplied at 132 kV via a step-down transformer, is located in the compression area and the second substation ESS-2000 is located in the Carbon Capture Plant and is supplied at 11 kV from ESS-3000.

The power distribution is shown for the Substation ESS-3000 One Line Diagram [43] and Substation ESS-2000 One Line Diagram [44].

The incomer on the 11 kV Main Switchboard 02SB-3001C located in substation ESS-3000 shall be rated for the full load of the CCCC plant. From the figures in the FEED electrical load list it shall be suitable for a peak overall load demand of approximately 34.5 MVA. A short circuit study has been carried out in FEED to determine the required prospective short circuit rating at each switchboard; these ratings are shown on the one-line diagrams.

The 11 kV distribution system shall provide each area of the CCCC plant with two incomers from the main 11 kV switchboard. Each of these shall be rated for a minimum 125 % of the peak load demand, therefore providing each plant with a 100 % redundant system (n + 1), and allowance for future demand increase.

The 132/11 kV transformer will be a star/delta device and will therefore require an earth reference point on the 11 kV distribution system.

This earthing arrangement shall consist of a single feeder on the main 11 kV switchboard connected to a neutral earthing transformer and resistor which shall be rated to restrict the earth fault current to a level within the tolerance of the equipment and protective devices selected, as well as taking into consideration earth leakage from cables and equipment.

The main 11 kV switchboard FEED design allows for one spare incomer and one spare feeder for a neutral earthing resistor should the second incomer be used.

From the main 11 kV switchboard, feeders will be installed to supply subsequent 11 kV switchboards at each substation, these in turn, will provide power to process equipment and distribution to low voltage switchgear.

The 11 kV distribution system will comprise XLPE insulated, armoured cables installed both above and underground to suit the project site conditions.

6.9.2. Electrical Power Distribution for Compression and Conditioning Plant

An 11 kV switchboard 02-SB3002C, for the Compression and Conditioning Plant, shall be installed within the same Substation ESS-3000 as the main 11 kV Switchboard 02-SB3001C. A split bus-bar switchboard shall be provided with a normally open bus-tie vacuum circuit breaker and provided with an auto transfer system designed to restore power should a failure occur to one of the incoming feeders.

Each bus-bar shall be fed from two equally rated 11 kV feeders from the main 11 kV switchboard.

The overall demand of the Compression and Conditioning Plant is estimated at 18 MVA.

Duplicate vacuum circuit breakers and 11 kV feeder cables will distribute power to low voltage switchgear via 100 % rated transformers. Feeders and circuit breakers shall also be provided for supplies to compressors and other process equipment.

The main electrical load is the CO_2 Compressor rated at 15 MW. The motor proposed shall be synchronous type. The configuration of the power supply to the compressor is shown on Substation ESS-3000 One Line Diagram, [43].

Main low voltage, 400 V switchboards will be specified with a split bus-bar system connected with a normally open bus-tie air-circuit breaker and provided with an auto transfer system designed to restore power should a failure occur to one of the incoming feeders.

The 400 V distribution system shall provide power to low voltage motors and general services (lighting and small power) for buildings and site requirements.

Low voltage cables will be XLPE insulated, armoured type installed above ground on ladder rack to the process equipment.

The 400 V distribution system neutral point is proposed as a solid connection to earth potential.

A 400 V emergency switchboard, dedicated for essential and vital loads, shall be provided in ESS-3000 substation. It shall have an incoming circuit from the emergency diesel general and a spare incoming circuit, suitable for connection of a mobile generator. The emergency switchboard in substation ESS-2000 shall be supplied from this board from a single feeder circuit.

6.9.3. Electrical Power Distribution for Carbon Capture Plant

The electrical power supply to the new ESS-2000 substation will comprise two equally rated 11 kV feeder cables routed from the main 11 kV switchboard located in substation ESS-3000.

A split bus-bar switchboard shall be provided with a normally open bus-tie vacuum circuit breaker and provided with an auto transfer system designed to restore power should a failure occur to one of the incoming feeders.

The overall demand of the Carbon Capture Plant is approximately 16.55 MVA. The main electrical load is the booster fan rated at 10 MW.

A three winding transformer is proposed for the supply to the VSD of the booster fan motor. The motor proposed shall be synchronous type. The variable speed unit cubicles will be located in the substation ESS-2000.

Duplicate vacuum circuit breakers and 11 kV feeder cables will distribute power to low voltage switchgear via duplicate 100 % rated transformers. Feeders and circuit breakers shall also be provided for supplies to the booster fan and other large process equipment.

Main low voltage, 400 V switchboards will be specified with a split bus-bar system connected with a normally open bus-tie air-circuit breaker and provided with an auto transfer system designed to restore power should a failure occur to one of the incoming feeders.

Low voltage, 400 V cables will be XLPE insulated, armoured type installed above ground on ladder rack to the process equipment.

The 400 V distribution system neutral point is proposed as a solid connection to earth potential.

A 400 V emergency switchboard, dedicated for essential and vital loads, shall be provided in the substation. It shall have an incoming circuit from the emergency switchboard in substation ESS-3000 and a spare incoming circuit suitable for connection of a mobile generator.

6.9.4. Substations

The switchgear equipment layout will be designed to maximise safety to personnel during operation and maintenance. During Detailed Design an updated power system study should be carried out including performance of arc flash calculations to assess safe working distances and PPE requirements.

6.9.4.1. Switchgear within the Plant Substations

The locations for the substations have been chosen based on the available space on the plot plan and optimising cable lengths to equipment.

11 kV switchgear will be an indoor design, front and rear access and comprise circuit breakers for the incoming, bus-section and transformer feeders. 11 kV motors will be vacuum contactor or circuit breaker controlled depending on rating. Protection relays will be multi-function, microprocessor technology. All circuit breakers and contactors will be motor operated, electrically tripped using 110 Volt DC power.

Switchgear design and layout will take account of the need for containment of an arcing fault.

An Integrated Protection and Control System (IPCS) shall be installed to provide remote control and indication of all main high and low voltage circuit breakers. A remote control panel is also to be installed in the substation to avoid having to stand in front of the switchgear when operating HV circuit breakers, LV incomers or large LV feeders.

Low voltage switchgear is proposed as front and rear access, multi-compartment, to obtain Form 4b separation of compartments design, with incoming and bus-section air circuit breakers. Motor starters are proposed as a withdrawable design, fuse protected contactor with thermal overload and integral isolator/switch device.

6.9.5. Transformers

In general transformers are proposed as hermetically sealed, oil-filled design using oil natural & air natural cooling to IEC60076 and are to be located within external compounds with fire walls between adjacent transformers. Transformers will be specified with a minimum of 20 % future capacity.

Cable connections are proposed for the primary and secondary windings. Transformers will be provided with over-pressure and over-temperature protection devices.

6.9.5.1. Specific Requirements for 132/11 kV Transformer

The transformer shall be naturally air cooled, but designed and equipped so that fans can be fitted at a later date to allow a minimum increase in rating of 25 %. During Detailed Design it is envisaged that the selected transformer manufacturer shall submit calculations to substantiate temperature rises for both the natural air cooled and fan air cooled ratings. All components shall be rated to meet this requirement. Transformer windings shall be copper.

The transformer shall be provided with a hot oil temperature indicator and additional contacts to control cooling fans. The indicator shall be a dial-type calibrated in degrees Celsius and fitted with two adjustable setting contacts, for remote alarm and trip purposes, and a hand-reset pointer to register the highest temperature attained. The sensing devices shall be positioned so that "top oil/liquid" temperature can be measured and visually seen even when the transformer is in a "cold" condition.

The magnetic circuit of the conservator type transformer shall be bonded to the clamping structure through one removable core-insulation-test link or strap only. The link shall be placed in an accessible position beneath an inspection opening in the main tank cover. With the bond removed, the magnetic circuit shall be insulated from the clamping and supporting structure and all structural parts.

6.9.6. Emergency Generator (Carbon Capture, Compression & Conditioning Plant)

Emergency Diesel Generators have been installed on the existing power station system and an emergency diesel is also proposed in the FEED design for the CCCC plant. The emergency diesel generator will be designed to automatically start upon failure of the normal main power supply and sized to restore power to the essential loads as required for the Carbon Capture, Compression and Conditioning plant.

The generator unit will be located within a painted steel, weatherproof enclosure complete with radiator, exhaust system, cooling fans, engine/generator control panel and switchgear.

The generator set will be provided with a skid mounted day fuel tank and a separately mounted 24-hour capacity main fuel tank.

6.9.7. AC and DC Uninterruptible Power Supply (UPS) Equipment

Robust and reliable UPS supply units and distribution systems shall be used to supply safety critical systems e.g. process safeguarding systems.

AC UPS systems will be provided to support the instrumentation, control systems and telecommunication systems and will comprise duplicate rectifier/inverter units with automatic static switch and maintenance by-pass. Duplicate batteries will be provided.

AC UPS batteries shall be rated to energise the relevant loads for not less than:

a) 30 min for process plant shutdown
b) 1 h for utility plants;
c) 1 h for outdoor emergency lighting
d) 3 h for indoor emergency lighting
e) 10 min for non-process computer installations;
f) 8 h for fire-fighting and fire alarm systems;
g) 8 h for telecommunication and radio systems.

A 110 Volt DC system will provide the switchgear closing/tripping power supply requirement and comprise duplicate rectifier/charger units. Duplicate 100 % rated batteries will be provided. The minimum battery autonomy duration will be 60 minutes. The DC system rectifiers will be supplied from both the normal and the emergency distribution.

6.9.8. Process Electric Heater

The process electrical heater will be supplied via a dry type-filled transformer and control panel located in the associated substation. The transformer will be located adjacent to or inside the substation and single core feeder cables will be above ground routed to the process heater. The heater control panel will utilise thyristor technology.

6.9.9. Lighting, Small Power and Earthing

6.9.9.1. Lighting

Normal and emergency lighting distribution boards may be located outdoors. Distribution boards will be specified with outgoing circuit miniature circuit breakers. Luminaires located within the process areas will be fluorescent type.

Illumination levels shall be as recommended in appropriate standards, i.e. CIBSE lighting guides.

Process area lighting will be controlled by a photo-electric cell with manual override facility.

Surface industrial type, fluorescent luminaires will be provided for the new substations.

Fluorescent type escape lighting will be provided along the designated escape routes and supplied from the substation emergency generator supported switchgear.

Escape luminaires located within buildings will be self-contained inverter/battery type with a minimum of three-hour autonomy.

Escape luminaires located outdoors will be self-contained inverter/battery type with a minimum of one-hour autonomy.

6.9.9.2. Small Power

Welding socket outlets of the three-phase, neutral and ground type, rated at 63A, shall be provided in rooms or other areas of the processing plant where supplies to portable welding sets and similar equipment may be required, located so that the necessary coverage of the room or area may be achieved with flexible cables not exceeding 30 m in length.

Convenience 230 V, 16 A socket outlets in process areas shall be provided on the basis of adequate plant coverage, assuming the use of 20 m extension cords. In operating offsite areas, convenience outlets shall be installed on the basis of adequate coverage using 30 m extension cords. Convenience socket outlets shall be arranged in groups of not more than six for distribution branch circuit and shall be protected by miniature circuit breakers providing overload, short circuit and 30 mA ground leakage protection of the circuit.

Socket outlets for use in industrial, non-hazardous areas shall be of the industrial type complying with IEC 60309.

Welding and convenience socket outlets for installation in hazardous areas will be of the explosion-proof Ex-deconstruction. Outlets shall have integral isolating switch and interlocking mechanism such that: The plug cannot be withdrawn unless the isolating switch is in the "open" position and the isolating switch cannot be closed until the plug is fully engaged.

6.9.9.3. Earthing and Lightning Protection

Process and utility areas will be designed with an underground copper earth conductor system.

The earthing system will be designed according to IEEE 80 and BS 7430.

The cables for the low voltage transformer winding neutral to earth connections will be fully insulated for the system voltage and sized to withstand the maximum system earth fault current.

The earthing network in each process and utility area will be designed as non-insulated underground copper conductors with proprietary exothermic weld kits to form an interconnected mesh. Steel-cored, copper-clad earth electrodes will be provided. Earth bars will be located adjacent to the process equipment areas.

Lightning protection will be provided to the process equipment areas and specified to IEC 62305. All above grade installed earthing cable will be copper conductor, green/yellow PVC insulated.

The metallic enclosures of electrical equipment shall be bonded to the plant earth grid. The metallic enclosures of non-electrical equipment, e.g. vessels, shall also be bonded to the plant earth grid or be provided with their own duplicate earth electrodes; in the latter case, the combined resistance to the general mass of earth shall not exceed 10 Ω.

Due to the proximity of the project to Peterhead Power Station a study shall be carried out to ensure step and touch potentials across the PCCS project areas are within safe limits. Calculations in accordance IEEE 80 (including all supplements and amendments) shall be carried out and recommendations from the findings applied to the construction of earth grids and bonding of all equipment, buildings, fences, etc.

6.9.9.4. Static Earthing

When the earthing/grounding or bonding is provided by an entirely metallic path, a bonding resistance of less than 10 Ω shall be achieved. A higher resistance indicates that the intended metallic path is not properly established, possibly because of corrosion or loose connections.

7. Pipeline

7.1. Codes and Standards

7.1.1. Applicable Codes and Standards

The existing Goldeneye pipeline was designed and built in accordance with the requirements BS 8010 Part 3, which has since been withdrawn and replaced with BS PD 8010-2.

International and national pipeline design codes are very prescriptive for pipelines in general, but the transportation of dense phase CO_2 is not specifically covered. The DNV recommended practice DNV RP J202 seeks to address the gaps in the existing standards.

Shell Design and Engineering Practice (DEP) for Pipeline Engineering DEP 31.40.00.10-Gen, which is based on ISO 13623 and also refers to the DNV RP J02 for CO_2 pipelines, specifies the requirements and gives recommendations for the design, material procurement, construction, testing, operation, maintenance and abandonment of rigid steel pipelines (both onshore and offshore) used for the transport of hydrocarbons and other fluids. DEP 31.40.00.10-Gen states that where an alternate standard – other than ISO 13623 – is applied, the DEPs shall be read as providing the minimal Shell requirements that shall be applied for the safe design, installation and operation of a pipeline system.

To ensure a consistent and robust approach for the Peterhead CCS transportation system design, the pipeline, landfall and riser shall be designed in accordance with the DEPs and the requirements of ISO 13623 shall be replaced with those of BS PD 8010-2; supplemented by DNV RP J202 as is appropriate ensuring that the most stringent requirements are applied.

7.1.2. DEM1 Process Safety

Shell's internal DEM1 Process Safety process and associated tools have been used to assess the applicable pipeline safety requirements against the proposed codes & standards strategy.

As the pipeline design was progressed through FEED, the applicable DEM1 requirements were reviewed and the associated process safety risks assessed for the specific design and operating conditions.

For Non Process Safety related lower case "shall" statements within the applicable DEPs (DEM1 and non DEM1), where a deviation was required, the contractor was required to raise a Technical Deviation Request (TDR) for approval with the relevant Shell Technical Authority in accordance with Shell's standard procedures.

7.1.3. Order of Precedence

The order of precedence between the codes and standards applied to the project is:

1. Statutory law and regulations;
2. Specific project approved amendments; and
3. Corporate mandatory requirements and other DEP requirements.

International codes and standards.

7.1.4. Pipeline Design Code Break

The pipeline design code break has been determined in accordance with DEP 31.40.10.13-Gen, Figure 5A. The pig trap facilities shall be designed, constructed and tested in accordance with the requirements of DEP 31.40.10.13-Gen and to the same design code as the pipeline. A high level schematic is shown in Figure 7-1 which identifies the location of the pipeline code breaks for Peterhead CCS export system.

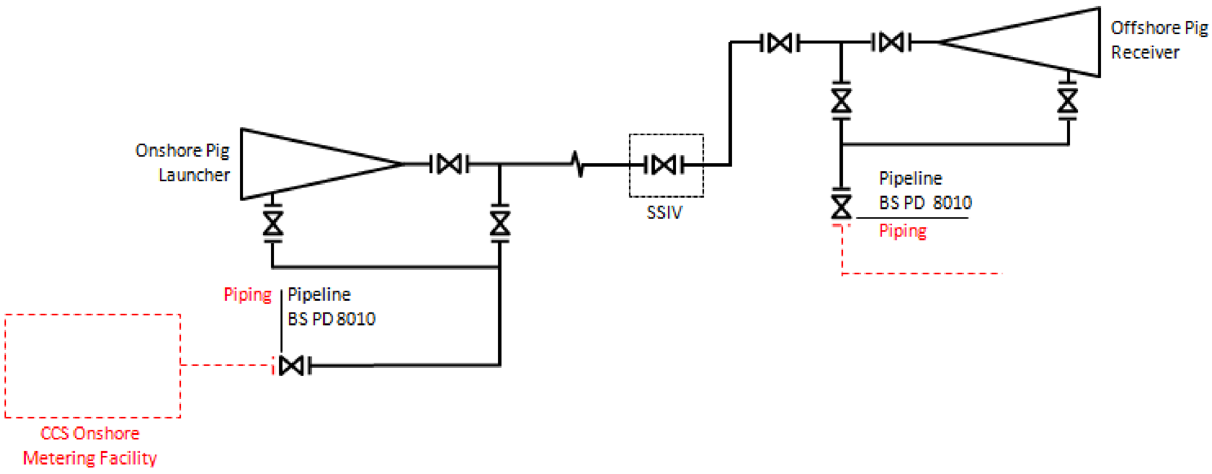

Figure 7-1: Pipeline Design Code Break

The pipeline design code limits are also shown on the following project drawings:

- Process Flow Scheme, Goldeneye Topsides Facilities for Carbon Storage [45]
- Overall System Process Flow Scheme [46]
- Process Engineering Flow Scheme Symbols and Legend [47]
- Onshore Pig Launcher Process Engineering Flow Scheme [48]
- SSIV Process Engineering Flow Scheme [49]

7.2. Pipeline System Description

7.2.1. Overall Field Layout

Following compression, conditioning and metering at Peterhead Power Station, the CO_2 is piped to a new onshore pig launcher facility which is located in the area formerly occupied by the heavy fuel oil tank farm. From the pig launcher, the pipeline is routed directly offshore via a new 20-inch (508 mm) carbon steel pipeline.

There will be a short length of pipeline, as the pipeline exits Peterhead Power Station, comprising the 900 m landfall. The selected FEED solution is construction using the trenchless installation method, Horizontal Directional Drilling (HDD). However, the acceptability of this proposed solution requires to be confirmed. The landfall design will be developed further in Detailed Design.

En-route to the Goldeneye pipeline, the new pipeline crosses two existing pipelines, the 20-inch Fulmar A to St Fergus gas pipeline (PL208) and the 28-inch Britannia to St Fergus gas pipeline (PL1270). It is proposed the pipeline is tied in at KP19.6 along the existing 20-inch carbon steel Goldeneye pipeline. An alternative tie-in location at Goldeneye KP 19.3 has 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-inch 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.

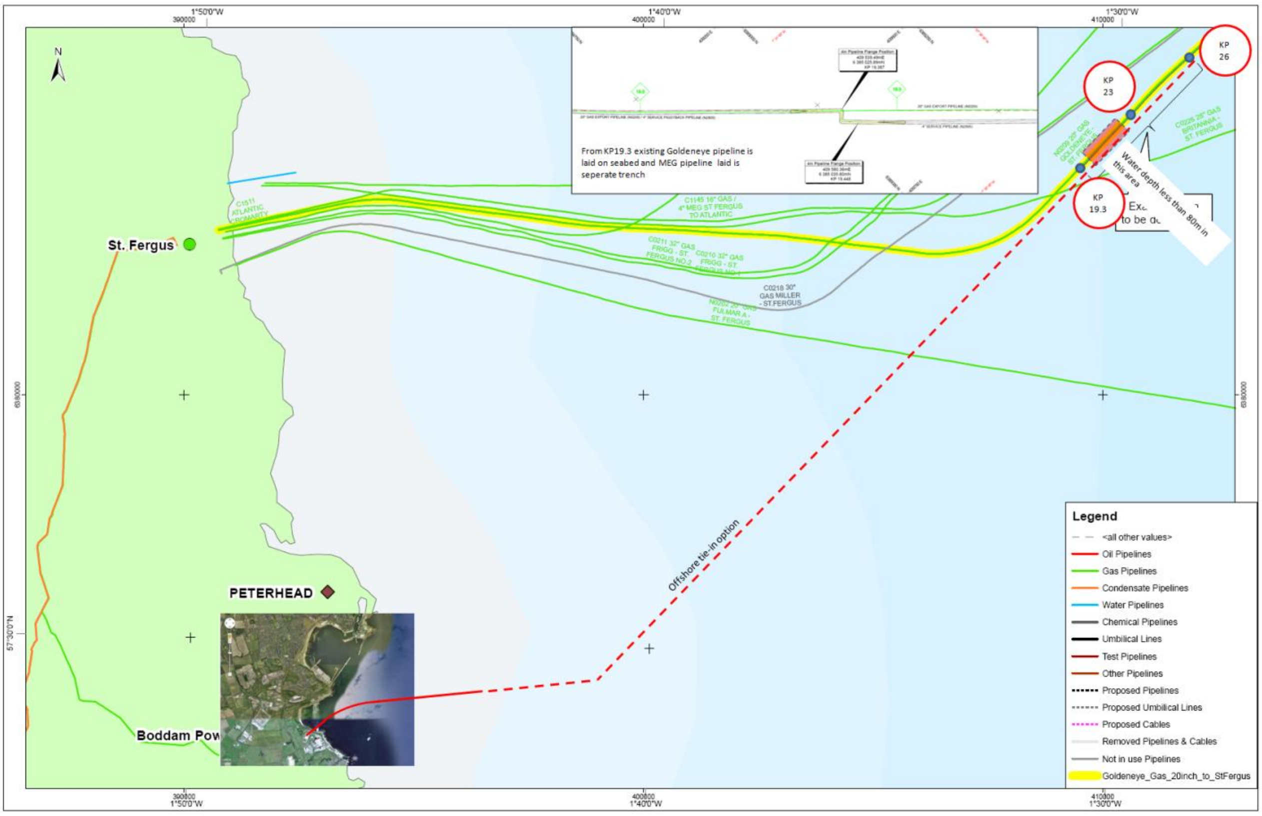

Figure 7-2: Field Layout from PPS to Goldeneye Pipeline Tie-in

From the tie-in, the CO_2 is exported through the existing pipeline, approx. 78 km in length, to the existing Goldeneye platform for injection into the depleted Goldeneye field which is located approximately 100 km north east of the Aberdeenshire coastline.

The subsea arrangement at the Goldeneye platform is shown in Figure 7-3.

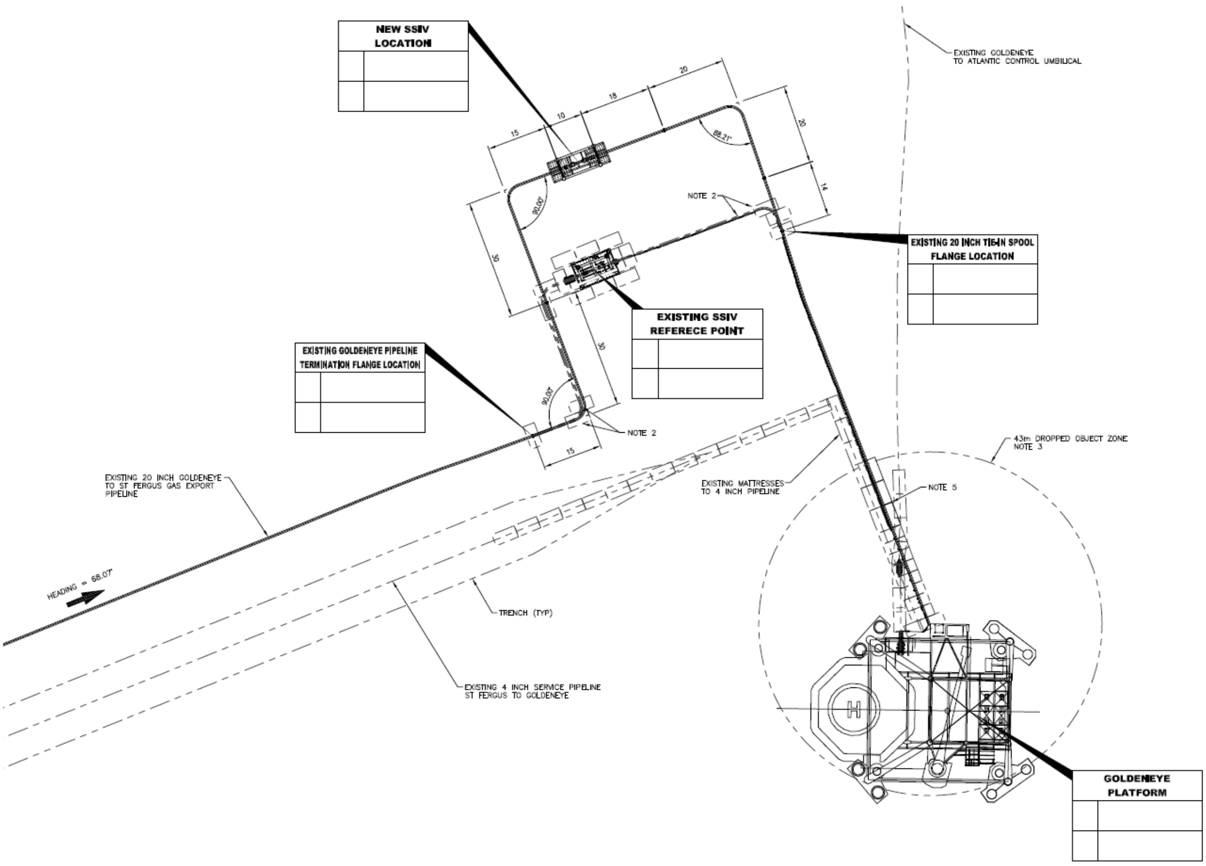

Figure 7-3: Subsea Arrangement at the Goldeneye Platform

In addition to the 20-inch CO_2 export pipeline, the existing 4-inch pipeline has been assessed for extension of the design life and change of service. It has been found to be suitable and will remain intact running from St Fergus to the Goldeneye platform and will be used to enable injection of methanol into the wells.

7.2.2. Pipeline Scope

The design boundary limits for the pipeline system scope are shown shaded in yellow in Figure 7-4 and are defined as follows:

7.2.2.1. Onshore Plant

The design scope limit for the pipeline at Peterhead Power Station is defined as the upstream Ring Type Joint (RTJ) flange of the onshore maintenance valve immediately after the onshore dense phase CO_2 metering facilities. The new capture, conditioning and compression facilities, including the metering, at Peterhead Power Station are to be designed by the CCCC plant Contractor.

The scope limit of the design for the purpose of the pre-commissioning and commissioning activities is the onshore pig launcher.

7.2.2.2. Goldeneye Platform

The pipeline design scope limit is the upstream circumferential weld on the riser ESDV at the top of the platform riser. The platform pipeline section, pig receiver facilities and topsides piping are to be designed by the Topsides Contractor.

The scope limit of the design for the purpose of the pre-commissioning and commissioning activities is the platform pig receiver.

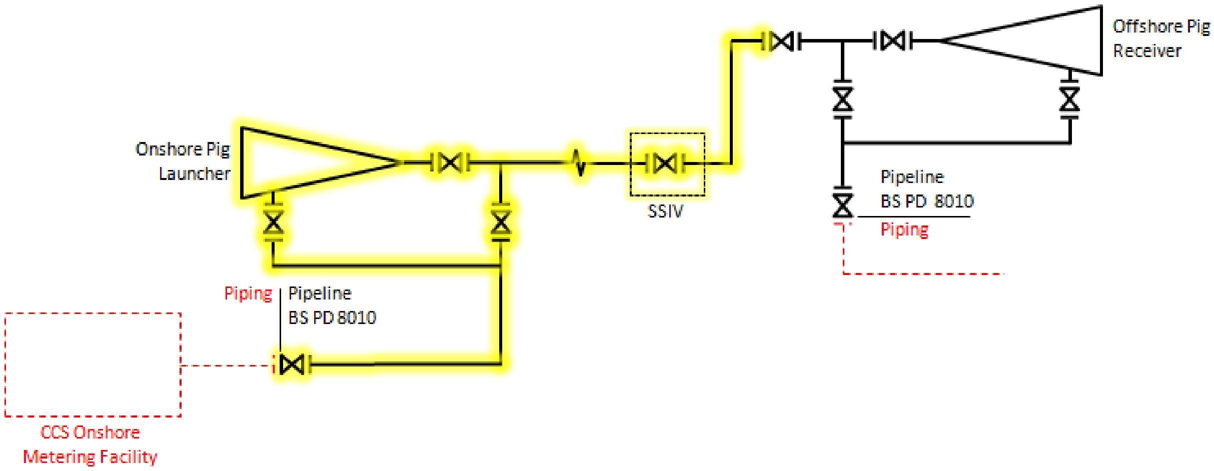

Figure 7-4: Pipeline FEED Contractor Design Scope Limits

7.2.3. Pipelines and Subsea Design Scope

In summary, the Peterhead CCS pipeline system comprises:

- New onshore pig launcher facility;
- New 900 m HDD landfall;
- New 21.8 km 20-inch carbon steel CO_2 export pipeline from Peterhead Power Station to a subsea tie-in to the existing 20-inch Goldeneye pipeline – Refer to the Overall Field Layout drawing [50];
- New CO_2 export pipeline subsea flanged tie-in arrangement;
- Replacement of SSIV including replacement of a number of the tie-in spools, the associated control facilities (New umbilical and topsides TUTU);
- Existing riser tie-in spools;
- Existing platform riser;
- Re-use of the existing 4-inch carbon steel methanol line from St. Fergus to the Goldeneye platform.

7.2.4. Pipeline Routing

Project-specific survey data was gathered and used in conjunction with existing sources of information to confirm suitability of the preliminary route selection. The following general routing and installation constraints have been considered:

- Minimisation of Health and Safety risks;
- Minimisation of environmental impact, including flora and fauna;
- Shortest achievable route where possible;
- The pipeline will follow existing route corridors where possible, subject to minimum spacing requirements;
- Capital Expenditure (CAPEX) cost to be minimised;

- Existing infrastructure/third party crossings are to be minimised, where possible;
- Pipeline installation method and construction, including limitations and constraints;
- Cognisant of shore approach and landfall design;
- Cognisant of geotechnical and geophysical seabed conditions;
- Cognisant of seabed features, obstacles and ship wrecks;
- Shipping and fishing interaction, including near-shore anchorages; and
- Future tie-ins and expansion flexibility.

There will be a short length of onshore pipeline, as the pipeline exits the compression plant at Peterhead Power Station, mostly comprising the landfall which will be constructed using a trenchless installation method. The pipeline is routed directly offshore in an easterly direction from Furrah Head, avoiding the sewage pipe outfalls to the north and the skerry (a small tidal rock island) to the south, refer to HDD Shore Approach Plan Route and Longitudinal Profile, [51].

Several engagement sessions with key offshore stakeholders including Marine Scotland, National Federation of Fishermen's Organisations (NFFO), Scottish Fisheries Federation (SFF), the Peterhead Port Authority, Scottish Natural Heritage (SNH) (in relation to the shoreline Special Protection Area) and the Joint Nature Conservation Committee (JNCC) have taken place. None of these stakeholders raised any concerns of note, with regard to the offshore pipeline option. Engagement with SNH indicated that should a trenchless installation method be considered unfeasible, open cut trenching through the marine extension to the Special Protection Area (SPA) could be considered.

At approximately 12 km from shore the pipeline heads north-east towards the Goldeneye pipeline, crossing two existing pipelines, the 20-inch Fulmar A to St Fergus gas pipeline (PL208) and the 28-inch Britannia to St Fergus gas pipeline (PL1270). Both pipelines are laid on the seabed.

The pipeline will be routed parallel to the existing 20 inch Goldeneye pipeline before being tied in at KP 19.6 (existing Goldeneye pipeline reference) at a water depth of approximately 80 m. The approximate length of the new pipeline section will be 21.6 km.

7.2.5. Landfall

The landfall is located within Sandford Bay, a relatively small enclosed bay immediately north of Peterhead Power Station. It is also noted that the landfall is within the 2 km marine extension of a Special Protection Area (SPA) designated for nesting seabirds under the Habitats Directive.

The landfall is routed directly offshore in an easterly direction to a subsea exit point in approximately 12 m water depth which will enable subsequent subsea pipelay operations to be performed from standard lay barge vessels. The proposed length of the landfall is 900 m. Following review of the results of the geotechnical surveys it is proposed the landfall shall be installed by Horizontal Directional Drilling (HDD) using forward reaming. A pilot hole was drilled in early 2015 which confirmed that the identified route was suitable for HDD installation. The pilot hole was grouted up to stabilise the hole for the interim period and will be drilled out and enlarged when the landfall works are undertaken in the Execute phase.

The route has been established to avoid existing known hazards/constraints in the area which include:

- Twin outfalls from a sewage treatment plant on the north side of the bay run in a south-easterly direction to an exit point approximately 700 m from the coast. It is understood that the outfalls were installed by burial within an excavated rock trench, backfilled and armored with graded stone. The outfalls terminate within a designated spoil ground, which covers a large area of the central part of the bay and are marked on site by a yellow buoy;
- The skerry, a tidal rock island approximately 700 m north-east from the headland near Boddam Harbour;
- The existing power station outfall is present just to the west of Furrah Head and discharges in a northerly direction across the bay.

The proposed route is shown below in Figure 7-5.

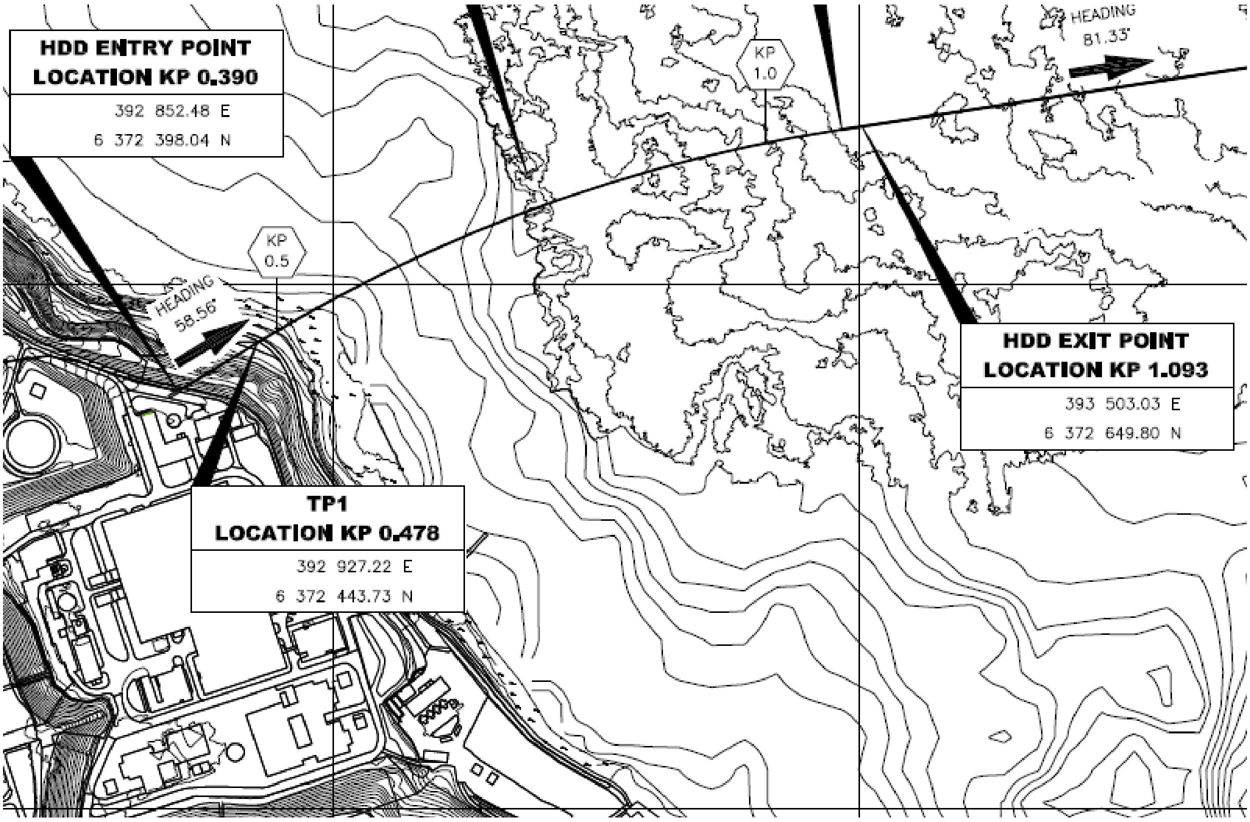

Figure 7-5: HDD Shore Approach

The onshore geotechnical conditions comprise variably weathered Peterhead Granite to considerable depth in places and the weathering is concentrated along faults, joints and discontinuities whose location, orientation and persistence is difficult to predict. Offshore, it is believed that the ground conditions comprise one or two layers of glacial till overlaying the moderately to highly weathered granite. The till is reported to contain gravel and boulders and the weathered granite contains numerous discontinuities, which could be a challenge for HDD. In addition, the interface between the igneous and superficial deposits is unknown and varies in elevation. Offshore geotechnical surveys have been performed during Q4 2013 and onshore boreholes in Q1 2014. This information has been assessed to confirm the technical suitability of HDD installation, together with initiation and exit points.

7.2.6. Pipeline Crossings

Two third party pipeline crossings have been identified which are detailed in Table 7-1. The design of these crossings shall be in accordance with DEP 31.40.10.13-Gen and is required to consider the following aspects:

- Pipeline bending stress;
- Free spans prior to rock dumping;
- Settlement; and
- Protection.

Details of the crossing design may require submission to the owners of the lines being crossed for their written acceptance of the design.

Table 7-1: Pipeline Crossings

Crossing Reference	Description	Ref	Type	Diameter (inch)	Status
PLX1	Fulmar A to St Fergus	PL208	Gas	20	Exposed on seabed
PLX2	Britannia to St Fergus	PL1270	Gas	28	Exposed on seabed

7.2.7. Cable Crossings

The pipelines cross one cable that has been abandoned and sections are believed to have been removed. The results of the Q4 2013 offshore survey identified the existence of the abandoned cable. A crossing will be constructed using flexible concrete mattresses.

National Grid and SSE are proposing a number of developments within the Peterhead area, including two High-Voltage Direct Current (HVDC) projects, namely the:

- Eastern HVDC Link between Peterhead and the North-east of England;
- North Connect HVDC Interconnector between Peterhead and Norway which is a commercial joint venture (JV) between SSE, Vattenfall and three Norwegian municipal power utilities.

Both these developments propose to route cables into Sandford Bay. The currently proposed pipeline routing has been selected to ensure these will have a minimal impact. However, it will be necessary to construct a simple crossing over each cable.

7.2.8. Tie-ins

The pipelines shall be designed as a fully welded system throughout the total length of the pipeline (including in-line valves) with the exception of the subsea Goldeneye pipeline tie-in, the SSIV connections and the riser tie-in spools, which will be flanged.

7.2.8.1. Landfall Tie-In

The above water welded tie-in will be required to connect the landfall pipeline to the offshore pipeline.

7.2.8.2. Goldeneye Subsea Tie-In

The new pipeline section shall be tied in at KP 19.6 to the existing 20-inch carbon steel Goldeneye pipeline. An industry review of available connector technology was undertaken during FEED and a short list of suitable connector suppliers was established. A technical note was prepared proposing the use of the mechanical connector technology for CO_2 service on the Peterhead Carbon Capture and Storage (PCCS) project. This was reviewed and approved by Shell Pipeline Technical Authorities with the following conclusions drawn:

- Corrosion by exposure to dense phase CO_2 will be prevented by ensuring the water content of the CO_2 stream is maintained below the specified limit;
- Graphite and thermoplastic seals are more compatible with dense phase CO_2 service than elastomeric seals;
- A testing program has already been proposed for non-metallic valve seals for topsides application. This is being progressed independently from the project as part of the KKD 11.064 - Technology Maturation Plan [6];
- A leak past the seals could lead to brittle fracture of the pipeline or connector body due to rapid expansion and cooling of dense phase CO_2;
- Risk of galvanic corrosion leading to degradation of carbon steel surrounding a graphite seal is considered low.

These conclusions lead to the following requirements:

- Laboratory qualification testing (using Shell or vendor labs) shall be performed to confirm the suitability of the proposed seal selection for the mechanical connector to avoid low temperature damage and decompression issues in dense phase CO_2. This is to be done in line with the testing proposed for valve seals under the KKD 11.064 - Technology Maturation Plan [6];
- A low temperature assessment of the pipeline to define a Minimum Allowable Temperature (MAT) during a leak past the seals, based on pressure, wall thickness and Charpy impact test data shall be performed;
- A low temperature grade carbon steel shall be selected for the connector body.

The above mentioned technical note was issued as part of the Landfall, Pipeline & Subsea EPC Invitation To Tender (ITT) and clearly communicated to tenderers. A clear understanding of requirements for the mechanical connector was demonstrated by tenderers who have agreed to comply with all recommendations.

During Execute the selected connectors will be qualified for use in dense phase CO_2 in line with the recommendations.

7.2.8.3. Riser Tie-In Spools

It is the intention to re-use all but one of the existing tie-in spools between the riser and the SSIV structure. This decision was made for various reasons, not least of which is to reduce diver exposure time and minimise the number of flange connections in the pipeline system. However, prior to FEED a concern was raised that the spools could become over-pressurised under certain specific environmental conditions in the event the riser inventory is shut-in. This has been checked during FEED and confirmed to be highly improbable and the proposed design meets Shell's ALARP requirements.

7.2.9. Pipeline Operating Constraints

The CO_2 injection wells at the Goldeneye platform have a pre-defined maximum and minimum operating injection flowrates, based on the size of the inner tubing of the well. There are different sections of 4 ½ inch and 3 ½ inch tubing depending on the well. From the Christmas tree to Tubing Retrieval Subsurface Valve there will be 4 ½" tubing. The maximum well injection rate is governed by the tubing diameter and furthermore limited by the pipeline Maximum Allowable Operating Pressure (MAOP). The minimum injection rate is limited by the low design temperature constraint downstream of the topsides choke valve. The range of CO_2 flow rate considered in FEED was between 89.9 t/h and 138 t/h.

7.2.10. Pipeline Design

7.2.10.1. Mechanical Design

The 20-inch export pipeline will be installed by the S-Lay method and will be buried. The wall thickness for the new 20-inch CCS export pipeline has been assessed for pressure containment, hydrostatic collapse and propagation buckling in accordance with the requirements of BS PD 8010. The required wall thicknesses for the main section of the new 20-inch (508 mm OD) pipeline is: 14.3 mm. Heavier wall pipe is required at the shore crossing and onshore section.

7.2.10.2. Weight Coating

The 20-inch CO_2 export pipeline shall be externally coated with steel reinforced concrete to ensure pipeline stability. In addition the pipeline will also be trenched to the tie-in point at KP 19.6 to meet the full stability requirements. As per the original Goldeneye pipeline design, the concrete weight coating shall comply with the requirements of DEP 31.40.30.30-Gen.

7.2.10.3. Anti-Corrosion Coating

To protect the pipelines against external corrosion, an anti-corrosion costing system shall be applied. The anti-corrosion coating requirements have been selected in accordance with DEP 31.40.30.31-Gen and DEP 31.40.30.32-Gen.

7.2.10.4. 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 this has demonstrated that the epoxy coating is resistant to dense phase CO_2 exposure and a lab analysis of pig returns from the recent hydrocarbon freeing programme confirmed no evidence of coating spalling or disbondment. The requirement for long-term testing shall be reviewed and considered during Detailed Design.

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

7.2.10.5. Cathodic Protection

The offshore pipeline cathodic protection system will consist of conventional sacrificial anode bracelet half shells attached to the pipeline at regularly spaced intervals. The sacrificial anode cathodic protection system design shall be based on DEP 30.10.73.32. A method for cathodic protection of the onshore pipeline section shall be determined during Detailed Design in accordance with requirements of DEP 30.10.73.31. It shall be ensured that the total length of the pipeline is fully protected.

Test points, complete with reference electrodes, shall be installed on the onshore section of the pipelines. The purpose of the test points is for testing for interference from other services and structures, checking the cathodic protection integrity and checking for holidays (unacceptable discontinuities such as pinholes and voids) in the pipeline coating.

7.2.10.6. Pipeline Protection

The new section of pipeline will be protected near-shore by rock-dumping and from approx. KP 3 to KP 19.6 will be protected using a combination of trenching, backfill and rock-dumping.

7.3. Existing Goldeneye Pipeline Facilities

7.3.1. Pipeline

The Goldeneye pipeline was installed in 2004 and operated until December 2010. The corrosion risk of the pipeline was evaluated using the PipeRBA (Risk Based Assessment) approach and no internal inspection was performed.

Hydrocarbon freeing was completed in May 2013. The pipeline has been cleaned to 5 ppmv oil in water and left mothballed with inhibited water containing the chemical RX-5227, which is a corrosion inhibitor, oxygen scavenger and biocide combination product, at 1000 ppmv.

Less than 1 kg in total of solids was recovered during the hydrocarbon freeing operation. A deposit analysis of samples recovered from the pigging operations was performed and a summary of the results is presented below in Table 7-2. The results are expressed as a percentage of the original sample and are the most likely combination of anions and cations found to be present.

Table 7-2: HC Freeing Deposit Analysis Results

Component	% of Original Sample	
	2013-001584	2013-001585
Water	56.6	46.7
Iron oxide as Fe_3O_4 (Magnetite)	22.4	32.6
Organics (2)	9.1	10.8
Calcium sulphate	3.4	1.1
Acid insolubles (1)	2.5	3.0
Sodium sulphate	1.5	0.3
Carbon	1.4	1.3
Magnesium sulphate	1.1	2.7
Other	2.0	1.5

Notes:

1. The acid insolubles were examined by Fourier transform infrared spectroscopy (FTIR) and were found to contain traces of silicates, traces of barites and amorphous solids.
2. The organics were identified as hydrocarbons.

To confirm the pipeline wall thickness and identify any potential metal loss, an inspection pigging programme has been developed, with a planned execution date of Q2 2016. The pigging operation combines both ultrasonic (UT) and Magnetic Flux Leakage (MFL) technologies. Furthermore the inspection will serve to distinguish between metal loss which had occurred during hydrocarbon service and any potential degradation during CO_2 service.

Previous study work done during the earlier Longannet CCS Project FEED study concluded that the existing 20-inch Goldeneye pipeline was suitable for the transportation of dense phase CO_2 with pre-conditions. No significant issues were identified.

7.3.2. SSIV

Pre-FEED work confirmed the existing SSIV and umbilical connection are unsuitable for use. It was thereafter deemed safer and more economical to replace both items, whilst leaving the existing units in place, see Figure 7-6. The new SSIV structure will be of a similar design to the existing unit. The new umbilical will be brought onto the platform through the existing J-Tube J2.

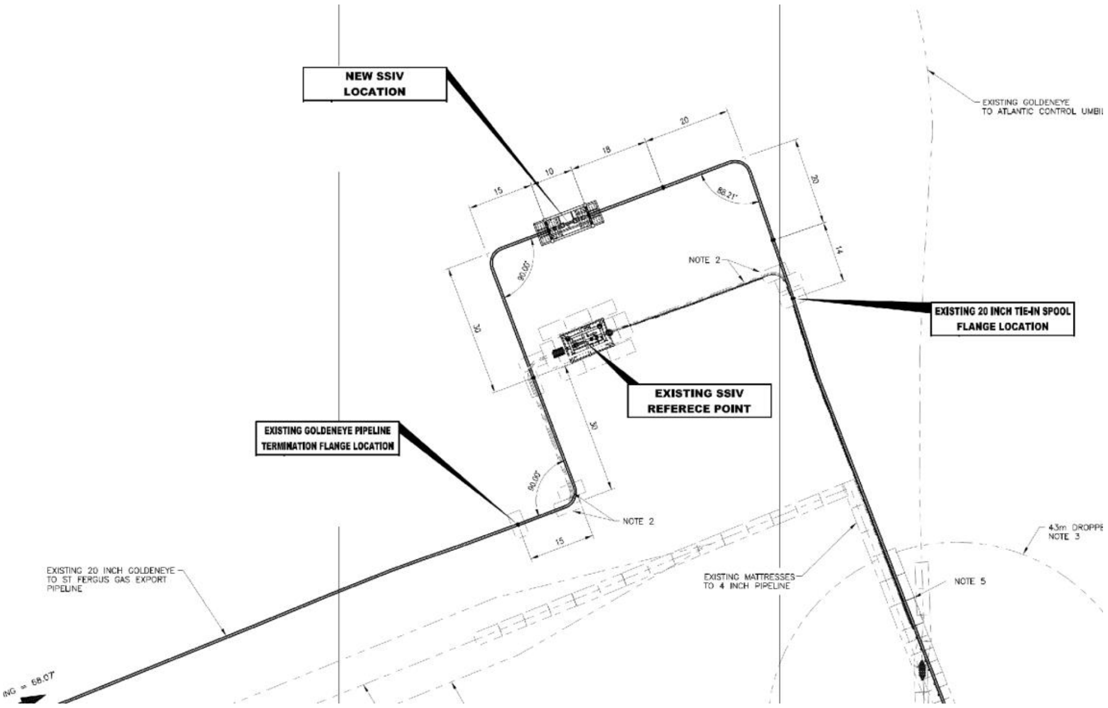

Figure 7-6: SSIV Layout

7.3.3. Riser Spools and Platform Riser

If both the top of riser ESDV and the SSIV are closed simultaneous on a warm sunny day, the cold inventory would be locked in, which could lead to a pressure increase in the riser spool piece system beyond the 132 barg design pressure due to thermal expansion of CO_2. The base case is not to re-rate the spools as risk of overpressure is considered ALARP based on the rarity of the ambient conditions required to cause the scenario. The system operator has sufficient time to intervene manually and vent any built-up pressure using a restriction orifice bypass around the SSIV.

Previous FEED study work performed as part of the Longannet CCS project concluded that the existing 20-inch carbon steel riser is suitable for the transportation of dense phase CO_2.

7.4. Flow Assurance

During FEED, a flow assurance exercise was undertaken for the selected pipeline option. This considered the 20-inch nominal bore dense phase CO_2 pipeline. A summary of the steady state and dynamic simulation work which was performed is presented below along with some discussion on the measures required to prepare the system for CO_2 injection and also to maintain injectivity into the wells during PCCS operations.

7.4.1. Simulation Basis

The selected pipeline option has been reviewed using proprietary software tools. Steady state and dynamic simulation studies were performed in order to confirm the adequacy of the proposed offshore pipeline and determine likely operating constraints. All of the simulation models included representation of both the new and existing pipelines from Peterhead Power Station to the Goldeneye platform. The models demonstrated the feasibility of the preferred pipeline routing and design.

The fluid models were built on a compositional basis using the design specification for CO_2 at the entry to the offshore transportation system, as provided in Section 5.4.4.

The PIPESIM tool has been used to perform the steady state analysis undertaken. The OLGA tool has been used to perform the dynamic simulations. Steady state simulations were also performed in the OLGA model to cross check with results obtained from PIPESIM to provide increased confidence in the obtained results.

The specialist WANDA tool has also been utilised to perform surge analysis. WANDA simulations for fast transients (water hammer) were carried out for the Goldeneye pipeline system transporting dense phase CO_2 from Peterhead to the Goldeneye platform, in order to identify high and low pressure conditions. The primary focus was to analyse the closure of the automated/actuated valves, i.e. ESD valves, valves with ESD function and the SSIV. Three different scenarios were simulated where ESD valves have been closed either simultaneously or individually.

The topography of the CCS pipeline system including the new and existing pipelines is shown in Figure 7-7 for the selected offshore dense phase CO_2 pipeline route.

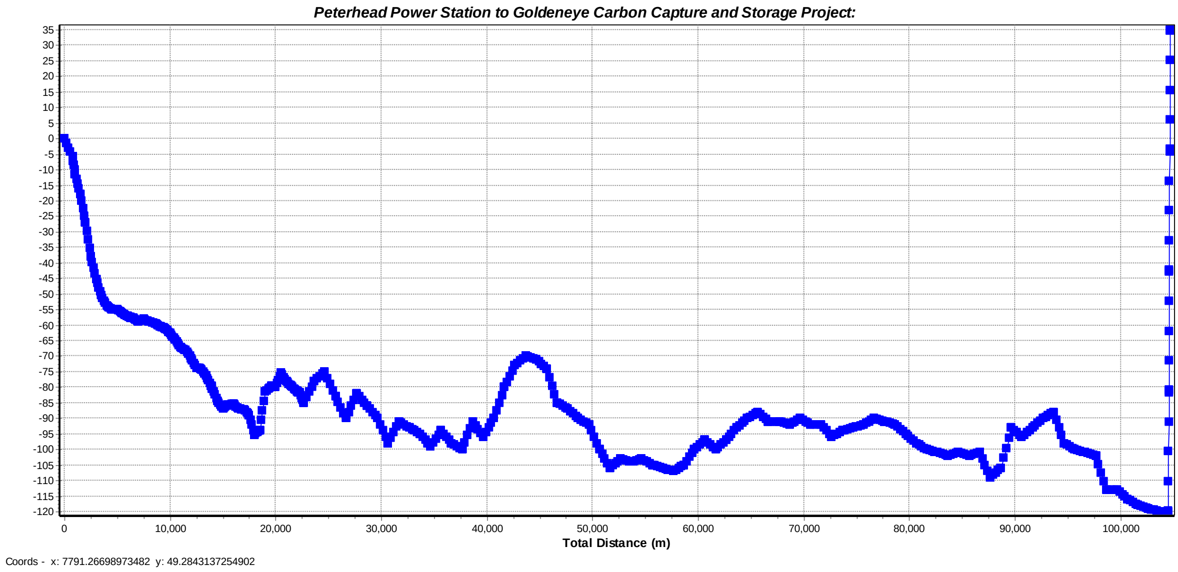

Figure 7-7: Pipeline Topography for the Direct Offshore Dense Phase CO_2 Pipeline Route

The FEED Flow Assurance work will be revisited if detailed design information results in a material change to the basis used in FEED. Additional flow assurance scenarios may be considered in order to provide system information to future PCCS operating guides.

7.4.2. Steady State Simulation Results and Conclusions

A range of pipeline inlet and sea temperature conditions were considered for the steady state simulations as shown in Table 7-3 denoted as study cases FC1 to FC6.

The results obtained from the PIPESIM simulations undertaken are summarised in Table 7-3.

Table 7-3: PIPESIM Summary Results

Case ID.	Mass Flow*	Inlet Press*	Top of riser Press	SSIV Press	System Δy	Pipeline Δi	Inlet Temp*	Top of riser Temp	System Δy	Sea-bed Ambient Temp*	Average Liq Hold-up	Avg. Mixture Vel.
	(kg/hr)	(bara)	(bara)	(bara)	(bar)	(bar)	(°C)	(°C)	(°C)	(°C)	(%)	(m/s)
FC1	138,349	121.0	117.3	130.1	3.7	-9.1	29	9.8	19.2	11.0	100.0	0.23
FC2	89,927	117.0	113.7	126.5	3.3	-9.5	29	9.7	19.3	11.0	100.0	0.16
FC3	138,349	121.0	117.0	130.5	4.0	-9.5	29	2.9	26.1	4.0	100.0	0.23
FC4	89,927	117.0	113.5	126.9	3.5	-9.9	29	2.9	26.1	4.0	100.0	0.15
FC5	138,349	121.0	117.7	131.1	3.3	-10.1	15	2.9	12.1	4.0	100.0	0.23
FC6	89,927	117.0	114.1	127.6	2.9	-10.6	15	2.9	12.1	4.0	100.0	0.15

Note: * Denotes input data used to define specific study cases.

The respective pipeline pressure, temperature and velocity profiles obtained are shown in Figure 7-8, Figure 7-9 and Figure 7-10 respectively.

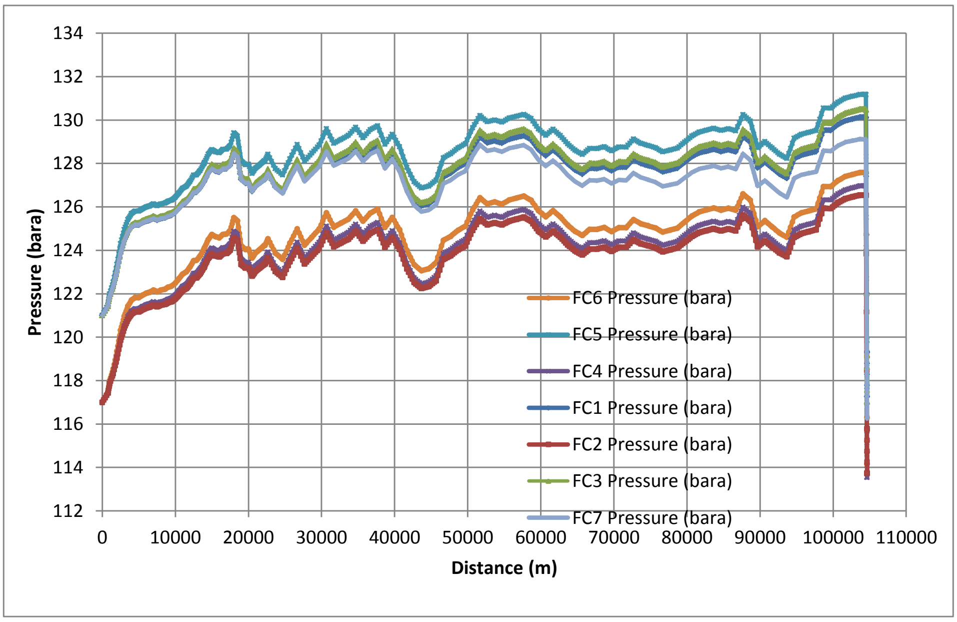

Figure 7-8: Pressure profiles

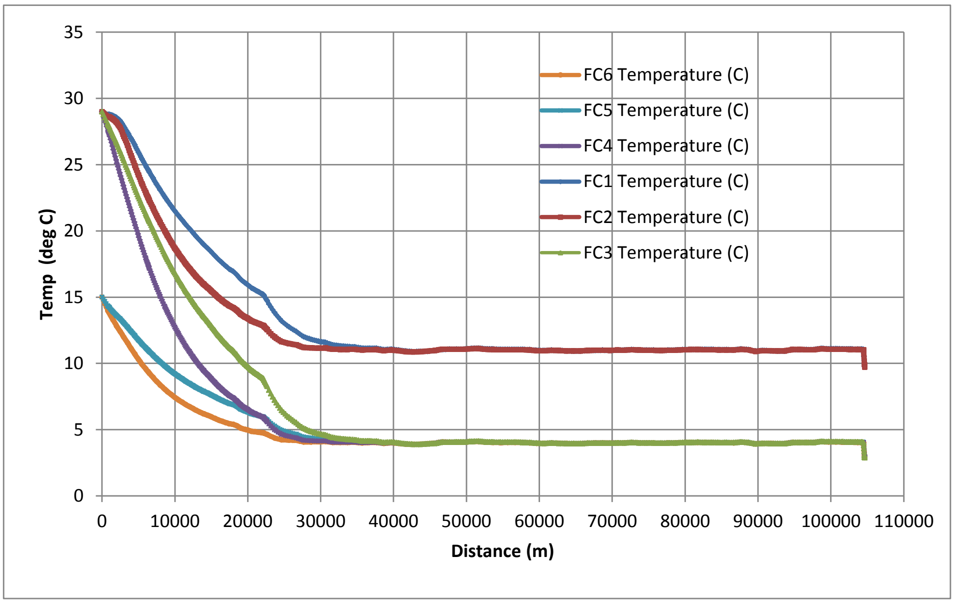

Figure 7-9: Temperature Profiles

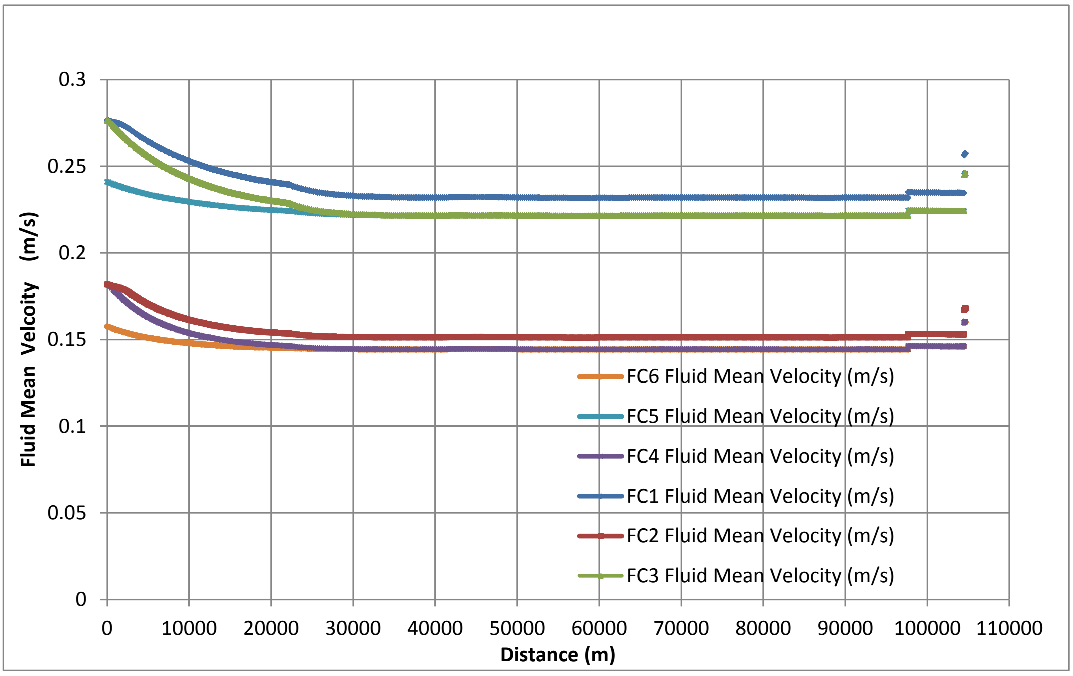

Figure 7-10: Velocity Profiles

For the simulated steady state cases FC1 to FC6, both PIPESIM and OLGA give calculated results throughout. The summary of the conclusions drawn are provided below:

- The absolute pressure drop calculated in all study cases is very small (3-4 bar);
- The frictional pressure drop in the system is of the order of 1 bar;
- Pressure profiles are not be significantly influenced by seawater temperature or by the pipeline inlet temperature;
- The work performed confirmed previous study work and found that the maximum pressure is found close to the bottom of the riser;
- The fluid temperature always reaches the seabed ambient temperature within 35 km of the onshore inlet location; and
- As a consequence of maintaining the use of a 20 inch pipeline throughout, the system velocities are very low (0.15-0.23 m/s) and no significant flow constraints were identified by the studies. The fluid is expected to be clean (i.e. free from solid particles) such that erosion is of no concern.

7.4.3. Dynamic Simulation Results and Conclusions

A number of dynamic simulations were performed in order to assess the reaction time of the system to various step changes in operation such that initial response times could be determined and operating envelopes established for associated control and protection functions. The simulations considered:

- Failure of the Onshore Compressor Discharge Cooler – reaction time for high temperature trip;
- Failure of Onshore CO_2 Export – reaction time of offshore flow control scheme and low pressure trips to prevent vapour breakout in the pipeline;
- Pipeline Settle-Out Conditions;
- Closure of Goldeneye ESD Valve or SSIV – reaction time of onshore high pressure trip to protect pipeline maximum allowable operating pressure;
- Repacking the pipeline;

- Depressurisation of Pipeline via Goldeneye Vent – confirmation of performance of topsides vent system designed to manage subsea minimum design temperatures; and
- Riser over-pressurisation, depressurisation and re-pressurisation.

The main conclusions from this work are given below, with respect to operation at the maximum dense phase CO_2 flowrate of 138 t/h.

7.4.3.1. Failure of the Onshore Compressor Discharge Cooler

Almost immediately after a failure of the onshore compression plant cooling system, the pipeline will be exposed to temperatures higher than the design temperature. This study results indicate that this temperature increase would affect the first 35-40 km of the pipeline and would therefore have an impact on a section of the existing pipeline as well as the new pipeline section.

7.4.3.2. Failure of Onshore CO_2 Export

De-packing is considered to occur when the storage injection rate exceeds the onshore CO_2 production rate. For the de-packing cases considered, the time required to reach the topside under-pressure trip level of 86 bara is between 1 hour and 2.3 hours. This is considered to provide time for the future PCCS System Operator to assess the situation before being obliged to take mitigating action.

If de-packing is allowed to continue below the under-pressure trip setpoint, formation of gaseous CO_2 in the pipeline is predicted to occur within 4.5 hours, assuming the highest (worst case) de-packing rates. This condition is undesirable since this would result in unstable flows in the pipeline and localised low temperatures associated with the Joule-Thomson effect.

7.4.3.3. Pipeline Settle-Out Conditions

If the pipeline is shut in then the results from the study cases evaluated indicated that equilibrium is reached in 200 to 250 hours for the summer conditions, and in 90 to 100 hours for the winter conditions. The average final pressure of the pipeline ranged from 90.3 bara to 121.5 bara. This information will be used to develop the future PCCS full chain operating philosophy during detailed design.

7.4.3.4. Closure of Goldeneye ESD Valve or SSIV

In response to closure of the ESD valve at the Goldeneye platform or the SSIV, the OLGA model predicted the defined pipeline MAOP of 133 bara would be reached in almost 6 minutes. However, the pipeline can potentially be safely operated at higher pressures if the hydrostatic contribution of the seawater is taken into account. For a seawater contribution of approximately 12 bar at the riser base, the maximum internal pipeline pressure at this point is considered to be 143 bara. In the OLGA model, this pressure level was reached after almost 37 minutes.

Further analysis was undertaken using the WANDA specialist simulation tool to perform surge analysis. The performed simulations predicted that the resulting pressure increase is in the order of 2 bar based upon an simulated closing time of 20 seconds as a result of valve operation. However, upon closing of the valves, continued supply into the pipeline would result in the pressure in the pipeline system approaching the maximum allowed internal pipeline pressure. The WANDA study results forecast that this would take approximately 20 minutes.

The OLGA and WANDA studies both indicate that intervention requires to designed into the operation of the system to safeguard the system against the potential to experience excessive pressure and provide some indication of the likely time durations required. This information will be further developed in detailed design.

7.4.3.5. Re-Packing the Pipeline

The time required to complete re-packing operations ranges from 0.9 to 2 hours dependent upon the pipeline settle-out conditions and the subsequent CO_2 production rate.

7.4.3.6. Depressurisation of Pipeline via Goldeneye Vent

A full depressurisation of the offshore pipeline has been simulated under worst case scenario (winter) conditions. Without controlled venting, there is the risk that the vaporisation of liquid CO_2 in the pipeline will result in fluid temperatures dropping below the minimum design temperature of the existing pipeline section (-10°C). As a result, the FEED design proposed a pressure control system to control the rate of CO_2 venting at the Goldeneye topsides. Taking the proposed controlled venting method into account, the OLGA study predicted that the time required to depressurise the pipeline is about 8 to 9 weeks.

7.4.3.7. Riser Over-Pressurisation, Depressurisation and Re-Pressurisation

The FEED study work confirmed earlier analysis identifying a risk of over-pressurisation of the existing Goldeneye riser and SSIV tie-in spool, due to ambient warming of a locked-in CO_2 inventory. This is due to the high thermal expansion coefficient of CO_2, which causes a significant pressure increase upon warming up. This particularly relevant for the SSIV tie-in spools which have a maximum design pressure of 133 bara.

The extent of the thermal over-pressurisation depends on the initial pressure of the locked-in inventory and the magnitude of the change in fluid temperature. In the riser section, two different scenarios can cause the locked-in fluid temperature to increase from its initial value (the seabed ambient temperature):

1. The riser inventory is subjected to the ambient temperature gradient that is found between the seabed and the sea-surface; and
2. The riser inventory is subjected to a seasonal variation in the temperature of the ambient sea water across its entire height.

The simulations performed considered operation during summer months since this presents a worst case.

The main conclusion drawn from the analysis performed was that the operating conditions simulated are challenging for the existing tie-in spool because of the low fluid/wall temperature downstream of the SSIV. The tie-in spool connecting the existing pipeline and the riser will comprise two different sections as shown in Figure 7-3. It is characterised by two different minimum design temperatures: -29°C for the new section (either side of the new SSIV location) and -20°C for the existing section connecting to the riser (approx. 120 m in length). Therefore the existing tie-in spool section presents a limiting design condition.

On issue of the study report, the requirement to replace of this spool was reviewed. The conclusion of this evaluation was that the existing spools will not be replaced for the following reasons:

- The PCCS pipeline operating philosophy was revised to require the riser to be pre-pressurised to 36 bara with N_2 preventing the existing spool's minimum design temperature of -20°C from being exceeded during a re-pressurisation of the riser. Depressurisation of the riser below 36 bara is therefore considered possible but very unlikely and can be managed operationally;
- A more detailed assessment of available metocean data was been performed. This indicated that the maximum change in seabed temperature is lower than the 7°C

originally assumed. As a result, it was concluded that the predicted thermal expansion can be accommodated within the MAIP (Maximum Allowable Inlet Pressure) for the pipeline and riser base spools since the likelihood of exceeding the MAIP is considered small. Also, there would be time for operator intervention to reduce pressure in the riser and/or pipeline;

- The risks to personnel due to additional diving works required to replace the existing spools at the riser base are considered to be higher than the risks as a result of thermal expansion causing the MAIP of the existing spools to be exceeded.

7.4.4. Injectivity Management

7.4.4.1. Gravel Pack and Formation Plugging – Filtration

Very small particles can be accepted in the injection wells without causing plugging at the gravel pack screens and formation. The recommended values for filtration are 17 microns to avoid plugging of the lower completion in the existing wells and 5 microns to avoid formation plugging. Formation plugging will lead to formation impairment and hence reduced CO_2 injectivity.

Since the Goldeneye platform produced hydrocarbons for seven years, it is considered likely that debris will be present in the existing 20-inch Goldeneye offshore pipeline (corrosion products, fines, etc). When flow is reversed in the pipeline, displacement of these products into the wells without any mitigation measures would plug the lower completion (screen-gravel pack) and the formation.

Mitigation options related to pipeline commissioning and filtration will therefore be applied to ensure long-term injectivity. The offshore pipeline will be cleaned during the commissioning phase of the Peterhead CCS project. Removal of the solids and liquids during pipeline commissioning phase is very important to ensure the long-term integrity of the offshore pipeline, the lower completion and formation.

Displacement of any pipeline content into the wells during the pipeline-commissioning phase must be avoided in order to preclude formation damage. To achieve this, 2 x 100 % filters will be installed on the Goldeneye offshore platform with specification of 5 microns, which will pick up any contaminants left in the pipeline after flushing. This proposal will be reviewed further during detailed design.

A hydrocarbon freeing operation was executed in May 2013 when 9 pigs were sent from the platform to the pipeline landfall at St Fergus. The sludge collected by the pigging exercise contained less than 1 kg of solids. The sample analysis indicated 12 % solids with 50 % water and 25 % condensate. The solids contained 50 % iron oxides and the rest acid insoluble compounds (silicates), carbon and other salts and trace materials. Sand was not detected. The only material expected but not present in the samples was Iron Carbonate ($FeCO_3$). Additionally there was no indication of significant internal coating loss. A risk-based inspection frequency for checking filters in the first year should be included in the inspection programme with sample testing to see if the coating is deteriorating. Following completion of the hydrocarbon freeing operation, analysis of samples obtained from the Goldeneye pipeline has confirmed the line is full of clean, chemically-treated water with acceptable OIW levels. No further interventions or chemical treatment are required for up to five years.

7.4.4.2. Disbondment of Pipeline Coating

The existing offshore pipeline was installed with an internal epoxy coating. The internal coating is a solvent-based cured epoxy. The thickness of the cured epoxy is between 30 - 80 microns.

Although coating disbondment is not expected, there is still some degree of uncertainty regarding the response of the coating to CO_2 exposure. Should disbondment occur during normal operation, then particles ranging from small solids to relatively large fractions of coating may be formed, which could subsequently clog or completely block the gravel pack/formation, thereby reducing injectivity. This risk will be mitigated by the operation of tight control of the quality of the injection product and the installation of an appropriate filtration system (particle removal specification to 5 microns) on the platform upstream of the wells. Again, injection gas quality management will feature in operational procedures that will be developed for the Peterhead CCS project.

Decompression testing was performed on a section of stock/spare goldeneye pipe in the warehouse with CO_2 content during the Longannet CCS Project's FEED study. Based on the decompression testing performed, it is considered unlikely that the coating will disbond even under very aggressive decompression rates with dense phase CO_2 (worse than will be seen in operation). Nevertheless, this does not remove the need for precautionary filtration. The soak time was minimum 30 days to ensure coating was fully saturated with dense phase CO_2 and taking into account decompression durations, the coating was actually exposed for about 40 days in total. The pipe tested during the Longannet FEED was taken from stock/spare holdings and therefore was not ideal in that the tests would have been more representative if a section of the actual Goldeneye pipeline could be retrieved. A repeat of the decompression test will be considered after tie-in of the new pipeline when a section of the existing Goldeneye pipeline will be removed and can therefore made available for testing.

7.4.4.3. Hydrates

The formation of CO_2 hydrates is possible when free water is present in sufficiently significant quantities and the temperature and pressure of the fluid is within the hydrate formation window. Provided that the stringent CO_2 dryness specification is achieved, hydrates should not form in the pipeline system during normal dense phase operation.

However, there is a risk of hydrate formation in the well tubing and near wellbore area. During previous hydrocarbon production, water has encroached into the Goldeneye gas cap and at least part of the well gravel pack will be surrounded by water at the time the CO_2 injection commences.

The cooling of the injection well and the surrounding reservoir matrix induced by the injection of CO_2 will have the potential to create conditions favourable for the formation of hydrates at or near the wellbore. This assessment is based upon the assumption that both formation water and hydrocarbon gas will be present initially in the well and the surrounding reservoir matrix.

In order to reduce the risk of hydrate formation during the initial years of injection (when water is present in or near the wellbore) it is considered prudent to introduce batch hydrate inhibition prior to start-up of a well for injection purposes. The injection of hydrate inhibitor can be stopped once the water is displaced from the wellbore. If water is subsequently introduced into a well and / or it is suspected that water is present in a wellbore due to a very long well shut-in period, then batch inhibitor injection should take place until the water is displaced away from the well once again.

Methanol is the selected hydrate inhibitor and this will be supplied to the platform via the existing 4-inch pipeline from St Fergus to Goldeneye. Batch injection of hydrate inhibitor will feature as an instruction in the well operational and start-up procedures that will be developed for the Peterhead CCS project.

8. Goldeneye Platform and St Fergus Methanol Works

The Goldeneye Platform Facilities shall be modified to accommodate their re-use for carbon storage as part of the PCCS project. The following sections describe the main scope for the design of the modifications.

8.1. Process Description

The offshore process is described in a Process Flow Scheme for the Goldeneye Topsides [52]. CO_2 arrives in the dense phase on the Goldeneye Platform. The CO_2 arrival pressure is in the range 90-115 barg topsides and the temperature range is between 2.3 ºC and 10.1 ºC. The composition limits are also described in a Process Flow Scheme [53]. The CO_2 is metered and filtered to remove particles greater than 5 micron before injection into the reservoir.

The CO_2 flows to an injection manifold where the flow can be directed to one or more wells. At the start of field life it is expected that all the captured CO_2 will be directed to a single well. Three existing wells will be recompleted for CO_2 injection and one will be recompleted for reservoir monitoring. Two of the injection wells will be designed for early field life injection and the other one for late field life injection when the reservoir pressure has increased. Initial injection will be into the reservoir matrix below the fracture pressure of the formation. Later on injection pressures may exceed the fracture pressure of the formation.

CO_2 will be injected into the reservoir in dense phase. Dense phase is maintained using velocity tubing. The velocity tubing provides the pressure gradient necessary to maintain CO_2 in dense phase. Down-hole control has been deemed impractical. This aspect of the well design imposes a minimum injection rate constraint on the system.

A minimum injection rate will be required to maintain the CO_2 in dense phase. Continuous injection of CO_2 at flows less than the minimum flow leads to chilling of the well below 0 ºC and, if sustained for long periods, threatens well integrity.

Operating procedures shall be developed in Detailed Design to ensure that injection wells operate within their operating envelope.

Facilities will be provided to inject methanol into the wells. Methanol will be delivered via the existing 4-inch (102 mm) pipeline from onshore and will be injected directly into the wellhead Christmas tree between the wing valve and upper master gate valves. Methanol is required to avoid or remove hydrate blockage from the injection tubing and formation. It is expected that injection of methanol will be mainly required as a temporary facility during the initial period of CO_2 injection until formation water is displaced or dissolved in the dense phase CO_2.

Methanol can also be used to balance the pressure across the SSSV before opening and also to bullhead the wells to mitigate the effects of high Closed-in Tubing Head Pressure (CITHP) should a light hydrocarbon gas column be trapped in well injection tubing.

Goldeneye will continue to operate as a Normally Unattended Installation (NUI) during CO_2 storage operations. To enable this, all day-to-day control shall be capable of operation from the Peterhead CCS control room. The control system and operation procedures shall be designed to minimise offshore visits.

8.2. Design Basis

8.2.1. CO_2 Flowrates

The three design cases, corresponding to the maximum design case, the normal operating case and the minimum turndown case, are detailed in the FEED Heat and Material Balances [22].

The topsides pipework shall be capable of future expansion to approximately double the PCCS design flowrate capacity.

8.2.2. Design Pressures and Temperatures

The design pressure of the CO_2 handling facilities is 213 barg with design temperatures of -80ºC /+50ºC.

The pipeline vent and process relief and vent system is designed to 213 barg and -100ºC /+50ºC to accommodate blockage and lower temperatures possible when CO_2 is released into the air. This is to eliminate the risk of overpressure of tail pipes due to blockage with solid CO_2 or ice.

The wellhead depressuring system re-utilises the existing platform vent system. This is rated at -100ºC /85ºC and 10 barg/FV.

The methanol system is rated at 240 barg and -8.2 ºC and 45 ºC. A change from the existing design pressure of 250 barg is required to accommodate a new 1500# 316 stainless steel filter and pipework.

8.2.3. CO_2 Filter Capacity

The CO_2 filtration has 2 x 100 % filters. The filters shall remove solids larger than 5 microns. This is to prevent the impairment of reservoir injectivity.

The filters will be designed for a nominal loading of 1 kg solids before change-out is required. It is not expected that significant quantities of solids will be produced from the pipeline.

To meet potential future needs, the pipework configuration shall allow the CO_2 filtration system to be converted to 2 x 50 % to handle 250 t/h by operating both filters vessels in parallel. The configuration is described in the Process Engineering Flow Scheme for the CO_2 Filters [54].

The CO_2 filters shall be operated as two separate trains with dedicated valves to control pipeline and filter back pressure downstream. Normally one filter will be kept on line and the spare will be kept pressurised with the back-pressure control valve on manual and closed. Operations shall have the ability to switch flow to the standby train remotely from Peterhead CCS Control Room in the event of excessive pressure drop across the duty filter.

8.2.4. Methanol Capacity

The methanol system will be designed for a nominal rate of 5 m^3/h. The methanol supply will have a single filter capable of removing particles greater than 5 microns. This is to prevent impairment of reservoir injectivity.

The solids loading of the filter will be based on a nominal loading of 1 kg.

8.3. Boundary Limits

The scope of the process design shall extend from the weld outboard of the riser ESDV to the Christmas Tree injection flanges. For the hydrate inhibitor system, the scope will cover the required modifications to the platform topsides to the injection wing valve on the Christmas Trees.

The scope for the topsides design is described in the following PFS:

- PFS Goldeneye Topsides Facilities for Carbon Storage [52]
- PFS Goldeneye General Utilities for Carbon Storage [55]
- PFS Goldeneye CO_2 Venting Systems [56]
- PFS Goldeneye Wellhead and Lubricator Vent System. [57]

8.4. Utilities

Goldeneye Utility systems are defined in the following UEFS:

- Utility Engineering Flow Scheme ZG Hydraulic Power System [58]
- Utility Engineering Flow Scheme Well Bleed off Manifold Arrangement [59]
- Utility Engineering Flow Scheme ZG Vent System [60]
- Utility Engineering Flow Scheme ZG Nitrogen System [61]
- Utility Engineering Flow Scheme ZG Drains System, T60010 [62]
- Utility Engineering Flow Scheme ZG Chemical Injection System for CCS Project [63]

Other utility systems such as the Diesel System, Freshwater Supply, Dry Firewater Ring-main, Domestic Drainage and Helideck Foam System will not be modified by the Project. These are described in existing as-built UEFS, which have not been included within this document.

8.4.1. Relief and Depressuring (System 50)

A number of new venting systems require to be provided on the Goldeneye Topsides to handle the requirement of dense phase CO_2 relief and venting. The PCCS FEED study has confirmed that there are no requirements for automatic blowdown. The risk of escalation following a small leak of CO_2 is low and a large leak would be released too quickly for emergency depressuring to be effective. Any benefits from an automatic blowdown system are outweighed by the additional risks of increased maintenance requirements on a NUI.

8.4.1.1. Pipeline Depressuring Vent

A vent system is required to depressurise the pipeline. This involves the disposal of up to 20,000 tonnes of CO_2. This process will take several weeks to allow liquid CO_2 to boil-off in the pipeline.

8.4.1.2. Well/Lubricator Vent

A system for venting high pressure gas from the wells shall be installed. This gas may contain hydrocarbons and CO_2. The high pressure vent system is required for:

a. Depressuring the well tubing above the subsurface safety valve for periodic integrity tests
b. Depressuring the lubricator during well work-over operations
c. Taking samples from the monitor well.
d. Relief of excess well pressure in the event of CITHP greater than 115 barg.

Samples from the monitor well will be required to monitor the migration of CO_2 at the monitor well bottom hole. This will be used to confirm reservoir models and validate surface measurements of CO_2 plume distribution.

The Goldeneye reservoir pressure is currently below hydrostatic. Over time, the reservoir pressure will increase as a result of aquifer influx and increase further due to the injection of CO_2. A light hydrocarbon column may be trapped in unused wells leading to closed-in-tubing head pressures greater than the CO_2 pressure available top hole. The primary means for reducing this pressure is expected to be achieved by methanol injection into the wellhead potentially assisted by depressuring the well above a closed SSSV.

A new system will be deployed, utilising the existing Vent KO vessel, vent stack and vent riser.

8.4.1.3. Thermal Relief Valve Vents

Blocked-in sections of topsides pipework can be potentially over-pressurised due to thermal expansion of dense phase CO_2. Relief valves shall be provided to protect these sections. These valves will be equipped with bursting disks upstream and pressure indicator alarms. Thermal Pressure Safety Valve, PSV discharges will be routed beneath the platform. Bursting discs are used to prevent leakage of CO_2 to the environment. The pressure alarm alerts the operators to a thermal relief event.

Small thermal relief valves will be required to protect smaller volumes such as valve body cavities. It is assumed that these will discharge locally.

8.4.1.4. Equipment Vents

Equipment such as CO_2 filters and pig receivers will require vents. The vented gas is discharged via individual vents beneath the Cellar Deck. Depressurisation for maintenance activities, e.g. filter change-out, shall take into account the depressuring times in relation to operability, taking CO_2 freeze-out into consideration.

Depressurisation of all equipment and pipework apart from the pig receiver is achieved by local vent valves. Depressuring of the pig receiver is achieved by automatic control. This can be controlled from the local control room reducing exposure of personnel to risks associated with pig trap chilling below lower design temperature. This situation may change following material review (see Section 11.5).

Double-block-and-bleed isolation is installed where required to allow positive isolation to be installed for maintenance. Vents shall be provided to bleed the gas between the valves. These must remain free of blockage with frozen CO_2.

8.4.2. Hydrate Inhibition (System 73)

Initial injection will involve the injection of cold dense-phase CO_2 into wells and sandstone matrix that will contain water and hydrocarbons. Down-hole conditions are in the hydrate regime during start-up so hydrates could plug the well and impair. Provision shall be made to inject hydrate inhibitor into the well to mitigate this problem. Existing facilities at St Fergus shall be modified to deliver methanol to the platform via the existing MEG and Corrosion inhibitor injection system and pipeline. Methanol will be filtered through a 1 x 100 % 1500# stainless steel filter located upstream of the methanol injection manifold. The filter will remove particles greater than 5 micron before injecting down-hole. Each well will require about 6 m^3 of methanol.

Methanol will also be provided to bullhead the wells to reduce CITHP if it becomes excessive due to light hydrocarbon gas column in the well tubing string. The design pressure of the methanol system will be reduced to 240 barg to allow a filter vessel to be deployed.

8.4.3. Diesel and Power generation (System 80)

The FEED design considered that no modifications to the existing diesel and power generation on the platform will be required for PCCS.

However, the diesel system including the diesel storage tank (crane pedestal) has been contaminated and shall be cleaned as part of the Contractor's scope during construction.

8.4.4. Hydraulic Systems (System 10/72)

The existing Goldeneye hydraulic power systems will be re-used for PCCS. These comprise one main Hydraulic Power Unit (HPU) and dedicated HPUs for each of the five wells installed for hydrocarbon production.

During Detailed Design, it will be necessary to review the existing HPU filters to ensure that they comply with the DEP v39 requirements and ensure an open flow return path is available from the spring return actuated valves to the HPU reservoirs. Where any filter is found non-compliant with the DEP, the existing filters will require to be replaced with compliant items.

The existing HPUs will be modified as part of the PCCS project to provide hydraulic fluid to all the new valves.

A new Topsides Umbilical Termination Unit (TUTU) will connect hydraulic hose and electrical signal lines in the umbilical for control and monitoring of the SSIV skid. Solenoids on the Goldeneye topsides main HPU, (ZG-HPU-72001) will control the SSIV and its bypass. The SSIV is a fail-closed valve whilst its by-pass has a 'stay-put' action.

Valves on Goldeneye are either hydraulically or electrically actuated. There is no provision for instrument air.

8.4.5. Hazardous Open Drains System (System 60)

The existing closed drain system will be isolated and decommissioned.

The hazardous open drain tank, (ZG-T-60010A), will be retained. The original design concept was for this tank to be removed to shore for disposal of drained fluid. However, Goldeneye operations have not followed this practice due to lifting restrictions. For FEED, it has been assumed that the current practice of decanting drained fluids to Intermediate Bulk Containers (IBC) using temporary pumps will be retained for PCCS operations and that no lifting of the drains tank will occur.

Layout constraints prevent the drainage of the methanol filter and vent knockout drum to the Hazardous Open Drains Tank (ZG-T-60010A). These will be drained to IBCs located close by using temporary hose. Nitrogen from the nitrogen system will be used to drive the liquid from the vessel.

8.4.6. Nitrogen System (System 59)

Nitrogen is required for the following:

a) Motive force to drive methanol from the filter to IBC via temporary hose during drainage operations;

b) Motive force to drive vent liquids from the vent knock out drum to IBC via temporary hose during drainage operations;

c) Dilution of CO_2 during venting of spools between double block and bleeds to prevent formation of solid CO_2;

d) Preservation of pig trap;

e) Equalisation across ESDV;

f) Equalisation across SSIV;

g) Well operations.

The existing nitrogen quad-based N_2 supply system shall be modified for re-use for PCCS. The extent of modifications is shown in the Utility Engineering Flow Scheme for the ZG Nitrogen

System [61]. The system shall have a high pressure supply with relief valve set at 213 barg and a lower pressure manifold with a design pressure of 10 bar. The high pressure supply will be controlled at 120 barg by a self-regulating control valve. This will also supply the low pressure supply that operates at 1 barg. The high pressure supply will be used mainly for dense phase CO_2 systems whereas the low pressure supply will be used for assisting drainage of the vent knock out drum and methanol filter.

Ad hoc requirements for large quantities of nitrogen for major maintenance and pigging operations shall be provided by temporary liquid nitrogen generation facilities together with helium for leak detection, if required.

8.4.7. Fire Fighting System (System 46)

Goldeneye does not have a permanent firewater system. A dry firewater ring-main with two firewater monitors located on the cellar deck is provided for use during drilling operations. The supply of firewater is provided from pumps on the jack-up drilling rig. Any modifications of this system required for PCCS operations will be performed by the drilling contractor.

8.5. Topside Layout

The plant layout provides the overall spatial arrangement of all process, utility and general facilities, and associated infrastructure within the plant boundary.

The plant layout shall be developed in such a way that all categories of risks (including HSSE-SP, technical, political, economic – cost and schedule, operational) are reduced to As Low As Reasonably Practicable (ALARP) during all phases of its life, from construction through to decommissioning, and shall ensure that the plant has been laid out such that it can be safely and efficiently operated and maintained.

The scope for offshore part of the project covers the modifications required to the Goldeneye Platform topsides to change from a production facility to a CO_2 reception and injection facility to enable the captured CO_2 to be permanently stored in the depleted Goldeneye reservoir and includes the following offshore scope:

- Destruct of existing pipework on Goldeneye to make room for new design;
- Installation of new CO_2 filters and Methanol Filters;
- Installation of new pipework including CO_2 injection manifold on Goldeneye.

It is also proposed to provide methanol to the Goldeneye platform from St Fergus by re-using the existing onshore glycol facilities at St Fergus and then transporting the methanol to Goldeneye via the existing 4-inch offshore pipeline.

The following project-specific design criteria were used at the outset of this project phase:

- The layout development shall only cover the new CO_2 reception facilities for the project. This includes new meters for CO_2 and Methanol, new CO_2 filters and their connection to the new Christmas Trees;
- New TUTU, valve HPU and a module with inbuilt HVAC housing new control panels are located for space allocation only. In the later stage of FEED it was agreed that the space is available in the existing valve HPU for the new SSIV and its bypass valve. However it would require additional space for two accumulators to support the subsea actuated valves on the pipeline;
- A space has been allocated for a new nitrogen quad which would be connected to the new and existing facilities using existing tubing. New tubing would be required for new users;

- All the equipment is to be located to suit existing area classification (Zone-1 and Zone-2). Existing Area classification Zone-2 shall be extended to cover the reuse of the existing Drain Tank (ZG-T-60010A);
- Hot work shall be required on the 20-inch (CL1500) existing pipeline riser to weld a new flange. This flange will be the Tie-in to install new topside pipeline sections up to the existing pig trap. There are existing flanged connections available for other tie-ins required for this project;
- There is a space allocation shown for future diesel coalescer.

The following assumptions, considerations and main decisions were raised and addressed pre-FEED and have influenced the layout development:

- The installation of the new equipment and pipework would take place after removal of the existing pipework including valves on cellar and mezzanine deck, MEG filter, Christmas trees, vent K.O drum pumps;
- Existing pig trap (ZG-A-20002), Vent K.O drum (ZG-V-50003) and Hazardous Open Drains Tank (ZG-T-60010A) would be reused for this project. The Production Separator (ZG-V-20010) is redundant. In order to minimise offshore destruct work scope it will be purged, flushed, isolated and will remain in-situ;
- The existing pig trap is a launcher and is axially moved in south direction to have a minor barrel of sufficient length to convert its use as a receiver;
- An attempt has been made for new lines to be routed following the existing route, especially for flow lines and main pipeline route. Due to the design requirement it was not possible to maintain the existing support locations hence the supports would be required at the new locations;
- It is assumed that there would be a requirement to complete a dimensional control survey for closing spools during Detailed Design;
- It is assumed that the valves and pipework associated with the existing system that is retained for this project are suitable for the service and design conditions. The valves and pipework of the existing vent knockout drum and hazardous open drain tank, tubing for nitrogen would be reused for this project;
- Except for the 20-inch welded tie-in on the riser, all the tie-ins are flanged. The 20-inch weld shall be a 'golden weld' to pipeline code PD8010 Part-2;
- The existing pedestal crane on Goldeneye has sufficient capacity to install new equipment to their identified location. Therefore the layout has been developed such that the existing platform crane can be used in conjunction with other mechanical handling aids to access the new equipment for maintenance and removal;
- The new equipment required for this project is located in Zone-2 area which is same as the existing area classification. Existing Area classification Zone-2 shall be extended to cover the reuse of the existing Drain Tank (ZG-T-60010A).

8.5.1. Layout description

8.5.1.1. General

The purpose of the 'PCCS Goldeneye Project' layout development is to find a suitable location for the new equipment. The FEED layout drawing that has been produced shows new equipment and associated pipework connected to the tie-ins on the existing process system. Piping routings are taken into consideration to ensure an optimum flow path of dense phase

CO_2 into the reservoir. This optimum flow of CO_2 will ensure minimum CO_2 inventory on the platform, and hence, will credit towards a design with associated risks ALARP.

The selected location for the equipment considered constructability, access for operability and maintainability.

The layout will be revisited in the next phase of the project, i.e. during Execute, once final sizes have been received from the selected vendor for the equipment required for this project taking into account safety, operability, maintainability, constructability and HFE.

A space allocation was made during FEED to install a module containing panels on the weather deck close to the helideck. There was no laser scan available for the helideck area during FEED. Should this module be required, the final layout would be checked with new laser scan data during the next phase of the project.

8.5.1.2. Existing Pig Trap

The existing pig trap (ZG-A-20002) is a launcher. It will be reused as a pig receiver in conjunction with a 2,227 mm long pup piece to suit a Rosen Intelligent Pig (3.5 metres long). The existing pig trap has been moved axially in the south direction to provide space for the pup piece. The new location of the pig trap does not encroach into the existing pig handling area; however the primary escape route behind the pig trap door has been modified locally to suit its new location.

Structural modification would be required to provide supports for the existing pig trap in a new location and to provide temporary clamped on type mono rail to facilitate installation in its new location complete with associated pipework.

8.5.1.3. CO_2 and Methanol filters

There are two CO_2 filters and one methanol filter located on the platform topsides. The dimensions considered in FEED are based on information received pre-FEED. The CO_2 filters are located on the Cellar deck north side of the existing redundant production separator (ZG-V-20010) complete with a dedicated access platform. The methanol filter is also located on the Cellar deck, north side of the Christmas Trees, where the existing MEG filter was originally located.

Structural modification would be required to provide supports for new filters and to provide a temporary clamped on type mono rail to facilitate installation of filters complete with associated pipework.

8.5.1.4. TUTU and HPU

A new TUTU is located on the cellar deck based on the dimension received from instruments. It is located on the existing support frame next to the existing TUTU.

A space for potential new valve HPU was allocated in the location that was originally allocated for future well HPUs. The future wells were never drilled during production life of the platform hence the space for their HPUs was available to install the new valve HPU. An alternative location was also explored to locate new HPU in place of the existing Atlantic Cromarty HPU on the north side of the SSA. However this option was rejected as this space is currently proposed to be used for one of the boat landing platforms for the 'walk to work' vessel required during the construction and installation phase of this project.

In the later stage of the FEED it was agreed that there is space available in the existing valve HPU for the new SSIV and its bypass valve (subject to vendor confirmation), and the requirement of new HPU will be deleted if vendor confirmation is received on the availability of space in the existing HPU. This option would require additional space in the vicinity of existing valve HPU for two 50-litre accumulators with dimensions 1000 mm (D) x 700 mm (W) x 2500 mm (H). There is no space available around the existing valve HPU hence the new accumulators are to be located at the location that was allocated for potential new well HPUs discussed earlier.

Structural modification would be required to provide supports for the TUTU and HPU and to provide a temporary clamped on type mono rail to facilitate their installation.

8.5.1.5. Nitrogen Quad

Nitrogen was supplied to the existing platform through a nitrogen quad hooked up to the users through tubing. The existing nitrogen quad was located in the pig handling area on the mezzanine deck. The requirement of nitrogen for this project is proposed to be met by a nitrogen quad with large number of cylinder (20 nos.).

The nitrogen would be required during pigging operations so the existing quad location cannot be re-used. Instead it will be relocated on the weather deck platform close to the pig handling area. This location provided a safe, operable, maintainable solution for the project without interfering with human factor and construction aspects of the design.

This nitrogen quad would be supplying nitrogen to the users utilising existing tubing runs and installing new tubing where required. No structural modification is required for the nitrogen quad.

8.5.1.6. Existing Vent Knock Out Drum

The existing Vent Knockout Drum (ZG-V-50003) is retained for this project to facilitate well blow down activity.

A pressure trip (PZA) and a nitrogen purge connections are added upstream of existing vent valve at Nozzle N6 through a new spool. There was no existing access platform designed for this vessel hence no access to the pressure trip. Consideration should be given to the accessibility of the PZA trip and the nitrogen purge isolation valve locations during Detailed Design.

There is an existing access/escape route designed around the vent knockout drum hence there is no change to the safety, operability, maintainability aspects of the original design. No structural modification is required for the vent knock out drum.

8.5.1.7. Diesel Coalescer

Early in the FEED study, a concern was raised on the cleanliness of the diesel supplied to existing diesel generators (3 nos.) through the diesel storage tank in the crane pedestal. A diesel coalescer was proposed in the design to supply clean diesel to the generators. A space allocation was made during FEED to install this on the cellar deck close to the existing generators, based on high level vendor information. The requirement for the coalescer shall be revisited during Detailed Design.

8.5.1.8. Drains

There is an existing Open Hazardous Drain Tank (ZG-T-60010A) serving the weather deck drain and the drain from the diesel sump tank. For this project there is a drainage requirement from the existing pig trap, methanol filter and existing vent KOD.

The methanol filter and vent KOD would be drained using temporary hoses and Intermediate Bulk Containers (IBC). IBCs would be located in the south-east lay down area on the cellar deck.

This approach was also followed to drain the existing hazardous drain tank to the IBCs located in the south-east laydown area on the cellar deck.

There is an existing access and escape route designed around the vent KOD, pig trap and methanol filter (located at the place of existing MEG filter) so there is no change to the safety, operability, maintainability aspect of the original design.

No structural modification is required for the drains system.

8.5.2. Tie-ins & Pipe Routings

8.5.2.1. Tie-Ins

The new equipment required for the project is connected to the existing piping system through the following tie-in points:

- TP-01: Tie-in on the existing CO_2 pipeline riser;
- TP-02: Tie-in on the existing vent knock out drum inlet nozzle N1;
- TP-03: Tie-in on the existing vent knock out drum vent nozzle N6;
- TP-04: Tie-in on the existing vent knock out drum nozzle N3;
  TP-05: Tie-in on the existing vent knock out drum drain line 3 inch (D50002-L13450X-E);
- TP-06 and TP-07: Tie-ins on the existing nitrogen distribution pipework/Tubing;
- TP-08 and TP-09: Tie-ins on the existing drain line to hazardous open drains tank;
- TP-10: Tie-in on the existing MEG supply pipeline (EZV-73002).

All the tie-ins are flanged except TP-01 where a hot work permit and welding habitat would be required for personal safety. This tie-in will involve welding of a 20-inch CS (A694 F65) (CL1500) flange overlaid with Inconel-625.

8.5.2.2. Pipe Routings

Pipe sizes which are larger than or equal to 2 inch have been modelled in the PDMS 3D model during the FEED phase of the project. Pipes are routed to minimise the length of piping between equipment and tie-in, ensuring availability of structure for pipe supports without obstructing the access ways, escape route and to facilitate safe operation and maintenance. All the pipe routings were checked with laser scan data completed during the definition phase of the Project.

There shall be a special consideration given to the flange joints in the methanol system to avoid accidental release of methanol. Equipment such as flange guards may be considered during detailed design to avoid escalation in the event of accidental release of methanol.

The CO_2 manifold is connected to Wells 1, 2 and 4; however, there is a provision on the injection manifold piping for two future connections to Wells 3 and 5. The existing pipe route on the well bay area has been followed for individual injection lines to utilise the existing support structure.

There is enough space left in the design for providing a thermal shield for the Christmas Trees to protect them from the scenario of a cold jet or a small leak from new ESDV on the CO_2 riser.

The layout for the well bay area was checked for taller Christmas Trees. It was confirmed that the taller Christmas Trees can be accommodated. However, the existing Christmas Tree access platform would require to be modified to provide access to the valves on the taller trees.

The FEED phase Process Engineering Flow Schemes show nitrogen tie-ins in the piping scope. The available laser scan data is not detailed enough to confirm the location of these tie-ins, but the scan confirms that the majority of the nitrogen pipe work is run in tubing. The final location of nitrogen tie-ins and modification to the existing tubing to supply users for this project would require a site survey in the Execute phase of the project.

Thermal relief valve outlet lines are routed away from spider deck steel and the platform.

Stress shape approval was carried out for main process pipework to ensure their routing is not introducing stresses higher than are allowed in ASME B31.3 but loadings were not checked on the equipment. A comprehensive stress analysis should be performed during Detailed Design to ensure stresses as well as loadings are within the allowable loading provided by the equipment vendors. The shape approval also includes the requirement for the vibration assessment as per DEP 31.38.01.31 App-17 which will be completed during the Execute phase.

8.6. Topside Structure and Substructure

As explained in Section 2.5.5 of the FEED study identified that there are no direct structural modifications required for the change in operation from gas production to CO_2 injection. As such the structural scope of work becomes one of verifying the structural integrity of the structure for the extended operating life and supporting the modifications required by the other engineering disciplines.

8.6.1. Re-validation of Previous Integrity Checks

The Goldeneye jacket and topsides were installed in 2003 with a design life of 20 years, although production was only expected to last about 7 to 10 years. During the FEED study the design life for CO_2 injection was established as 15 years, meaning the installation will remain functional up to 2038, extending the operating life to 35 years.

As part of the previous Longannet CCS FEED study, several studies were carried out to confirm the suitability of the Goldeneye asset for its proposed change of use. During this FEED study, it was necessary to review and re-validate the previous structural studies carried out so as to re-assess the structural integrity of the platform accounting for any changes in the design conditions and the extended design life.

The following points were addressed, with no significant issues identified:

- Revalidation of the of the In-Place analysis reports for both Sub-Structure and Topsides;
- Review of the additional accidental scenarios associated with CO_2;
- Review of the fatigue analyses of the Jacket;
- Review of the fatigue analysis on the Vent Stack on the Topsides;
- Review of design life extension assessment including review of past inspection reports/criteria, corrosion protection system and recommendations regarding future Structural Monitoring;
- Revalidation of overall weight implications with multi discipline inputs;
- Consideration of construction installation and handling routes.

8.7. Short Stay Accommodation Upgrade

The Short Stay Accommodation (SSA) on the Goldeneye platform shall be refurbished and upgraded to extend their design life for the 15 years required by the PCCS Project.

8.8. Methanol Facilities at St. Fergus

Existing St Fergus Goldeneye MEG facilities shall be modified for re-use to deliver methanol to Goldeneye. The proposed brownfield modifications are described in the project Process Engineering Flow Schemes and associated documentation. In general, the existing facilities are considered to be suitable for conversion to the proposed methanol duty. This will be confirmed during detailed design.

The main differences in function and scope are summarised below:

1) Methanol requirement is intermittent – only for well start-up. Simultaneous injection of methanol with CO_2 is not required;
2) Pure methanol will be used without corrosion inhibitor;
3) No methanol recovery is required as this is a once-through system with the methanol injected downhole into the wells;
4) The system design pressure will be reduced to 240 barg to accommodate a new 1500# stainless steel filter vessel offshore;
5) Small volumes of methanol (6 m^3/well start up) will be required;
6) Existing glycol pumps, (P-7704A and B), shall be modified and retained for methanol service;
7) Modifications to pump seals will be required. This will involve new drains from the seal labyrinths;
8) Replacement suction filters shall be provided as the existing filters are unsuitable for methanol use;
9) Pump discharge pipework will be modified to reposition high temperature trips between the pump discharge and the relief valve take-off;
10) The supply of methanol shall be taken from Glycol Holding Tank, (T-7703). This shall be re-designated as the Methanol Storage Tank. Pipework modifications will be required to route the methanol from Methanol Storage Tank, (T-7703) to the Methanol Pumping System;
11) PCCS will retain the Sump Vessel, (V-7704), and associated pumps, (P-7706 and (P-7708). The Sump Vessel, (V-7704), will require a new relief valve to accommodate increase fire relief loads from methanol. The existing flare system has been decommissioned. Sump relief valve and blanket discharges shall be disconnected from the flare and located to an elevated safe position;
12) A new emergency shut-down valve will be installed at the pipeline inlet to protect the facilities from back-flow of large volumes of methanol. A facility will also be installed to allow bleed-off of pressure from the methanol pipeline to avoid thermal overpressure from the pipeline when it is shut-in for long periods.

The facilities have been designed with a base case assumption that the rest of the Goldeneye facilities will remain redundant to St Fergus operations. However, other current Shell projects may require re-use of some facilities in future – which could mean that some of the design decisions made for PCCS need to be revisited.

8.9. Layout (St. Fergus Methanol scope- Onshore)

The plant layout provides the overall spatial arrangement of all process, utility and general facilities, and associated infrastructure within the plant boundary.

The plant layout shall be developed in such a way that all categories of risks (including HSSE-SP, technical, political, economic – cost and schedule, operational) are reduced to As Low As Reasonably Practicable (ALARP) during all phases of its life, from construction through to decommissioning, and shall ensure that the plant has been laid out such that it can be safely and efficiently operated and maintained.

The scope for this part of the project covers the modifications required to the Goldeneye Module at the St Fergus plant to change from a MEG facility to a methanol reception and injection facility supplying methanol to the wells at Goldeneye:

- Destruct of existing pipework on Goldeneye module St. Fergus Plant to make room for new design;
- Installation of new Methanol Filters;
- Installation of new pipework.

The following project specific design criteria were used at the outset of FEED:

- The layout development shall only cover the minor modifications to the existing glycol injection facility to install new Methanol Filters (S-7706A/B), modify the piping for Tank (T-7703), Sump Vessel (V-7704) and Injection Pumps (P-7704A/B);
- New filters would be located to suit existing area classification;
- Hot work shall be required on the 4-inch (CL150) existing nitrogen supply to isolate the nitrogen supply to the existing flare header by installing a weld neck flange complete with blind flange. There are existing flanged connections available for other tie-ins required for this project;

The following assumptions, considerations and main decisions were raised and addressed pre-FEED and have influenced the layout development:

- The existing Tank (T-7703), Sump Vessel (V-7704) and Injection Pumps (P-7704A/B) would be retained for this project complete with existing piping except where modification is required to meet the design requirements for this project;
- It is assumed that the valves and pipework associated with the existing system that is retained for this project are suitable for the service and design conditions. The valves suitability for the methanol service is discussed in the Section 11.6;
- The existing layout access and lifting arrangement would be used for this project. The existing lifting arrangement would be used for mechanical handling to access the new equipment for maintenance and removal;
- It is assumed that the nitrogen and instrument air header required/retained for this project in the Goldeneye module pipe rack would be supplied from existing facilities.

8.9.1. Layout description

The purpose of the 'PCCS St Fergus Methanol project' layout development is to record piping modifications required to the existing glycol facility at Goldeneye module at St Fergus considering mechanical handling requirements, safety, operability, maintainability, human factors, constructability and any further considerations for next phase of the project.

The layout produced shows two new methanol filters and their connection to the existing pipework through tie-ins; modifications to the existing injection pump suction and discharge lines; modification to existing tank (T-7703) fill line, outlet line and conversion of its dip hatch nozzle to re-route injection pump re-cycle line to this tank; and modification to the Sump Vessel (V-7704) PZV outlet and nitrogen supply line. Piping routes are taken into consideration to ensure an optimum flow path of methanol into the reservoir. This optimum flow of methanol will ensure minimum inventory in the pipe & equipment, and hence, will credit towards a design with associated risks that are ALARP.

The layout will be revisited in Detailed Design, once final sizes have been received from the selected vendor for the equipment required for this project taking into account safety, operability, maintainability, constructability and HFE.

8.9.2. Tie-ins & Pipe Routes

8.9.2.1. Tie-Ins

The piping tie-ins are identified to facilitate connection of new equipment to the existing systems, re-use of existing piping/equipment for new modifications and isolation of the existing piping/equipment not required for this project. The details of these tie-ins are available in the Tie-In Schedule document [64] developed during the FEED phase of the project.

All the tie-ins are flanged except TP-33 where hot work and habitat for personal safety would be required. This tie-in will involve welding of a 4-inch CS (CL150) flange. This tie-in would be used to isolate the flare header after disconnecting its nitrogen purge line.

8.9.2.2. Pipe Routings

Pipe sizes greater than or equal to 2-inch were modelled in the PDMS 3D model during FEED. Pipes are routed to minimise the length of piping between equipment and tie-in, ensuring availability of structure for pipe supports without obstructing the access ways, escape route and to facilitate safe operation and maintenance. All the pipe routings are checked with laser scan data.

An attempt has been made for new lines to be routed following the existing pipe route to avoid support requirement on the paved area.

Stress shape approval was carried out for main process pipework to ensure their routing is not introducing stresses higher than allowed as per ASME B31.3 but loadings were not checked on the equipment. This project is a minor modification to the existing system hence formal stress analysis may not be required as per ASME B31.3 sec.319.4.1 except for injection pump recycles line. A comprehensive stress analysis will be performed during Detail Design to ensure stress as well as loading are within the allowable loading supplied by the equipment vendor. The shape approval also includes the requirement of the vibration assessment as per DEP 31.38.01.31 App-17 to be completed during the Execute phase.

9. Wells and Completions

This section highlights the Wells requirements relevant for inclusion in the overall PCCS project Basis for Design and application to the surface facilities for Peterhead CCS project. It is not intended to cover comprehensively the requirements for design of the injection wells for the Project which is covered in other Wells specific documents.

9.1. Description

There are five wells in the Goldeneye platform initially drilled and completed to produce hydrocarbons. The abbreviated well names are used in this document.

Table 9-1: Existing production wells

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

The field was granted Cessation of Production (CoP) from the Department of Energy and Climate Change (DECC) in Q1 2011. All Goldeneye wells were suspended with mechanical plugs during 2012/13.

The current plan is to recomplete four of the five existing production wells by means of a workover – replacing the upper completion. There are still three spare slots available but there is no intention to drill any new wells for injection, appraisal or monitoring purposes. Three of the four re-completed wells will be used for CO_2 injection. The fourth well will be used as a monitoring well with the option of using this well later for injection purposes if required.

9.2. Design Basis

For CO_2 injection, re-completion of the wells is a necessity. This will include replacement of the upper completion. The reasons for this are:

- There is a risk of unlatching the Polished-Bore Receptacle (PBR), due to cooling of the tubing string, allowing CO_2 to enter the 'A' annulus forming Carbonic acid which may corrode the carbon steel production casing;
- The tubing must be designed to create a pressure drop to keep the injected CO_2 in the dense phase during injection, thereby minimising exposure to low temperatures and dynamic loading due to two-phase flow of the tubing during injection;
- Some of the current completion components present integrity issues at the SSSV level.

The Goldeneye wells were gravel-packed for hydrocarbon production due to the prediction of sand failure under production conditions using Goldeneye rock mechanics information. No sand production was reported in any of the wells during the production phase, indicating that the installation of the gravel pack has been effective in controlling sand failure and/or that sand failure had not taken place.

The main functional requirements for the injection wells in the Peterhead Goldeneye CCS project are:

- CO_2 expansion properties (phase behaviour) are managed by small diameter tubing resulting in temperatures compatible with the materials in the existing wells;

- The upper completions and wellhead must be designed to withstand transient low temperatures occurring during low-pressure operation of the well particularly during start-up and shutdown;
- All well completion materials should be compatible with the injected fluid and expected pressures and temperatures. Oxygen needs to be controlled below 1 ppmv (now relaxed to 5 ppmv) in the CO_2 to avoid integrity issues in the lower completion and tubing;
- A particle size limitation of 5 microns in the injection fluid to avoid plugging of the screens and reservoir and maintain injectivity during the life cycle of the well;
- The injector wells need to be able to cope with a range of CO_2 arrival rates within the limits of the capture plant;
- The wells will have specialised equipment to monitor the CO_2 injection process such as permanent down-hole gauges. There will also be distributed temperature and acoustic sensing based on fibre-optic technology, which provides advantages in terms of performance and reliability.

9.3. Boundary Limits

The well design considers the well elements from the Christmas tree down to the formation.

The current Christmas tree (API 6A class 'U') and tubing hanger is rated to -18°C. This will be replaced with lower temperature rated equipment (class 'K' i.e. -60°C).

The wellhead will remain in place and has a limitation to -18°C. This casing hanger is not in contact with the CO_2 but in metal to metal contact with the tubing hanger.

Due to the potential cooling in the top part of the well under an uncontrolled release of CO_2 scenario the tubing down to the subsurface safety valve (SSSV) will be replaced by S13Cr tubing material. Below the SSSV 13Cr material will be utilised.

Currently available SSSVs are rated to -7°C, under certain unlikely scenarios the SSSV may be exposed to temperatures below the current design rating. Further development in this area is ongoing with identified preferred suppliers.

The 'A' annulus fluid will also be selected with a suitably low freezing point and will be installed with a nitrogen cushion to avoid fluctuations in the annulus pressure/fluid levels with changing temperatures.

The lower completion (screen + gravel pack) is to remain in place.

9.4. Workover Activity

To workover the wells a heavy-duty jack-up rig will be placed over the platform similar to the rig originally used to drill the wells in 2003. All the activities necessary to workover the four wells and abandon/isolate the reservoir section of the fifth well will be carried out from the rig. This is currently estimated to take around 150 days.

9.5. Utilities

The Christmas Tree valves such as the Upper Master Gate Valve (UMV) and Flow Wing Valve (FWV) are controlled via hydraulic actuators, the MHW actuators. These have a crack pressure around 3,350 psi (231 bar) and hold open pressure of around 2,500 psi (172 bar), and the volume swept is generally in the region of 2.36 litres. The hydraulic operating fluid will be defined in the detailed engineering phase. In addition to this hydraulic power shall also be required to operate the downhole safety valve.

The permanent downhole gauges and Distributed Temperature Sensing (DTS), which is deployed for a monitoring, characterising and integrity evaluation function, will require surface cabling from the well bay area to the local control room where they will be connected to WellWatcher Arconn and DTS ultra-units respectively. These surface units allow the acquisition of the downhole data and if required can even store the data for a given timeframe, the duration varies depending on the resolution, number of sensing points selected and frequency at which the unit is commanded to interrogate.

All the components of this data acquisition cabinet, generally comprising of a WellWatcher Arconn, WellWatcher Ultra, PC, RTAC PC and monitor, are powered via a dedicated UPS which operates at 100-240 VAC 45-65 Hz.

Power will also be required for additional sensors defined in the well and reservoir surveillance strategy. This shall include surface pressure and temperature sensors installed on each well to monitor A, B and C annulus and control lines. Additional temperature and pressure sensors shall also be incorporated in the individual well flow meters to monitor injection rates.

In order to measure accumulation and migration of gas clouds detectors using the IR absorption and line-of-sight techniques shall be incorporated.

9.6. Tie-ins

The opening and closing of wells shall be controlled from the Peterhead CCS control room onshore via motorised chokes connected to the production wing valve on the Christmas Tree. The flow rate will be monitored by flow meters installed on each individual flowline and these flow meters will be used for allocation purpose.

Three of the wells will be connected to the CO_2 supply manifold, whilst provision will be kept for the fourth well (monitoring well) to be connected at a later stage.

In order to protect the well components from extreme cooling, a protection system is to be incorporated to prevent prolonged CO_2 injection in the well under two phase conditions. In addition to this a pressure control valve will be installed on the depressurising vent system.

Methanol supply is also to be connected to the well via the kill wing valve, to be used for hydrate batch inhibition, SSSV equalisation etc.

Fibre optic and electric power cables are to be connected from wellbay area to the local control room to allow for downhole pressure and temperature gauges, DTS and DAS data communication.

Hydraulic fluid supply is required to operate the tree valves and downhole SSSV.

9.7. Wells Data

Integrity monitoring of the well will form part of the planned inspection regime for the wells. To facilitate this monitoring, the following data gathering and dissemination will be realised.

Surface pressure and temperature sensors for the tubing and well annuli will be installed and data transmitted live to the PCCS Control Room and also the Shell Tullos office.

There is also a requirement to transmit live the pressure/temperature of the SSSV system. In-well monitoring related to Permanent Downhole Gauges (PDG), Distributed Temperature Sensor (DTS) and Distributed Acoustic Sensors (DAS) will be installed in the wells.

Data from the PDGs and DTS will be transmitted live. The DAS data needs to be stored on the platform due to the very large amount of data. The plan with the DAS is to have data storage capacity on the platform which can be recovered and downloaded during the regular visits to the platform by the Operations group – scheduled to take place every 2 to 3 months.

Data from the gauges and DTS is required in the Shell Tullos office and for visualisation by the operator at the Peterhead CCS control room. It is also required to be able to control remotely some of the features such as sample rate and spatial resolution of the DTS measurements.

It is intended to retrieve the DAS data manually however there is a requirement to check the status of the communication and quality of data being acquired by the surface units. It is also planned to have some of the computing of the DAS data to be carried out on the platform via computers in the local control room.

The local control room space availability, power and bandwidth requirement has been reviewed and measures are in place to ensure these meet the needs of the project.

The summary of Well Surveillance Plan is provided below:

Table 9-2: Summary of Well Surveillance Plan

Activity	Frequency
Tubing Head Pressure (THP)	Continuous
Tubing Head Temperature (THT)	Continuous
SSSV system Pressure and Temperature Monitoring	Continuous
Annuli pressure monitoring	Continuous
Injection Flow Rate	Continuous
Permanent Down-hole Gauges (PDGs)	Continuous
Temperature Measurement along well bore with Distributed Temperature Sensors (DTS)	Continuous
Distributed Acoustic System	Continuous with data storage on the platform
Subsurface Safety Valve (SSSV) test	6-monthly – to be confirmed
Well Integrity Tests (WITs) including Christmas Tree Valves	Annual
Non-flow wetted Valves (SITs)	Bi-annually
Well sampling	Sporadic
Saturation profile	Sporadic – well intervention
Corrosion monitoring – caliper logs	Variable frequency with time – wireline intervention

GYA03 is planned to be the monitoring well and it will monitor temperature and pressure in the Goldeneye reservoir. It will determine the CO_2 injection front arrival time in this well in order to allow calibration of the reservoir model. The well is the most north-westerly well and is nearest to the structural spill point.

9.8. Closed-in Tubing Head Pressure (CITHP)

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 exist:

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

The wells will be designed to accommodate water, CO_2 and 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 bar) at the maximum predicted reservoir pressure of around 260 bar.

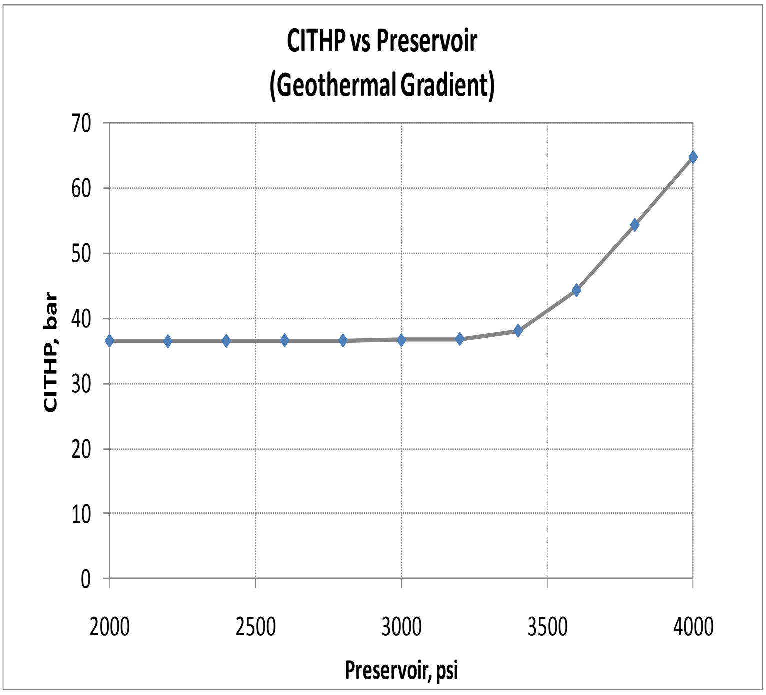

Figure 9-1: CITHP for a well filled with CO_2

In case 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 bar (assuming methane filling the tubing), see Figure 9-2.

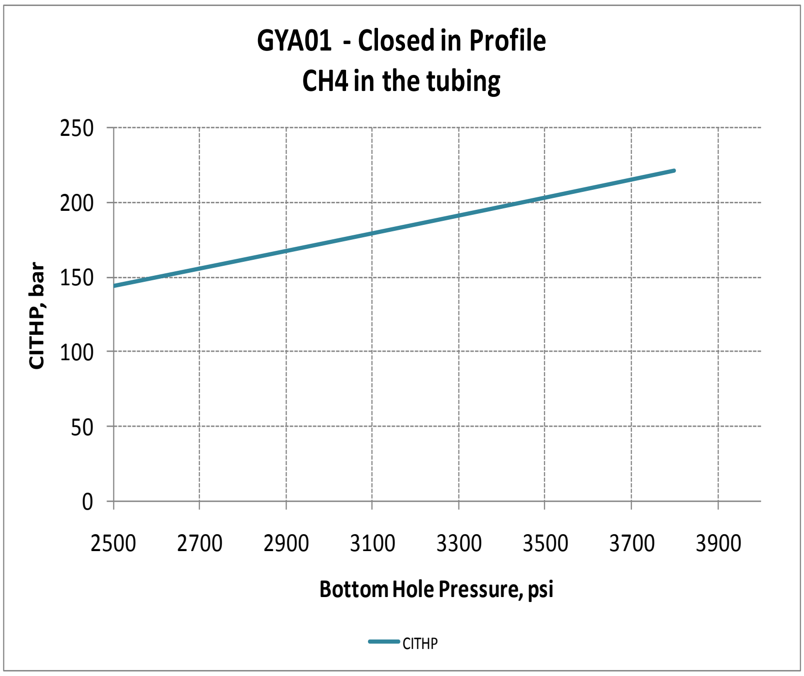

Figure 9-2: CITHP for a Well with Methane in the Tubing

The tubing will be left with water/brine and a nitrogen cushion in the top of the well after the commissioning/workover operations.

If the wells are filled with hydrocarbon gas then CO_2 cannot be injected in the wells due to the higher CITHP than the available CO_2 pressure. Under this scenario the wellhead pressure will be above 170 bar (up to 200 bar when reservoir pressure is 240 bar). The CO_2 available pressure is only 120 bar.

For these conditions it is proposed to displace methanol inside the well to reduce the wellhead pressure below 120 bar. Once the wellhead pressure is reduced to levels below the available pressure of the CO_2 , normal CO_2 injection can re-commence.

9.9. Hydrate Management

To reduce the risk of hydrate deposition it is proposed to displace methanol as hydrate inhibitor between the SSSV and the Christmas Tree prior to operational opening of a well for injection purposes while the well is closed in. Continuous methanol injection is not recommended.

The volume of methanol to be displaced in the well when the well is closed in is calculated to be 6 m^3.

9.10. Filtration Requirement

There is a likelihood that following seven years of hydrocarbon production, some debris will exist in the offshore pipeline (corrosion products, sand etc.). When flow is reversed in the pipeline for CO_2 injection service, displacement of these products into the wells without any mitigation measures could plug the lower completions (screen-gravel pack) and the formation. Plugging may reduce the injectivity through the lower completion (screens/gravel) and formation with time. Mitigation options related to pipeline commissioning and filtration will therefore be applied to ensure long term injectivity.

The risk of plugging the lower completion and formation rock with fines from the offshore pipeline (residual material after cleaning or from potential de-lamination of an internal coating) is mitigated by the installation of a filtration package on the platform. The maximum acceptable particulate size for the Goldeneye CO_2 injection wells is 5 microns.

9.11. Minimum Flow

The preferred method of managing the potentially extremely low temperatures in the well during injection is to maintain the CO_2 stream in liquid phase at the wellhead by keeping the required injection wellhead pressure above the saturation line. This will be achieved by creating extra pressure drop in the well by utilising small diameter tubing, thus creating back pressure through friction loss.

In order to manage the phase behaviour of the CO_2 and avoid integrity problems in the wells created by freezing, each well will have a limitation in terms of minimum rate dictated by a minimum of 50 bar of wellhead pressure. The maximum rate of a well will be dictated by the maximum available injection pressure, estimated at 115 bar at the wellhead dictated by the maximum allowable operating pressure of the offshore pipeline.

Although the CCCC train will be planned to be operated at a constant rate for most of the time, the injection system is required to be able to handle varying CO_2 rates from the capture plant. The wells will therefore feature completions designed for a specific range of minimum and maximum flow rates (across a range of potential reservoir pressures). At any flow rate one or two out of the available wells will then be called upon to provide the required injection at the desired surface and then current subsurface pressures.

The combination of injector wells should be able to manage any rate between the minimum and the maximum rates of the capture plant.

Frequent opening-up and closing-in (cycling) events should be avoided to limit the stresses in the well caused by temperature reduction during short periods of time.

During prolonged two phase CO_2 injection (stuck choke), it is possible for the top portion of the well to encounter low temperatures around -23°C. With increasing reservoir pressure this effect is diminished. A surface trip system will be installed to protect the well components from reaching these low temperatures for a prolonged time (>2 h).

The minimum wellhead pressure to avoid CO_2 existing in two phases has been determined to be 50 bar, taking into account the arrival temperature of the CO_2 at the platform.

No friction means that the CO_2 will be at the saturation conditions in the top of the well when the reservoir is depleted. This is valid during the well close-in and well start-up operations (transients). Low temperature is observed in the top of the well for a short period of time.

Strict operation procedures should be followed during close-in, start-up operations to avoid low temperatures. The closing in and opening up of the wells should be performed preferentially in an automated manner.

9.12. Wells Intervention Requirements (Venting)

Well interventions and integrity tests are planned during the life of the Goldeneye CCS as follows.

Table 9-3: Well Intervention Plan

Type of Activity	Frequency
Subsurface Safety Valve (SSSV) test	6 monthly (possible extended to once every 2 years)

Type of Activity	Frequency
Well Integrity Tests (WITs) including Christmas Tree Valves and wellhead valves	Annual
Non-flow wetted Valves (SITs)	Bi-annually
Well sampling	As per MMV plan
Saturation profile	As per MMV plan
Corrosion monitoring – caliper logs	As per MMV plan
Temperature logs	As per MMV plan

There is a requirement to vent high pressure gas from the wells. This gas of relatively small volumes may contain hydrocarbons and CO_2. This is required for:

- Depressuring the lubricator during wireline well operations;
- Depressuring the well tubing above the subsurface safety valve for inflow testing.

Bleeding off the tubing pressure for SSSV testing should be done in a controlled manner. A pressure control valve in the depressurisation system will allow for this operation to be carried out safely and efficiently.

10. Reservoir Engineering

The discussion here is provided for overview only, emphasising issues that could have an impact on surface facilities design.

10.1. Description

The CO_2 will be injected into the storage site at a depth >2516 m (8255 ft) below sea level into the high quality Captain Sandstone – present in a 130 km long and <10 km wide ribbon of Lower Cretaceous turbiditic sandstone fringing the southern margin of the South Halibut Shelf, from UKCS Block 13/23 to Block 21/2. At the Goldeneye field this sandstone has permeability of between 700 and 1500 mD.

Since 2004, the field has produced over 556 Bscf (15.7×10^9 Sm^3) of gas and over 22 MMbbl (3.5mln m^3) condensate. During production the field experienced moderate to strong aquifer support – which also served to end the production from the wells as each well sequentially cut water.

The primary CO_2 storage mechanism will be accommodation in the pore space originally occupied by the production of gas and condensate from the Goldeneye field.

Vertical containment is provided by the 300 m thick storage seal, a package including part of the Upper Valhall Formation, Rødby Formation, Hidra Formation and the Plenus Marl Bed. The sealing capacity of the Rødby Formation is considered to be excellent as it acts as the primary seal for all fields in the Captain fairway.

Three of the five production wells in the Goldeneye field will be converted to injection wells and one will be used for monitoring. At the start of field life it is expected that all the captured CO_2

will be directed to one well at a time. The injector wells are designed to have overlapping envelops to capture the range of capture plan during the lifecycle of the project. Injection will take place initially in a single well. At late life (~10 years after injection initiates), two wells are required to inject. No new wells are planned for CO_2 injection in Goldeneye.

Injectivity into the Goldeneye reservoir is anticipated to be high only requiring an injection pressure in the order of 200-250 psi (14 – 17 bar) above the reservoir pressure. Initial injection period will likely be in matrix conditions fracturing conditions even considering the injection of cold CO_2. Fracturing conditions might be encountered at the end of the CO_2 injection once the reservoir pressure increases.

10.2. Design Parameters

The current reservoir pressure and temperature is estimated at 2716 psia (187 bara) and 83°C (January, 2015 at datum of 8400 ft (2560m) TVDss) based on permanent downhole gauge information.

A sea-floor subsidence level of 4.6 cm was estimated for the hydrocarbon production phase (depletion). Due to the increase in the reservoir pressure due to the aquifer support and the CO_2 injection it is estimated that sea-floor will be lifted by 3.6 cm. The subsidence at the top of the Captain E&D sands after the gas depletion is 8.9 cm; the injection will cause an uplift of 3.3 cm resulting in a net subsidence of 5.6 cm after depletion and injection. Unfortunately these numbers could not be quantified as no subsidence information is available.

The integrity of the reservoir rock (Captain D) is preserved during the CO_2 injection based on geomechanic lab analysis of saturated CO_2 brine on the mechanical properties of the Captain sandstone.

10.3. Boundary Limits

The total injection volume must not exceed 25 Mt unless a new risk assessment has been performed.

The injection pressure must not exceed 5800 psi (400 bar) at bottom hole under isothermal conditions with no safety factor. Considering the difference in temperature between the injected CO_2 and the reservoir temperature then the maximum pressure should not exceed 4860 psi (335 bar) with no safety factor. Considering a safety factor of 90 % then the maximum bottom hole injection pressure should not exceed 4370 psi (301 bar) unless a new risk assessment is performed.

10.4. Risks

The main reservoir risks are the following:

1) The caprock is fractured by injection pressure. This should be mitigated by an alarm set on the bottom hole injection pressure. The MMV plan is designed to monitor for this.
2) CO_2 migrates past the spill point. The limit on the cumulative injection volume is the main mitigation against this risk. This is also guarded against by the monitoring activities.
3) Vertical CO_2/hydrocarbon flow migration to surface.
4) Back production of water into the wells. This will take place on well shut-in. Therefore it is necessary to ensure that the well materials can resist saline formation and carbonated formation water.
5) Hydrocarbon flow into an open well. If a well is allowed to produce to surface hydrocarbons (gas plus condensate) can flow to surface. The vent system for the well bay has been designed with this in mind. Gas detection must always be present. This is still a live gas/condensate field.

10.5. Pressure Evolution

The Goldeneye field is hydraulically connected to the neighbouring fields in the east (Hannay; Hoylake; and Rochelle) and the west (the now depleted Atlantic & Cromarty fields; and the still producing Blake).

The pressure support from the Captain aquifer has limited the decline in Goldeneye pressure, from an original of 3800 psia (262 bara) to a little under 2100 psi (at datum level of 2560 m (8400 ft) TVDss).

The wells are currently closed-in and the reservoir pressure is building-up. The current pressure (at Jan 2015) is 2716 psia (187 bara) based on downhole information.

If injection starts in 2019, the injection of 15 million tonnes of CO_2 is calculated to raise the pressure to 3595 psia (248 bara) at the end of injection. The pressure will then fall to 3470 psia (239 bara) ten years after injection ceases as it dissipates into the aquifer. The fall off will alter to no or a slow recharge, dependent on the activity of other fields in the Captain sandstone aquifer and on the degree of connectivity 120 km up dip where it is thought to ultimately outcrop at seabed.

10.6. Monitoring

Reservoir samples and logs will be taken at specific intervals in the wells. This will require well access for wireline crews on the platform.

Permanent Downhole Gauges in the wells will be used for pressure monitoring of the reservoir.

One existing well will be used as a monitoring well to determine the CO_2 breakthrough in the well and to monitor reservoir pressure to be able to calibrate the reservoir models. Depending on technology development there might be a possibility that the completion of this well will differ from the other injector wells.

10.7. Reservoir Data

Type	Sandstone – Captain D (main) and E Top of the reservoir 8255-8387ft (2516-2556m) TVDss
Formation temperature	~83°C at 8400ft (2560m) TVDss Reduction of temperature around the injectors due to cold CO_2 injection (~17-35°C bottom hole injection temperature). Reference Case 20°C bottom hole injection temperature
Average reservoir (Captain D) porosity and permeability	~25% porosity / 790 mD permeability

10.8. Fluid Compositions

It is important to note that zero back production is planned. It is also important to note that methane could displace the well contents in any well creating higher surface pressures and potentially creating an injection challenge. This section gives details of the fluids that could be produced in an upset condition (when the wellhead pressure is higher than the manifold pressure and the isolation valves are not closed. The volume will depend on the duration and the differential pressure) or during wireline and well operations.

There are five fluids involved:

- Injected CO_2
- Goldeneye hydrocarbons
- Aquifer water (and carbonated aquifer water)
- Injection methanol that might be back produced
- Dilute perfluorocarbons (PFC) tracer (ppb levels) that might be back produced

Formation Fluid	Gas - Condensate 0.37% mol CO_2 0% H_2S No solids production observed in the facilities There was a thin (7 m) oil rim in the reservoir at original conditions
Formation Water	Present in the wellbore at the moment of the workover Water will be initially at the sand face. Water breakthrough observed in all wells during the production phase. Salinity: ~56000 ppm TDS (52000 ppm NaCl) Water level in the wells is currently not known. It is expected to have more water in the wells at the workover time due to aquifer presence.

11. Material Selection

11.1. General

Materials selection for Peterhead CCS project covers assessment of the proposed systems for the following facilities:

- Capture of flue gas from Peterhead Power Station HRSG into pre-treatment sections of the Carbon Capture Plant (U-1000);
- CO_2 Capture Plant including the CO_2 Absorber and CO_2 Stripper (U-2000);
- CO_2 Compression and Conditioning including dehydration/O_2 removal within the Compression & Conditioning Plant (U-3000);
- CO_2 export through the existing Goldeneye pipeline to Goldeneye Offshore Platform;
- CO_2 injection/storage into existing Goldeneye wells; and
- Methanol supply from St Fergus to Goldeneye Platform

The power plant facility has not been included in the material selection assessment as it is not exposed to any of the products from the novel CCP and is therefore considered to be 'business as usual' for the power plant systems.

Following on from materials selection during pre-FEED the materials selection engineering for FEED has been covered by three separate reports for onshore CCCC plant, subsea and offshore scopes to comply with Shell's contracting strategy. Each report details updated materials selection to reflect finalised process conditions including transients, and equipment/piping design.

The design basis and detailed materials selection summary for each scope are covered in separate sections of this document. Section 11.3 is relevant to onshore capture, compression and conditioning. The PCCS CO_2 pipeline onshore section and offshore (new and existing) are reviewed in Section 11.4 and the Offshore Goldeneye modifications including CO_2 injection well materials are discussed in Section 11.5.

11.2. Material Selection Consideration

CO_2 capture technology based on flue gas produced from Peterhead power station and pipeline transportation to Goldeneye offshore platform for disposal into depleted hydrocarbon reservoirs for storage has presented key challenges for materials selection of onshore, pipeline and offshore systems including:

- Nature of the proprietary amine used for CO_2 capture and presence of degradation products. Therefore the project has selected stainless steel and concrete liner for most of the Carbon Capture Plant in contact with the circulating amine;
- Internal corrosion of carbon steel and suitability of corrosion resistant alloys due primarily to high levels CO_2 (4 mol % Flue gas→99.98 mol % treated gas);
- Low temperature carbon steel and stainless steel resistance to brittle fracture and ductile fracture propagation risks as a consequence of dense phase CO_2 decompression;
- Compatibility of non-metallic elastomers and polymers for valve/equipment seals in dry and wet dense phase applications, including low and high temperature performance;
- Suitability of existing Goldeneye subsea pipeline including internal epoxy coating.

Following capture, the CO_2 gas is compressed to dense phase regime and transported via pipeline to offshore topsides facilities.

For Peterhead CCS the Goldeneye pipeline, topsides and wells are existing facilities. PCCS FEED has confirmed all new materials have been selected as corrosion resistant, or that measures have been taken to treat exported gas and mitigate corrosion risk (e.g. corrosion inhibition or dehydration) in all retained existing materials. Materials selection considerations are complicated by use of both new and existing plant, equipment and facilities where evaluation for change in service, life extension and re-rating has been required.

CO_2 dense phase transport presents characteristic low temperature risks when depressurising pipelines and piping. Due to the decompression behaviour, process temperatures down to -56°C (CO_2 triple point) are feasible during uncontrolled (e.g. leak) depressurisation presenting a risk of brittle fracture and/or ductile fracture propagation. Therefore materials have been specified for adequate low temperature toughness, resistance to ductile fracture propagation or process control measures introduced to avoid rapid depressurisation.

There are specific degradation threats posed to non-metallic materials in the pipeline and offshore topsides piping systems. In particular for valves and equipment where elastomeric and polymer seals are specified, materials selection should ensure integrity for resistance to the solvent like nature of dense phase CO_2 (e.g. swelling) at high and low temperature and be resistant to rapid decompression.

For the existing Goldeneye pipeline section that is to be retained, there is an additional concern due to the existing pipeline being internally epoxy coated with potential for disbondment in dense phase CO_2. Any deterioration and coating removal would present filtration issues/well blockage risks.

Consideration of the above noted requirements is discussed for the onshore CCCC, pipeline and offshore sections of the proposed Peterhead CCS system in the following sections to confirm the FEED materials design. Also any issues that remain to be detailed further during Execute phase are highlighted.

11.3. Onshore Facilities

The process description for the CO_2 capture plant proposed for Peterhead CCS is detailed in Section 5. The following is a summary of key stages and equipment from flue gas capture through conditioning and compression for materials selection consideration.

11.3.1. Pre-Treatment (U-1000)

Entry specification for flue gas into the CCCC plant from Gas Turbine GT13/HRSG13 outlet at Peterhead Power Station contains approximately 3.8 % CO_2 (mol/v), 12.8 % O_2 (mol/v) and significant water vapour. With flue gas temperature at approximately 110°C at ambient operating pressure, there is potential for condensation through relatively long ducting and equipment with external surfaces exposed to atmospheric conditions as flue gas is driven via the booster fan (K-1001A) and the Gas-Gas Heat Exchanger (E-1001) where it is cooled to 70°C prior to entry into the Direct Contact Cooler (DCC) vessel (C-1001). These conditions present potential risk of internal corrosion including CO_2 corrosion to ducting and equipment upstream of the DCC and corrosion resistant materials have been incorporated in design. Booster fan and the Gas-Gas Heat Exchanger are specified in vendor standard materials (i.e. stainless steel). Flue gas ducting is carbon steel lined with GRVE (Glass Reinforced Vinyl Ester). The DCC column is constructed in internally lined concrete with 304 SS piping/internals. Titanium is required for seawater closed cooling water heat exchanger (plate heat exchanger).

11.3.2. CO_2 Capture Plant - CO_2 Absorber/ CO_2 Stripper (U-2000)

In the DCC, flue gas is cooled to 30°C and saturated by direct contact with re-circulated water prior to entry into the CO_2 Absorber Tower (C-2001), thus ensuring optimum CO_2 absorption and preventing excessive water evaporation from the amine solution. Processing through the absorber tower includes water wash packing trays and acid wash (sulphuric acid) packing trays to meet DMA emission regulations for the treated flue gas which is returned to the gas/gas heat exchanger, and heated to 79°C prior to release into the 170 m tall stack. Corrosion resistant materials for vessels, piping and equipment, or acid resistant linings for the tower structure are required. 316 SS has been selected throughout process fluid pressurised piping. 304 SS grades are considered unsuitable due to potential external chloride stress corrosion cracking risks. The absorber tower is constructed using lined concrete rather than using tiles. Testing has been carried out to qualify the liner system for high temperature amine. Internals for acid wash are 316 SS with wash water piping in 304 SS grade.

CO_2 rich amine is transferred via pre-heaters to the CO_2 Stripper (C-2002) where CO_2 desorption occurs by heating and counter current contacting. CO_2 stripper overhead gas is partially condensed in the Overhead Condensers (E-2005 A/B) and separated through the Reflux Accumulator (V-2001). CO_2 product gas is then transferred directly from the Carbon Capture plant to the compression system via a 40 inch (1016 mm) pipe section. All materials for the CO_2 stripper sections should be specified in corrosion resistant 316 SS. Amine tanks, pumps and filters base case materials are 316 SS although lined carbon steel is acceptable for tanks. The sulphuric acid tank base case is to specify super austenitic stainless steel Alloy 20, however carbon steel options may also be suitable.

The produced gas target composition for design case is 98 % CO_2 (mol/v) with 20 ppmv O_2 and 2 % (mol/v) H_2O. For CO_2 product gas transfer piping to the compression area GRP materials can be considered due to low pressure system design, <2 barg or alternatively 316 SS.

11.3.3. CO_2 Compression and Conditioning (U-3000)

Entry into the CO_2 compression system is through an integrated suction knockout drum (V-3101) at 1.8 barg and 25°C. The multistage compression package (A-3100) comprises a multi-stage compressor with an integrated self-draining/suction knockout drum system. After the fourth compression stage there is also O_2 removal (Puraspec Catalyst) through the oxygen removal reactor (R-3001) to 1 ppmv maximum, and an acid resistant molecular sieve dehydration package (A-3200) to achieve water < 50 ppmw dehydration export specification. All piping and equipment materials for the compression system entry up to dehydration have been selected in corrosion resistant 316 SS, although the risk of water condensation is low. In addition there is a risk of very low temperatures associated with CO_2 depressurisation at export pressure, with lowest design temperature set at -79°C. 316 SS is suitable for brittle fracture resistance. Downstream of final compression stage there is metering and a HIPPS system, before entry into the export pipeline system. As these elements are part of the compression package then 316 SS is also specified for standardization. However, as standard equipment designs may be offered by compressor vendors, carbon steel clad with 316 SS is an acceptable alternative.

11.3.4. CCCC Plant Material Optimisation Opportunities

Technical issues that should be further examined in the Detailed Design phase include the following:

- Booster fan and Gas-Gas Heat Exchanger 304 SS/316 SS optimisation.
- Clad 316 SS compared to solid 316 SS optimisation for compressor packages.
- Concentrated Sulphuric acid tank specification in Alloy 20 compared to Carbon steel.
- 316 SS or GRP for low pressure piping into compression area.

11.4. Pipeline

The main construction materials for use within the subsea scope will be either carbon steel or low temperature carbon steel (e.g., within the SSIV structure). The only exceptions will be the gaskets and specific internal valve components.

The process description for the CO_2 export pipeline proposed for Peterhead CCS is detailed in Section 2.1. The following is a summary of key stages and equipment from flue gas capture through conditioning and compression for materials selection consideration.

Following compression and metering, dehydrated dense phase CO_2 is piped through a new 20-inch export pipeline with an onshore/landfall section approximately 900 m long and routed directly offshore. The new offshore pipeline will require concrete weight coating and ties into the existing 20-inch Goldeneye pipeline offshore, using rigid spools. CO_2 arrival at Goldeneye will be through the existing riser however modifications to the SSIV assembly will be required and the riser tie-in spool will be replaced to ensure consistent design pressure rating for the pipeline system.

The mechanical design for the Peterhead CCS project's new 20-inch export pipeline section will be consistent with the existing Goldeneye pipeline design regards grade and sizing including corrosion allowance and will meet DEP requirements as well as the BS PD8010-2 design code.

The existing 20-inch Goldeneye pipeline to be retained for PCCS service is in serviceable condition and was pigged and cleaned in the Hydrocarbon Freeing Campaign (HFC) completed in May 2013. The pipeline is currently filled with clean water, biocide and oxygen scavenger to preserve the pipeline for up to five years. The existing pipeline is expected to be suitable for the 15 year design life for Peterhead CCS subject to confirmation on completion of Intelligent Pigging (IP).

The CO_2 dehydration specification for export from the capture plant at Peterhead is 20 ppm w/50 ppmv maximum, based on avoidance of water drop out during depressurising and set at approximately 50 % of the calculated minimum saturation level. Therefore the carbon steel corrosion rate is expected to be negligible provided the 99.97 mol % CO_2 dry dense phase gas remains "in specification". Dehydration availability higher than 99 % is assured and this also applies to the new pipeline section. Based on theoretical (i.e. not yet confirmed by Intelligent Pigging) analysis pre-FEED, the remaining corrosion allowance on the existing carbon steel pipeline is considered sufficient for a 15 year PCCS design life. FEED has confirmed that carbon steel is acceptable for the new export pipeline with corrosion allowance specified at 1.5 mm. This includes the onshore section and SSIV piping plus tie-in spools. Should upset conditions result in water entry and dropout in the pipeline, MEG will be injected to remove water and prevent hydrates/corrosion. Sour service resistance is not required as FEED has confirmed CO_2 export gas does not contain H_2S. This should be further evaluated in the Execute phase to ensure any future CO_2 disposal project tie-in options are accounted for.

The existing 20-inch Goldeneye pipeline section is internally coated with thin film epoxy flow coating. Pig trash sampling from the HFC programme contained only a small number of coating flakes and confirmed internal coating appears to be intact. Testing of the coating using samples of spare coated pipe retained from Goldeneye pipeline installation confirmed that the epoxy coating is not disbonded by rapid or uncontrolled CO_2 gas decompression and is suitable for exposure to dense phase CO_2. Longer term testing is considered unnecessary however as testing was carried out using spare pipe and not pipe that has been used in Goldeneye hydrocarbon production. Further testing to fully determine suitability should be considered during the Execute phase (e.g. existing pipe sections removed to enable new pipeline tie-in). These sections could be thoroughly investigated in order to establish existing coating status. 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 the likelihood of debris is minimised for mitigating filtration concerns offshore.

Materials should be suitable for minimum design temperatures and also transient blow down or de-pressuring events and restarts as applicable, causing Joule-Thompson cooling below the minimum design temperature. The nominal minimum design temperature for both new and existing Goldeneye pipeline system sections is 0°C therefore design code compliance would be achieved with -20°C Charpy impact testing and this should be applied as the Minimum Metal Temperature (MMT) as per Shell internal design standard requirements for brittle fracture. This applies to parent metal and welds.

Running ductile fracture propagation control is required for the pipeline design. Detailed simulation of CO_2 gas composition has been completed to model gas decompression and saturation pressure for dense phase operation using the Battelle Two Curve model and establish a range of maximum operating temperatures for the entire length of the Goldeneye pipeline. For the worst case scenario for the existing pipeline with full corrosion allowance removal (3 mm) on the 14.3 mm section close to shore with minimal installation depth overpressure, provided the maximum operating temperature (i.e. entry specification) is <29°C then ductile fracture propagation would be avoided. Therefore 11.3 mm has been adopted for minimum wall thickness on the new pipeline sections, and with required corrosion allowance of 1.5 mm results in 12.8 mm nominal wall thickness for the new CO_2 pipeline section. All other sections of the pipeline are thicker wall (15.9 mm) or in deeper water with increased overpressure. It is noted that the pipeline is not insulated therefore operating temperatures reduce quickly to ambient in the offshore subsea environment. Intelligent pigging data when available, will confirm minimum wall thickness in the existing Goldeneye pipeline section. Data can be used to update operating temperature limits and input to material purchasing specifications for testing.

External corrosion for the new onshore and offshore pipeline sections for Peterhead CCS will be mitigated by a combination of three layer polyethylene (3LPE) corrosion coatings with cathodic protection. Offshore pipeline cathodic protection will be by use of sacrificial anodes. For the onshore section impressed current systems will be installed. It is noted the majority of the 20 inch export pipeline, excluding landfall and spools, is also concrete weight coated, therefore external corrosion coating is likely to be Fusion Bonded Epoxy (FBE) for use with concrete weight coating. Particular attention will be required for the proposed landfall section which will be installed by a horizontal directional drilling.

A complete external pipeline survey assessment, including anode condition, on the existing pipeline section should be carried out to ensure satisfactory coating condition and that the overall sacrificial anode system design proposed for PCCS 15-year design life provides adequate cathodic protection.

11.4.1. Pipeline Material Selection Optimisation Opportunities

Technical issues that should be further examined in the Detailed Design phase include the following:

- Intelligent pigging (IP) of the existing pipeline to confirm corrosion allowance and minimum wall thickness for Ductile Fracture Propagation (DFP);
- Sour service potential for future PCCS use with relation to specification of new materials;
- Cathodic protection and coating survey of existing Goldeneye pipeline.

11.5. Offshore Storage Platform and Wells

Materials selection for the offshore Goldeneye scope is compliant with Shell internal design standards, including the following at Goldeneye platform.

- Pipework on the platform including filters, valves, metering and vents for CO_2 and methanol;
- Pig receiver;
- Injection flow lines (CO_2 and methanol);
- Wellhead injection and Christmas Trees; and
- Well completion.

FEED has determined the applicability of the existing piping class designations for CO_2 service and the need to develop new piping class for CO_2 service. Dense phase CO_2 gas is routed topsides from the existing riser through the existing piping, into an injection manifold for injection into up to four wells for storage in the depleted Goldeneye reservoir. Filters are installed upstream of the injection manifold to remove particles greater than 5 micron before injection into the well. The main design challenges for Peterhead CCS are as follows:

1. Topside piping/well tubing low temperature exposure during depressurisation when process controls fail and temperature could approach the triple point of CO_2 (-56.3°C) or when leakage occurs and temperatures below the triple point are feasible. In addition accidental re-pressurisation of equipment which is already at very low temperatures has been evaluated;
2. Suitability and compatibility of elastomeric or polymeric seals or valve components for CO_2 service in dense phase service and resistance to low temperatures during decompression including rapid gas decompression;
3. Potential corrosion of existing 13 Cr well tubing where free water back flows from wells due to O_2 and also CO_2 corrosion risk where carbon steel casing is exposed to water back flow.

FEED has confirmed that with the exception of the existing Goldeneye Pig Launcher (revised duty as a pig receiver for PCCS) all existing topside carbon steel CO_2 piping for injection and venting is to be replaced by 316 SS, in order to meet low temperature design (-80°C injection to -100°C vent) including piping that is classified as PD 8010 pipeline. For the piping and pipeline elements 316 SS is available in standard schedules/sizes to meet all applicable pressure class ratings. In the case of the pig receiver a low temperature assessment has been completed and a derogation from Shell internal design standards agreed for low temperature brittle fracture application. Using a combination of existing material and weld certified impact energy/toughness data and fracture mechanics methods, the existing materials have been re-rated for actual coincident pressure/FEA derived applied stress/low temperature events during depressurisation and accidental re-pressurisation from low temperatures. Therefore the existing pig receiver will be retained in carbon steel.

The FEED decision to replace all CO_2 piping topsides with 316 SS extends to small bore piping. It is recommended that in Detailed Design the same low temperature assessment rationale (subject to derogation approval) described above is applied to small bore piping and 20 inch pigging valves/piping to determine potential for retention in PCCS CO_2 service, or if replacement by 316 SS or low temperature carbon steel is required.

It is noted that for all topsides CO_2 piping on Goldeneye up to the injection wellheads, internal corrosion risks are the same as for the main export pipeline from CO_2. Gas is fully dehydrated and dew point will be well below minimum operating design temperature 0°C. Therefore carbon steel with nominal 3 mm corrosion allowance would be acceptable purely from consideration of internal corrosion. 316 SS is fully resistant to CO_2 corrosion threats for PCCS design conditions. External corrosion risks will be mitigated by application of suitable corrosion coating for all piping and equipment, and at maximum design temperature (50°C) there is low risk of external stress corrosion cracking (SCC) for 316 SS, with expected normal operating temperatures of <11°C.

Extensive work was carried out during both the pre-FEED and FEED phases to evaluate all topside valves suitability (>40 valves) for CO_2 service. Metallic materials that make up the valves are generally low temperature carbon steel, stainless steel and nickel-molybdenum suitable for low temperatures as defined by their piping class designation and compatible with dense phase CO_2 operation. Due to the costs of refurbishment and additionally to meet low design temperature (-80°C), FEED has confirmed all existing valves shall be removed and replaced, with materials suitable for Peterhead CCS CO_2 service specified in 316 body and trim material, incorporating metal to metal seat designs.

With respect to non-metallic materials, replacement valves shall be fitted with seals resistant to swelling due to liquid CO_2 absorption, embrittlement by reaction leaching of additives and rapid gas decompression. Non-metallic seals shall also be suitable for low temperature service, and be compatible with methanol (MeOH). Rated elastomers include Nitrile Butadiene Rubber (NBR), Hydrogenated Nitrile Butadiene Rubber (HNBR) and Ethylene Propylene Rubber (EPDM) as preferred seal materials for CO_2 service with low temperature rating between -40°C and -65°C. Thermoplastic seals (PTFE and Nylon grades 6/12) are rated to below -100°C and are typically included in the Shell internal design standard piping class for this service (Class 153455).

There remains scarce standard test data available to demonstrate long term seal compatibility with dense phase CO_2. Execute phase should develop testing protocols with vendors to ensure full compatibility compliance of potential non-metallic seals for PCCS service including decompression/low temperature events as part of technology maturation plan.

The Project scope requires two CO_2 filters to be installed, using one at any given time with the second filter providing redundancy, in order to assure well integrity from the risk of potential debris blockage from the export pipeline (5 μm maximum particle size filter specification). There is potential for regular depressurisation of these sections (vessels and piping) with exposure risk to temperatures below minimum design/rated temperature, therefore the base case is to replace materials with 316 SS rated to -100°C. New methanol filters are also specified for PCCS. The FEED decision was taken based on the risk of well contamination and the potential for back flow of wet CO_2 from the wells to specify the methanol filters and piping onto the Christmas trees in 316 SS.

There were no well integrity concerns at the time of hydrocarbon production cessation for Goldeneye. Water wet conditions are assumed at the bottom of wells before commencement of CO_2 injection. During normal operations water will be displaced by CO_2 and therefore bottom hole conditions are expected to be dry, however water may flow back into the well during start up/shutdown. Methanol is injected for these transient conditions to prevent hydrate formation. Well tubing is therefore exposed to the threat of internal corrosion risk from CO_2. Existing well completion materials are specified in 13 Cr martensitic stainless steel (wellhead/tree, tubing, and liner). An excluder screen sits inside the liner and is constructed from 316 SS/304 SS for jacket and shroud with an inner perforated pipe specified in 13 Cr. Carbon steel is specified for casing.

13 Cr is resistant to CO_2 corrosion for these conditions, in particular as low chloride levels are confirmed. However there is residual O_2 in the exported gas and 13 Cr is susceptible to localised corrosion when O_2 is present, as experienced in water injection service. Typically for O_2 the accepted pitting and crevice corrosion limit for 13 Cr is 10 ppbw which is equivalent to 1 ppmv in gas. This limit is noted as a general service limit and there may be potential for relaxation, following accurate determination of O_2 distribution in CO_2/H_2O by experimental work for bottom hole conditions to provide a threshold level for 13 Cr. O_2 removal onshore will meet 1 ppm(v).

Further work to consider the effects of pitting corrosion of the stainless well tubing was done in the Execution Preparation Phase, after FEED was completed. The work has allowed the relaxation of the O_2 content design limit to < 5 ppmv. Please refer to KKD 11.064 - Technology Maturation Plan [6], Section 3.16 for further details. In Detailed Design testing should be considered to establish the 13 Cr pitting resistance at higher O_2 operating limits in order to provide onshore performance operating envelopes.

Carbon steel casing is also at risk of CO_2 corrosion should wet conditions occur. As water exposure is likely to be intermittent during start-up/shutdown from water back flow and normal operations CO_2 export quality is dry, corrosion risk is considered low and therefore casings will be retained. However it is essential that the finalised operating regimes and injection strategy that could result in increased frequency of water wet conditions bottom hole are reviewed to confirm that the materials selection remains valid. It is noted the cement used in Goldeneye wells has been assessed as suitable for CO_2 exposure with minimal degradation risk.

13 Cr tubular grades are generally limited to -10°C minimum service temperature with ductile/brittle transition exhibited at -15°C. The existing Christmas trees are also rated to -18°C. Lower temperatures have been confirmed (-60°C) in FEED for the wellhead and upper completion PCCS CO_2 injection. Therefore replacement down to the subsurface safety valve (SSSV) in Super 13 Cr tubing is proposed which is suitable to -50°C and additional testing will be carried out in the Execute phase to qualify at -60°C. Christmas trees will be replaced in F6NM grades rated to -60°C close to the SSSV, CFD work in FEED has shown that for a leak event SSSV tubing may be exposed to lower temperatures and material rating to -80°C is required. High Nickel alloys (e.g. Alloy 718) are to be evaluated before final decision is made in Execute. Below the SSSV there is no exposure to low temperatures therefore existing 13 Cr is suitable.

Carbon steel casing materials present in Goldeneye wells has been confirmed by material certification to be impact tested at -40°C.

11.5.1. Storage Material Selection Optimisation Opportunities

Technical issues that should be further examined in the Detailed Design phase include the following:

- Investigate low temperature cases for existing small bore piping and 20 inch pigging valves plus associated piping onto the pig trap;
- Valve non-metallic seals CO_2 compatibility;
- 13 Cr O_2 pitting limit corrosion testing;
- Super 13 Cr low temperature Charpy impact testing at -60°C.

11.6. Methanol Supply from St Fergus

Materials selection for methanol supply from St Fergus is compliant with Shell internal design standards. The FEED design proposal is to re-use the existing MEG storage tank (T-7703) and export pumps (P-7704A/B). New piping modifications are required for both low pressure (upstream of the export pumps) and high pressure (downstream of the export pumps) circuits, with tie-in to existing piping designed to legacy piping classes.

The methanol specification is industrial quality, with controlled O_2 and H_2O content. Nitrogen blanketing of the storage tank will ensure minimal uptake of moisture by methanol (hygroscopic) thus there is very low risk of internal corrosion to carbon steel. O_2 levels are expected to be circa 1 ppm in methanol (equilibrated with N_2), consistent with CO_2 export quality from PCCS, therefore additional risk of pitting corrosion to down hole 13 Cr martensitic stainless steel material is also avoided. The specification of carbon steel with 1 mm corrosion allowance for contingency is recommended as a base case for methanol supply piping and equipment modifications at St Fergus. It is noted this is consistent with the 4 inch subsea pipeline to Goldeneye platform materials selection, and also with topside design modifications to the methanol injection system on Goldeneye platform.

The minimum design temperature has been set at -10°C, consistent with the offshore Goldeneye topside modifications. Whilst this is achievable with a new piping class specification, the existing piping legacy specifications confirm materials were rated to 0°C for the original Goldeneye hydrocarbon production duty. All existing piping, flanges and fittings have been evaluated based on available material certification against ASME B31.3 re-rating criteria for brittle fracture resistance, and appear acceptable, with the exception of certain spade/spectacle blinds where there potential replacement is required. A comprehensive checklist should be developed in the Execute phase to document the final review process.

The new piping design includes development of an additional class to ensure piping sizes are acceptable for material grades required with satisfactory impact toughness design rating to meet -10°C.

The existing valves and pumps used for MEG service but now intended for methanol duty, have been checked to ensure the materials are suitable for re-use. Metallic materials comprise carbon steel or CRA grades that are confirmed as acceptable for methanol service for available material certification. The non-metallic seals for existing piping classes have been reviewed and accepted for methanol use except that Viton AED grade elastomer requires further checks. It is noted the export pumps are due for overhaul and therefore will have seals changed out. Static seals in Nitrile (Buna-N) material are suitable for methanol filters.

12. General/Common Facilities and Systems Descriptions

12.1. Civil/Structural/Architectural

12.1.1. Site Preparation

The Peterhead Power Station was constructed to be partially screened from public view by building the plant in excavations adjacent to the seashore. This resulted in a highly undulating site with large differences in site levels. To achieve the conceptual CCS layout it will be necessary to carry out extensive earthworks and rock removal.

The Carbon Capture Plant equipment location is planned to be at the main power station grade level. Currently this area at least partially comprises an approximately 18 m high earth embankment. This embankment will have to be excavated back a significant distance over a length of about 250 m. This embankment reduction will result in extensive excavation quantities. It is also known from previous soil investigations that this embankment contains a significant amount of overburden and weathered granite layers. On some instances, solid granite blocks were encountered which will necessitate bulk rock extraction.

After the embankment excavation, the new slope will need to be stabilised. Various slope stabilisation techniques have been investigated during the FEED phase. It was concluded that soil nailing is the most effective technique. This will allow for a steep slope up to 70° which will increase the plot space for the new capture plant.

The CO_2 Compression and Conditioning Facilities are proposed to be on a previous fuel oil storage tank location. These redundant tanks have been removed and the general area has been decommissioned. The existing plot has been remediated and left as bare soil in three terraces each dropping approximately 3.1 m at the two terrace transitions.

It will be necessary to fill the whole area up to the level of the higher area with suitable granular fill material in order to provide a common grade for the Compression/Conditioning Facilities. This location is also partially surrounded by earth embankments varying up to 13 m high which may require partial removal/opening up to improve air circulation in this area. This will require extensive backfilling quantities. The excavated materials from the embankment in the CCP area will be used for filling the area with the final level adjusted to accommodate the excavation quantities.

Other site preparation works will involve widening and re-grading the existing site roads for the new facilities. It will probably be necessary to do this work in advance of major equipment arriving on site in order to facilitate equipment transportation given the existing topography of the site.

Based on the existing soil investigation reports for the site all foundations will be of shallow ground bearing type either founded directly on the bedrock or on the overlying soils. No piling is anticipated for foundations.

Some of the new equipment and structures will be located in areas currently occupied by existing equipment, steel structures, transformers, drainage sumps, cable ducts, pipe trenches, etc.

While much of this equipment and its associated foundations and underground services can be removed there will be some services such as electrical cables or the fire main that will have to be retained or rerouted. It is recommended that the locations of existing services that have to be retained are identified so that they can be incorporated into the design of the new works.

Disinvestment/demolition drawings should be prepared in advance of the Detailed Design for the new PCCS project works.

12.1.2. Buildings

There are a number of new buildings required for the CCS plant to allow the facilities to be independent of the power plant. The main buildings are:

- Main Substation Building ESS-3000 – to receive incoming power from the national grid;
- Distribution Substation ESS-2000 – to provide distribution of power to the capture plant;
- Compressor Building – a steel portal framed structure with roof sheeting and full wall cladding giving rain protection to the compressor and associated equipment and also to help reduce the noise levels generated by compressor;
- PCCS Control Room Building – for the overall CCS facility;
- Laboratory – Is currently included in the control room building; and
- Workshop and Store (Mechanical, Electrical & Instrumentation).

The PCCS control room building is a blast proof steel structure with an elevated floor to accommodate the bend radii and distribution of incoming cables. The PCCS control room building will also accommodate the following facilities:

- Operations and Maintenance (desks for two persons);
- Vendor Support (desk for one person);
- Technical Library and Store Rooms;
- Logistics/Ops Support (two persons);
- Training Room (approx. 10 persons);
- First Aid Room;
- Kitchen/Dining Room;
- Changing/Locker Room; and
- Toilets.

The workshop and store building shall be suitably sized to accommodate the following:

- Storage (typically 30 Racks, 2 m x 1 m x 5 m);
- Clean Storage Room (typically 20 racks 1 m x 1 m x 4 m); and
- Discipline Workshops (electrical, instrumentation and mechanical).

It has been agreed to share the existing SSE Security Gate House building for access control to the overall Peterhead Site. All buildings will be of an appearance similar to existing buildings on the site, matching in colour, form and construction where possible.

12.1.3. Roads

Site roads and access ways will be of flexible, asphalt construction, including sub base, road base, wearing course and including all road markings and signage. Roads shall be designed to accommodate construction traffic in the short term and give adequate access to the facilities for operation and maintenance activities over the life of the facilities. The roads shall be constructed in accordance with SSE specifications as a minimum, exceeding these requirements where necessary for specific plant design conditions.

12.1.4. Modifications to Road Junctions off the A90

12.1.4.1. Main Site Access

It is proposed that the existing site access will be upgraded to include a ghost island junction arrangement as shown in Peterhead CCS A90 Main Site Access Proposed New Layout - General Arrangement Plan [65]. The existing road markings will be removed and new markings laid as indicated in the general arrangement plan. The splitter island will be remodelled to incorporate a traffic refuge which pedestrians or cyclists can utilise, it will also house a new lighting column, two reflective bollards and a directional/entry sign for the power station.

As part of the access improvement it is proposed that the existing 40 mph speed limit will be extended (north) to incorporate the access. This will require a formal Traffic Regulation Order to be promoted by Transport Scotland. Physical works will also be required including the relocation of existing speed limit signs (currently situated approximately 200 m to the south of the access) to be repositioned approximately 120 m to the north of the access.

12.1.4.2. Sandford Access

The existing access is proposed to be increased in size to include 15 m radius curves (with 1:10 tapers over a distance of 25 m) as shown in the general arrangement plan [66]. The enhanced access will require to be constructed with full depth carriageway construction. A stone-filled drainage ditch will be constructed to the north side of the adjoining track and the surfacing at the access will be graded to ensure surface water run-off falls towards the new ditch. The existing footway/cycleway will be realigned with the redundant section broken out and re-profiled. New road markings will be laid and signs installed as indicated in the general arrangement plan with the existing bollards relocated relative to new construction.

12.1.5. Fencing

The CCCC plant area and the power plant will be segregated by a security fence. The extent of new fencing which will be required for PCCS has still to be confirmed.

The specification for new security fencing will be developed during the Execute Phase and will be subject to approval by both Shell and SSE.

12.1.6. Structural Steelwork

Steel structures will be utilised extensively throughout the facility including pipe racks, process structures, duct supports, structural pipe supports and platforms including handrail, ladders and cages, flooring, stairs etc. Primary and secondary pipe racks will be steel construction and will not be fireproofed. Some modifications and additional steelwork will be required to existing pipe racks to support the flue gas ducting. Buildings will also utilise structural steelwork.

All steelwork shall be designed and detailed to current relevant Eurocodes (UK national annexes).

12.1.7. Demolition

In order to accommodate the CCCC plant and the required power plant modifications it is necessary to demolish some of the existing power plant equipment. The demolition work will be carried out by specialist demolition contractors after a comprehensive survey of the existing site facilities in the affected areas has been carried out. The following structures and facilities shall be demolished:

12.1.7.1. Unit 2 Steam Turbine and Associated Equipment

The existing Unit 2 660 MW steam turbine is to be replaced with a 130 MW steam turbine. However the LP casings and condensers of the existing steam turbine will be reused. The exact scope of demolition will be confirmed once proposals have been received from steam turbine vendors. The anticipated scope of demolition activities associated with the steam turbine is described below:

1. HP and IP steam turbine cylinders;
2. LP steam turbine cylinders may be required to be demolished dependent on the final vendor selected;
3. HP steam chests and loop pipes;
4. IP steam chests and loop pipes;
5. LP steam crossover pipes;
6. Gland steam system including pipework, associated with HP and IP cylinders and valves chests, and gland steam condenser;
7. Drain system pipework and valves, associated with HP and IP cylinders, including drains vessel;
8. Lube oil supply and return lines, associated with HP, IP and LP cylinders, generator and exciter but excluding lube oil tank and associated equipment;
9. Lube oil tank and associated equipment as an optional priced item. This option is required to reflect the proposed scope from different steam turbine vendors;
10. Jacking oil system;
11. Hydrant monitoring unit and associated pipework to valve actuators;
12. Condensate extraction pumps;
13. Generator and exciter;
14. Generator hydrogen cooling system;
15. Generator stator cooling system, including pipework, distilled water pumps, stator liquid cooler, distilled water cooler and liquid stator unit;
16. Generator seal oil system including pipework, coolers, dirty oil tank and pump and disposal of seal oil;
17. Isolated phase bus ducts from generator to transformers;
18. Unit transformers and associated cooler, including disposal of transformer oil;
19. Generator transformer and associated cooler, including disposal of transformer oil;
20. Low voltage switchboards and dry type transformers located in electrical switchgear rooms; and
21. Removal of redundant cables within the turbine hall.

12.1.7.2. Auxiliary Boiler House and Associated Equipment and Structures

The scope of demolition activities associated with the Auxiliary Boiler House is described below:

1. Aux boilers (4 off) and associated pipework within the Auxiliary Boiler House;
2. Deaerator, extraction pumps, blowdown vessel, flash vessel and feedwater tanks associated with the auxiliary boilers;
3. Associated switchgear, instrumentation panels and cabling;
4. Auxiliary Boiler House and associated above ground structures;
5. Auxiliary Boiler House transformers and associated above ground structures;
6. Auxiliary Boiler day tanks and associated above ground structures;
7. Auxiliary boiler flue duct and associated above ground structures, from Auxiliary Boiler House to chimney; and
8. Associated above ground services including piping and cabling.

12.1.7.3. Propane Store

The scope of demolition activities associated with the propane store is described below:

1. Propane storage tanks, valve house and associated above ground structures;
2. Associated propane pipework and support structures; and
3. Associated above ground services including piping and cabling.

12.1.7.4. Gas Mixing Manifold

The current scope of demolition activities associated is described below:

1. Gas and steam pipework and associated above ground structures.

12.1.7.5. Pipework within Boiler House and Turbine Hall

The scope of demolition activities is described below:

1. Assorted steam, condensate and water pipework and associated structures.

12.1.7.6. Unit 1 & 2 Flue Gas Ducts, ID Fans and Associated Structures

The scope of demolition activities associated is described below:

1. ID fans;
2. Grit arrestor;
3. Associated above ground structures;
4. Flue gas duct and associated above ground structures from Air Heater Annexe to chimney;
5. Associated above ground services including pipework and cables.

12.1.7.7. Garages and Storage Area to the West of the Chimney

The scope of demolition activities associated is described below:

1. Garages;
2. Storage area; and
3. Associated above ground structures and services, i.e. piping, cabling and associated structures.

12.1.7.8. Feed Heaters

To facilitate the demolition of the existing Unit 2 steam turbine and subsequent installation of the new steam turbine it is necessary to demolish the feed heating equipment associated with the steam turbine. The scope of demolition activities associated with the feed heaters is described below:

1. Feedwater regulating valves and associated pipework and structures;
2. HP heaters and associated pipework, valves and associated above ground structures;
3. LP heaters and associated pipework, valves and associated above ground structures; and
4. Associated above ground services including pipework and cables.

12.1.7.9. Gas Pressure Reducing Station Pipework

The scope of demolition activities associated is described below:

1. Gas heaters, valves, pipework and associated above ground structures.

12.1.7.10. Heavy Fuel Oil (HFO) Tank Bases and Fire Break Tank (Tank Farm)

The scope of demolition activities is described below:

1. Fire break tank (tank farm);
2. Base for HFO Tank 1; and
3. Associated underground services including piping, cables and ducts.

12.2. Instrumentation and Control

12.2.1. General

The general control system architecture for the Peterhead CCS project will be an Integrated Control and Safeguarding System (ICSS). This will be confirmed during the Execute phase of the project. The onshore ICSS shall be located within a new control building at Peterhead power station CCS site. The ICSS shall provide overall control, shutdown and fire and gas protection for the following onshore project facilities:

- Carbon Capture Plant (Interfacing with field mounted PLC based systems);
- Compression and Conditioning Package (Interfacing with vendor UCPs); and
- All associated piping and ducting.

The main onshore ICSS for the project shall interface with the existing Honeywell ICSS on the normally unmanned Goldeneye platform for the provision of control, shutdown and fire and gas protection. Data communication between the new project ICSS and existing Goldeneye systems shall be performed via dual redundant communication links.

The main onshore ICSS will interface with the SSE's Peterhead Power Station control and safeguarding systems, to provide alarm and trip functions for the project Gas Turbine Generator (GT13) and the project Steam Turbine (ST20) located within the power station boundary. Control functionality of both turbines shall be confirmed during the Execute phase of the project.

The Onshore ICSS will also interface with St Fergus (Onshore) which will supply methanol to the Goldeneye installation.

12.2.2. Automation, Control and Optimisation (Process Control)

12.2.2.1. Introduction

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 shortage.

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 slowly relax 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 acts 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 pipeline tubing bundle.

12.2.2.2. Overall Capacity Control

The maximum delivery of CO_2 from the carbon capture plant is 138 t/h. The GT13 unit is assumed operated at full throughput initially. Later in the project the GT13 can also be run at reduced throughput, down to approximately 86 t/h, as determined by storage reservoir conditions. If the GT13 is stopped, CO_2 capture stops as well. Line-pack is used to maintain offshore injection during the outage for as long as possible.

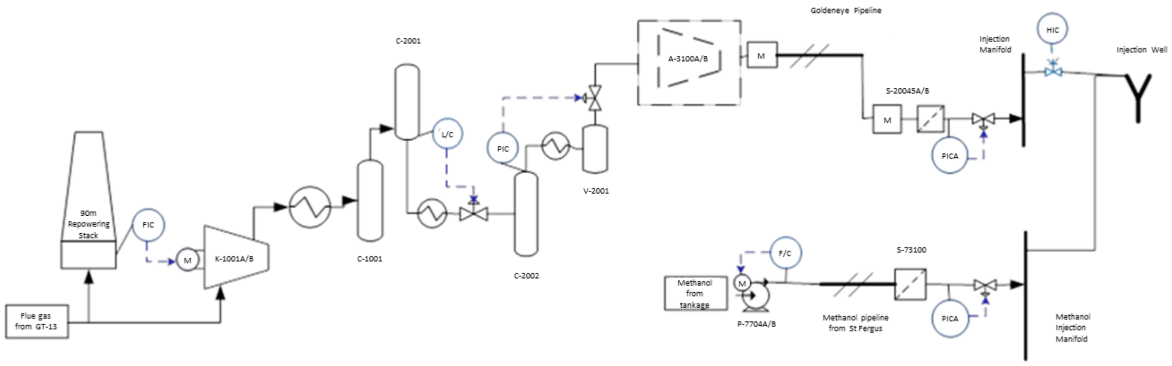

Figure 12-1: End-to-end throughput control

The GT13 flue gas flow rate is set by the operation of the power station. Since a small fixed flow of flue gas to the 90 m repowering stack is controlled, the flow through the Gas Pre-Treatment unit will automatically be adjusted.

The rich amine flow will be set by liquid level control at C-2001. Pressure control at C-2002 will set the forward gas flow to the Compression and Conditioning plant. Export gas to the Goldeneye pipeline will therefore be ultimately set by the inlet flue gas rate.

To maintain the required linepack, 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 %. Ultimately, when more than one injection well is operated, the individual chokes at the wellhead will allow for fine tuning of the relative injection rates.

The flow of methanol from onshore to offshore is also set by push from onshore flow control. The common methanol injection pressure to the wells is therefore also controlled. This represents a push production strategy.

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 widen-up 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.

When the pipeline pressure is reduced due to pipeline de-packing, the pressures in the main compressor and in the oxygen and water removal reactors at mid-stage are maintained with the use of a backpressure control valve at the compressor discharge.

12.2.2.3. Process dynamics

The varying pressure in the pipeline enables the exploitation of line-pack to avoid immediate shutdown upon loss of CO_2 transfer to the offshore pipeline system. This is desirable as frequent starting and stopping of injection wells is to be avoided because this can cause early well failure.

When the pipeline is held at maximum injection pressure, the lead time for reduction to minimum injection pressure would be some 2 hours. This has been further extended to approximately 3 hours because injection is immediately reduced to minimum quantity upon loss of supply, i.e. when the supply from the Peterhead flow meter is reduced to a value below minimum injectivity of the current well.

The reduction of injection can enable more time for restoration of the design quantity. In the longer term, if the CO_2 to be injected stays below minimum design value, a well with a lower injection rate should be selected, and the original injection well should be stopped.

12.2.2.4. Level of Automation

The whole process will be monitored and controlled from a dedicated PCCS control room. All normal operations will be automated, i.e. the operator will not need to intervene in case of normal operations. Starting or stopping will be done by the operator from the control room with at least one field operator in attendance for starting major rotating equipment such as the booster fan and the main CO_2 compressor.

Operations at the Goldeneye platform will be controlled remotely from the central control room under normal circumstances. This includes also the starting and stopping of wellhead operations, including provision of methanol prior to and following the start of a well.

When there is a mismatch between CO_2 supply and well injectivity, the control system will in the short term make use of available line pack. In the long term, the operator may need to intervene.

Line-pack will be used by the operator as much as possible under the circumstances. Whether there will be enough line-pack available for bridging the gap between under- or oversupply of CO_2 will depend on the prior circumstances.

12.2.2.5. Brownfield/integration of new systems

The system of carbon capture, compression, pipeline and injection will be operated as a new, independent entity, alongside the Peterhead power station.

12.2.3. SSE Control and Safeguarding Systems (Peterhead Power Station)

As part of this project, there shall be a requirement for the Carbon Capture Storage project ICSS to interface with the existing Peterhead power station control and safeguarding systems. The current control system being utilised at the power station is a Siemens Teleperm XP (now re-labelled as SPPA-T2000 by Siemens). This is a process control system based on Siemens AS620 automation system and the OM650 Human Machine Interface (HMI).

The AS620 automation system consists of three sub-systems:

- AS620-B - this is used for "standard" automation, and is based on S5 PLCs;

- AS620-F - this is used for “failsafe” protection applications (the safety/trip systems), and is based on S5-95F failsafe processors; and
- AS620-T - this is the turbine control system, based on high speed Simadyn CPUs.

The general layout of the power station automation system is based on instrument cables being routed from the field locations to cabinets within a “Process Control Centre” (PCC). There are separate PCCs for the GT and the HRSG.

There may also be some remote I/O stations in smaller cabinets out in the field, with a digital bus used to connect the I/O to the main controllers. The main controllers are linked to a fibre optic bus, using “normal” TCP/IP networking. The HMI components also link to this bus.

The OM650 HMI consists of a number of Unix servers and desktop PC operator terminals.

To allow the CCS control system to be interfaced with the power plant the control system for GT13, HRSG13, ST13 and associated common services shall be upgraded to the new Siemens system SPPA T3000.

12.2.3.1. Project Turbine Generator (GT13)

It is envisaged that transfer of a number of interface signals (i.e. Alarm, Indication and Trip) between the main Peterhead CCS project control system and the Power Station control system will be required for control of the project gas turbine generator. The GT13 control system shall be upgraded to the Siemens SPPA T3000 control system. This new PPS dedicated system shall interface with the CCS system to report alarms and status information. The exchange of specific 'inter-system' information shall be determined during the detail Detailed Design. The two new systems (CCS and PPS) shall be interlinked with a dual redundant diverse routed Ethernet communications for bi-directional alarm and status information exchange. The two systems shall be time synchronised to allow resolution of sequence of events reports at either CCS or PPS site.

The interface trips between the CSS and PPS plants have been incorporated in the PSS Cause and Effects Diagrams [67] and CCS Cause and Effects Diagrams [42]. The interface signals for indications, alarms, graphic displays between the Peterhead CCS control room and Power Station Control room have been reviewed in the Human Factor Engineering meeting during the FEED phase. The interface signals shall be reviewed and confirmed during detailed engineering phase.

12.2.3.2. Steam Turbine (ST20)

It is envisaged that transfer of a number of interface signals (i.e. Alarm, Indication and Trip) between the main Peterhead CCS project control system and the Power Station control system will be required for control of the project steam turbine.

The steam turbine shall be controlled by a new Siemens SPPA T3000 control system. The two new systems (CCS and PPS) shall be interlinked with a dual redundant diverse routed Ethernet communications for bi-directional alarm and status information exchange. The two systems shall be time synchronised to allow resolution of sequence of events reports at either CCS or PPS site.

This new PPS dedicated system shall interface with the CCS system to report alarms and status information. The exchange of specific 'inter-system' information shall be determined during the detail engineering phase.

The interface trips between the CSS and PPS plants have been incorporated in the PSS Cause and Effects Diagrams [67] and CCS Cause and Effects Diagrams [42]. The interface signals for indications, alarms, graphic displays between the Peterhead CCS control room and Power Station Control room have been reviewed in the Human Factor Engineering meeting during the

FEED phase. The interface signals shall be reviewed and confirmed during detailed engineering phase.

12.2.4. CCS Instrumentation Control and Safeguarding Systems (Onshore- CCCC)

12.2.4.1. Process Control System (PCS)

The PCS shall form the core of monitoring and control, to which all other (sub) systems shall communicate. The PCS provides the operator interface to all control/monitoring and protection systems, i.e. the PCS HMI enables a "single window" to access the PCS, Instrumented Protective System (IPS) and the Fire and Gas System (FGS).

Data transmission for "information only" and for actions which are neither time critical nor safety related shall preferably be routed via redundant communication links. Hardwired links or dedicated secure busses shall be used for time critical and safety related data.

All PCS systems in the project shall be able to communicate with each other without compromising operation (i.e. CCCC and Goldeneye facilities). It is recommended that the PCS/IPS and FGS shall be supplied by one vendor.

12.2.4.2. Instrumented Protective System and Fire and Gas System

The IPS and FGS shall provide the required level of safety completely independent from the PCS and from each other and shall use dedicated initiating and actuating devices, except for cases where the FGS and IPS share the final element. Systems cycle time shall not exceed 500 milliseconds at facilities start up.

Some system inter dependency is accepted for specific applications, such as two-out-of-three (2oo3) voting with Middle of Three selection, Measurement Validation and Comparison, overrides, PCS actions initiated by Instrumented Protective Function (IPF) interlocks.

IPS/FGS shall be programmable using Functional Logic Diagrams. All IPS and FGS systems in the project shall be able to communicate with each other without compromising operation (i.e. CCCC and Goldeneye facilities).

12.2.4.3. Time Synchronisation

Systems in the Process Control and Office domains shall have time synchronisation capability using a master clock system. The master clock shall be an external, Global Positioning System (GPS) based clock with accurate time keeping covering for long time GPS signal loss, GPS time signal errors and power failure.

12.2.4.4. Sequence of Event Recording (SER)

For post-mortem analysis, a Sequence of Event system shall be provided to capture all process, safeguarding and fire and gas detection alarms and events, e.g. operator actions, equipment status, etc. into a single database. All SER related information from Peterhead Power Station, CCS, Goldeneye and St Fergus shall be time stamped and displayed in the PCS. The detail engineering contractor shall provide a master time signal within the CCS project to align and synchronise control and safety system time with SSE, Goldeneye and St Fergus to ensure sequence of events analysis

Alarms and events shall be logged in a single database with a maximum resolution of 1 millisecond for alarms/events generated by the PCS. The IPS alarm/event resolution shall be equal or better than the IPS scan time.

12.2.4.5. St Fergus Instrumentation Control and Safeguarding System.

The existing Honeywell (ICSS) Integrated Control and Safeguarding System that operates Goldeneye is to be retained and reused with suitable modifications made to accommodate the change from glycol fluid to methanol fluid supply to Goldeneye.

The graphics and trips at St Fergus will be modified to reflect the changeover from glycol to methanol.

The new graphics at Peterhead CCS ICSS will accommodate the methanol system.

The modifications consist of:

- Modified existing graphics to be handed off from St Fergus to Peterhead for methanol;
- New Graphics for ESD Valves at St Fergus to be handed off to Peterhead;
- Signals from Goldeneye to be displayed at St Fergus and Peterhead;
- "Trip Methanol Pumps" Signal from Goldeneye via Peterhead to St Fergus.

A new Process Control Narrative has been prepared to reflect the change from glycol to methanol fluid.

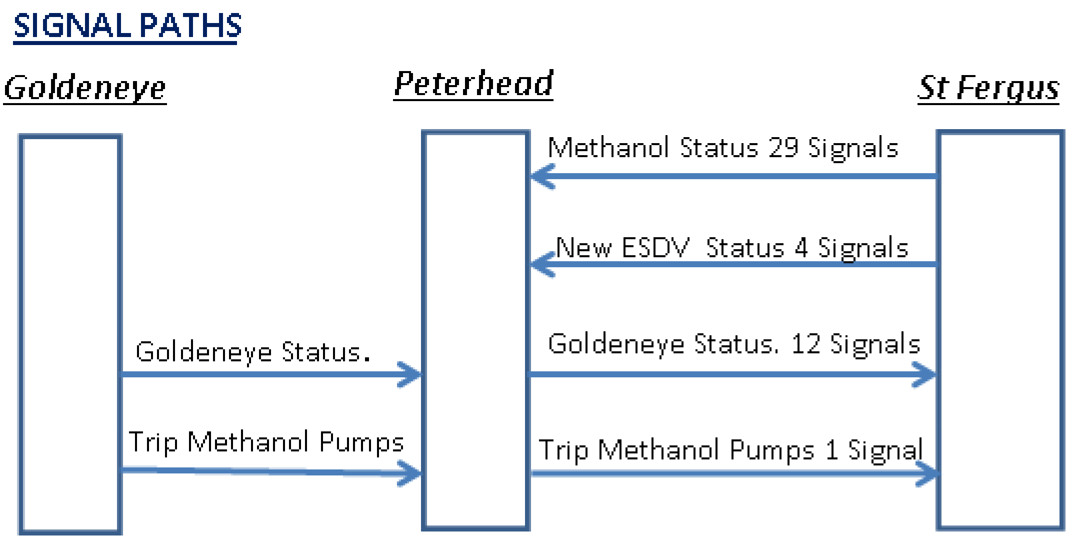

Figure 12-2: Signal Paths

12.2.5. Goldeneye Platform Instrumentation Control and Safeguarding System (Offshore)

The existing control facilities on the Goldeneye platform are contained within a Honeywell Integrated Control and Safeguarding System (ICSS). This system contains the Process Control System (PCS), Emergency Shutdown (ESD) and Fire and Gas (F&G) safety instrumented functions.

At present, control on the Goldeneye platform is handled by the offshore ICSS under the supervisory control of the onshore St Fergus Terminal ICSS Human Machine Interface (HMI). This allows the Goldeneye platform to be remotely operated but still require local intervention for platform restarts (i.e. after process trips) and well start-ups.

As part of the Peterhead CCS project, a fully automated control strategy of the offshore facilities shall be adopted to minimise offshore visits. The control of the platform ICSS shall be transferred to a new Peterhead CCS control room located at Peterhead Power Station. However the platform ICSS system shall still maintain an operator console to allow the transfer of responsibility for process control and safeguarding from the new Peterhead CCS control room at Peterhead Power Station to the offshore facility when the platform is manned.

Existing Goldeneye ICSS graphics shall be maintained and modified as required. All offshore graphics shall be displayed in the new Peterhead CCS control room at Peterhead Power Station.

To accommodate the requirement for fully automated control of the offshore facilities on the Goldeneye platform (including remote operation of the wells), appropriate field and system technology shall be used (i.e. Smart for well surveillance).

12.2.6. Process Control Domain (PCD)

PCD security requirements shall be embedded in the system architecture of the automation systems which will communicate between the various locations. The architecture for Goldeneye and St Fergus with respect to Peterhead Power Station and the Carbon Capture Plant will have some differences. The differences are with respect to Shell DEPs and Industry Standards (Onshore) adopted.

12.2.6.1. PCD Network Levels

The integrated control and safeguarding systems of the facility comprises following levels:

- Network Level 1 – Field bus: Connects field devices to the control and monitoring devices. Direct connection of point Instrumentation is also made at L1;
- Network Level 2 – Control bus: Connects the system controllers, the PCS HMIs and sub system/third party systems via gateways. Furthermore some sub systems, such as flow measurement systems will have their own, dedicated proprietary Level 2 network;
- Network Level 3 – Process Control Network (PCN): This site interaction backbone connects to the level 2 networks, Plant Information system, application servers (e.g. supervisory computers for metering flow measurement), system servers and to the Level 4 office domain network;
- Network Level 4 – Office Domain Network: This GI network is intended for business and general purpose applications;
- Network Level 5 – Internet.

As depicted in the figure below, Level 1 to 3 will form the “Process Control Domain”. The characteristic of this domain is the “real time” requirement for control and safeguarding application whilst the “office” domain of Level 4 and 5 do not have this requirement. Firewalls shall be installed between each of the levels from L2 through L5.

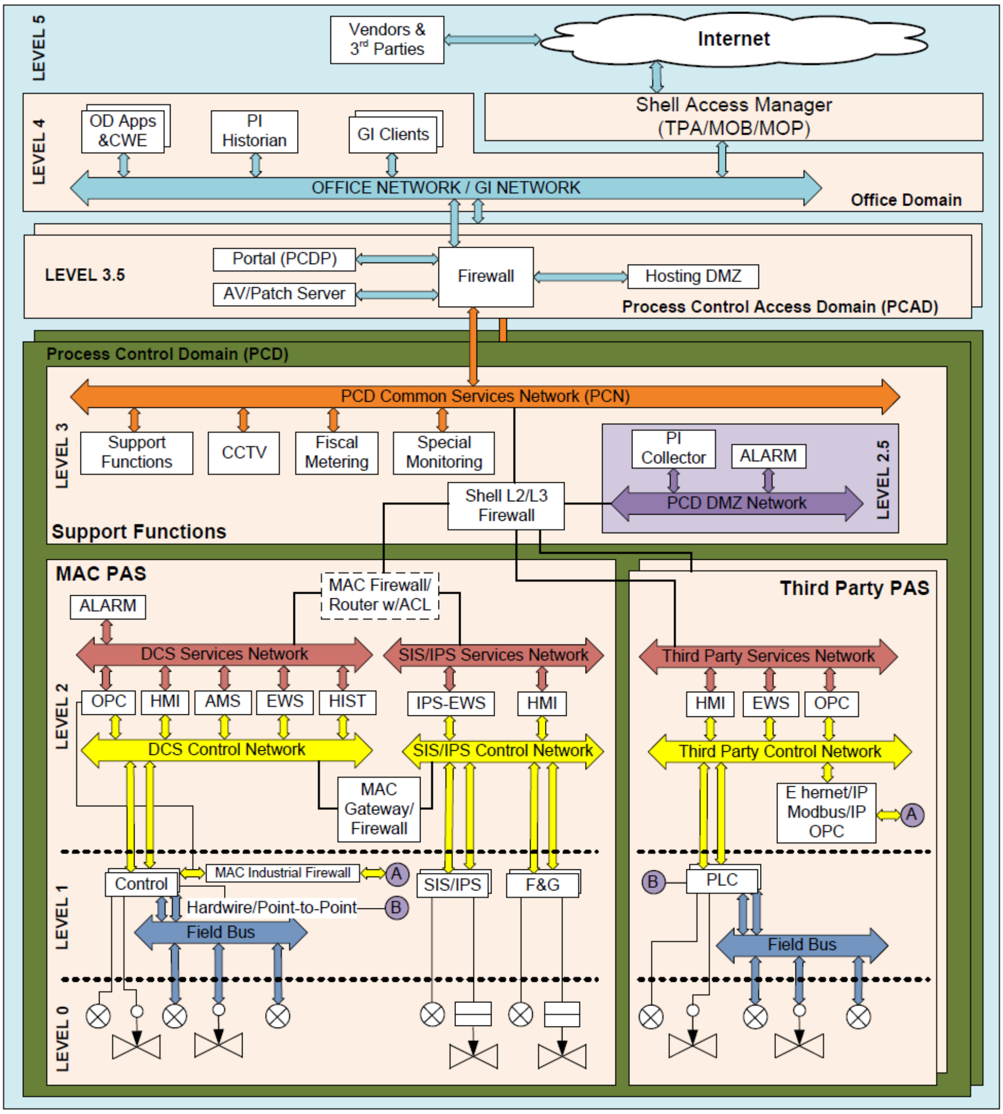

Figure 12-3: Shell PCD Technical Reference Model

The automation architecture shall allow a phased implementation of base layer and upper layers without overloading the process control network infrastructure.

12.2.6.2. PCD Security

To ensure the security requirements, the system Offshore (Goldeneye / St Fergus) architecture shall include a Process Control Access Domain (PCAD) embedded between Level 3 and 4, i.e. between Process Control and Office Domain. The CCCC plant architecture will have Firewalls installed at suitable engineering levels within the architecture.

12.2.6.3. PCD Functionality

PCD functionality shall include aspects such as back-up and restore, disaster recovery, network management incl. intrusion detection or abnormally detection, system management incl. asset registration, domain control (active directory, user access), remote access (single or concurrent), Microsoft patching, application/vendor patching, antivirus updates (preference is Symantec), white listing, function/application availability, printers, time synchronisation, vendor specific domain or community design, file or data transfer. PCD Security Tools shall be installed, such as WhatsUp Gold and optionally Intrusion Detection Systems.

12.2.6.4. PCD Sizing

The data transfer requirements at every network level shall be analysed in sufficient detail to guarantee that all networks are properly sized during normal and fault scenarios. Simultaneous loss of the one leg of each redundant network level shall not result in functional degradation of HMI, operability, maintainability, data collection, remote access, etc. The PCD sizing shall be part of the overall Process Automation, Control and Optimisation (PACO) system sizing.

12.2.7. Instrumentation of Sub Systems and Third Party Systems

The Peterhead CCS project requires segregation of GT13 and HRSG13 from “Block 1”. The new arrangement of GT13/HRSG13 shall provide the flue gas to the carbon capture plant and steam to the new steam turbine generator. The preferred control system separation will be to upgrade the obsolete existing control system of the GT13/HRSG13 to Siemens T3000 system. Common utilities such as feed water and steam systems, including de-aerator and by-pass etc., which are used for the other GT/HRSGs and steam turbine will be incorporated into the new upgraded control system.

The new control system for the carbon capture, conditioning and compression plant shall be installed in the new Peterhead CCS control room. The new control system shall interface to the upgraded T3000 control system for GT13, HRSG13, ST20 and common services via redundant serial link. ESD signals will be hard wired from the carbon capture, conditioning and compression ESD system to the GT13/HRSG13 ESD system.

The new PCS will provide a high level of information and functionality to the operators. The PCS shall be seamlessly interfaced with control systems and sub-control systems, as required to meet the project objectives and shall communicate with other control system and sub-control systems using redundant, high speed, secure interfaces. The communication with the existing Honeywell system at Goldeneye shall be via a redundant broad band link, refer to Control System Architecture drawing [68].

Parts of the overall plant will be controlled as a package, with suitable interfaces to the ICSS, package control systems are required for, but not limited to:

- Ion Exchange Package;
- Electrical Control System;
- CO_2 Compressor;
- Waste Water Treatment;
- Metering package.

The CCS Process Control System (PCS) will interface with the following applications:

- Master Clock System;
- Alarm / Event Management System;
- Asset Management System.

The PCS will also have interfaces to the following:

- SSE Power Station Control System;
- Goldeneye Control System;
- Ion Exchange Package;
- Electrical Control System;

- Compressor Control System;
- Machinery Monitoring System;
- Metering System;
- On-Line Analyser Systems;
- St Fergus Terminal.

12.2.7.1. Pipeline Leak Detection System

The pipeline leak detection system shall be located onshore in the Peterhead CCS control room. Offshore flow, pressure and temperature measurements shall be provided for this system.

12.2.7.2. Compressor Controls

For compressor control, the manufacturer's standard microprocessor based control/ safeguarding system may be used.

It shall include monitoring functions and control/logic functions for manual or automatic sequential start up to design speed without process load. The operator HMI for all relevant operating parameters and alarms shall reside in the PCS.

12.2.7.3. Anti-surge Control

The anti-surge control system shall be provided by the compressor vendor and its design shall be verified by dynamic simulation. The design may require an independent IPF that trips the compressor and opens the recycle valve on detection of a surge parameter (calculated by the IPS).

12.2.7.4. Process Conditioning Package

Control of the Process CO_2 Conditioning Package may be performed by vendor provided PLCs located within the field (the preferred FEED design solution), which shall interface with the project ICSS for the provision of alarm and trip functions.

12.2.7.5. MCC

Control and trip functions for all motors provided for this project shall be routed through a new Motor Control Centre (MCC).

12.2.7.6. Sub-sea pipeline over pressure protection

An ESD system shall be installed onshore at Peterhead power station as part of the CCS project to protect the existing subsea Goldeneye pipeline from over pressurisation. This sub-sea pipeline SIF shall integrate with the project ICSS, for the provision of alarms/trip functions.

12.2.7.7. Instrument Asset Management System (IAMS)

The Instrument Asset Management System (IAMS) shall be embedded in the ICCS and shall provide the following:

- Implement a facilities wide IAMS system to enable efficient handling of diagnostic data of smart analogue instruments, with the intention to direct maintenance activities. IAMS covers all smart analogue (i.e. process parameter value) signals, except complex QMIs;
- The IAMS system must support both Electronic Device Description Language (EDDL) and FDT/DTM (Field Device Tool/Device Type Manager) software to effectively diagnose and commission Smart Field Instrumentation;

- IAMS will enable instrument diagnostic alarming/efficient loop testing and record maintenance activities (calibration, re configuration, etc.);
- The IAMS platform shall be an integral part of the PCS and should not require additional input/output modules, with the exception of Hart multiplexers if the IPS system I/O cards don't support Hart pass through functionality;
- IAMS shall serve signals from Foundation Fieldbus devices, Profibus devices (if applicable) and Smart/HART field instruments under a single platform.

12.2.8. Field Instrumentation

12.2.8.1.1. Diversity of Control

The variety of instrument makes, models and software revisions used on the site shall be limited as far as practicable to improve design efficiency (e.g. configuration), create flexibility during the Execute phase and optimise stock keeping and interchangeability during the Operate phase of the facilities. This is achieved by:

- Standardising on instrument types, versions and accessories (e.g. one type of positioner of all types of control valves);
- Creation and freezing of a project vendor list for tested and proven PACO hardware and software, i.e. a project specific shortlist of makes and models to be applied on the project, extracted from Shell's global TAMAP (Technically Acceptable Manufacturers and Products) list. The list shall include Enterprise Framework Agreement (EFA) supplied and non EFA supplied items and the version number of FF and HART devices.

The project vendor list will be created during Detailed Design, directly after selection of the EFA vendors, and should aim to cover 98 % of all installed field instruments and valves/valve components, including those on 3rd party systems/package units.

12.2.8.2. Smart Instrumentation

Intelligent (smart) devices will be applied to improve measurement accuracy and to reduce installation, commissioning and maintenance costs. The level of smartness and the settings of operational and diagnostic parameters for each type of instrument shall be defined and standardised during the detailed engineering phase and configured and stored in the templates as relevant for failure mode detection/shedding and PAS/IPS/IAMS configuration.

The use of Foundation Fieldbus (FF) on a relatively small number of I/O is not cost effective.

Analogue transmission of 4-20 mA with Smart "HART" protocol shall therefore be used for both non-safety and fast loops with a complex control strategy (e.g. compressor surge control) and for IPFs and F&G detection loops.

12.2.8.3. Measurement Accuracy

The required measurement accuracy shall be defined per instrument as per industry standards.

12.2.8.4. Electrical Safety in Explosive Atmospheres

The shore based part of the project is essentially defined as a safe area, however small hazardous areas shall exist around fuel storage and turbine engine fuel lines.

The Goldeneye platform has not been declared as hydrocarbon free and consequently there will be hazardous areas located on the platform.

Instruments installed in hazardous areas, shall have a relevant certification recognised by the Oil and Gas Industry and conform local legislation.

The design of the electrical apparatus, including instruments, instrument components and wiring components in hazardous areas shall be based on EEx(d)(flameproof) principles for Zone 1 and 2 applications and EEx(ia) (intrinsically safe) for Zone 0. EEx(e)(increased safety) is typically used for field junction boxes in Zone 1 or 2, that contain passive components only. Instruments installed in hazardous areas, shall have a relevant certification recognised by the Oil and Gas Industry and conform local legislation.

Test certificates from the following authorities are recognised for use in this Project:

- ATEX – Atmospheres Explosives (applicable within the European Community).

12.2.8.5. Instrumentation Selection and Installation

The selection of an instrument for a specific application is an iterative process, carried out as a joint effort of process and instrument engineers (from Engineering Contractor and EFA suppliers), with expert input from materials engineers, rotating equipment engineers and heat transfer engineers. The selection process of flow and level instruments, control valves and actuators for remotely operated on off valves shall be documented on standardised application notes for future reference.

All field devices shall have a minimum ingress protection rating of IP65 in accordance to IEC 60529.

Aluminium or anodized aluminium shall not be used for any part of an instrument or installation material used in the field.

12.2.8.6. Fire and Gas Detection

As part of the CCS project, a review of CO_2 detector technology has been completed. The review considered the potential effect upon detector operations from a CO_2 release (i.e. dense phase CO_2 release temperatures can drop to -78°C). As this could have a significant impact for safeguarding personnel and equipment.

The review of detailed tests carried out determined that the following types of CO_2 detection are suitable for use in the project:

- Line-Of-Sight detection;
- IR Point detection;
- Acoustic detection.

The above technologies have been considered as well as utilising an appropriate voting philosophy to increase the reliability of the detector system.

12.2.9. Alarm Management

The alarm system shall be designed for Onshore around Engineering Equipment and Materials Users Association practice and for Offshore the Shell DEP to limit the alarm rate such that the operator has time to understand the situation, initiate action and complete all of the other assigned tasks before new alarms arrive. The goal is to ensure that only alarms and event messages from unexpected, abnormal situations are sent to the operator. Target values are: on average less than two alarms per operator per hour, less than ten alarms following a trip and no single alarm in an operator domain contributes to the total number of alarms in that domain by more than 5%.

The work process for gathering the constraints and subsequently deriving the appropriate operating limits and corresponding notification settings, is referred to as Initial Set Up. The alarm management work process shall take place during the Execute phase of the project. It should be realised, that the required, full review of the limits and notification settings is a time consuming, team exercise.

The results shall be documented in the Site Alarm Philosophy, Variable Table and the Project Alarm Requirement Specification, covering the complete site. The study is likely to add, modify or remove alarms and will result in remedial measures, including alarm suppression, dead bands, time filters, etc. It's also feasible, that alarm only scenarios are not providing the required level of protection and may call for repeating elements from the HAZOP/DSR and may ultimately result in additional IPFs. CCS operators shall have benefits of the PCS Alarm Response Manual (ARM) database providing on-line prompts and assistance for each individual configured alarm. The offshore alarm database will require modification to reflect the modified process with its new and deleted alarms.

The measures resulting from the process alarm management study shall be detailed in the Project Alarm Requirement Specification produced in the Execute phase and will require ICSS logic and associated graphics for static/dynamic alarm suppression and mode depending alarm switching during abnormal operating conditions, process upsets, facilities start up and shutdown and transient operating modes. The redundancy requirements for alarm suppression triggers may result in additional measurements. Fast suppression logic for dynamic suppression may require implementation in the IPS. It should be realised, that alarm suppression techniques should be applied with great care to avoid the possibility of an alarm being inadvertently suppressed or left suppressed.

The Project Alarm Requirement Specification shall also include measures to suppress standing alarms of non-running equipment and for temporary alarm suppression/diversion during facilities construction and commissioning.

First out indication shall be applied where the occurrence of an event (e.g. compressor trip) is likely to cause a number of consequential alarms, which makes it unclear what caused the trip in the first place. The purpose of the first out indication is to capture the triggering event. First out indications are organised in groups around an object, such as a compressor.

The ICSS shall allow automatic "downloading" of configuration data and data from the Variable Table up to the start of FAT. Setting enforcement will not be applied after FAT, but auditing facilities shall be available to continuously compare and report on the actual settings against the "approved" settings in the variable table.

Trip and alarm setting information from all systems shall be available on line in the variable table. The settings and operator actions as listed in the variable table shall be available as a direct popup window as part of the ICSS alarm screen.

During the Execute phase, the requirements for alarm maintenance and testing shall be included in the Site Alarm Philosophy for every alarm point that is not covered by the SIL Assessment process.

Alarms that are not directly related to the facilities operation, such as device alerts, alarms and events (e.g. system alarms and most diagnostic alarms) shall by default be diverted to the IAMS systems.

13. Measurement Monitoring and Verification (MMV)

The selected storage site is assessed to be inherently safe; however, it is responsible to manage the residual storage risks no matter how small. MMV is central to the framework for storage risk management. There are two independent storage risks, loss of conformance and loss of containment and these are reflected in the two primary objectives of MMV for the Peterhead CCS Project.

1. Ensure Conformance to indicate the long-term security of CO_2 storage, i.e.
   a) Show pressure and CO_2 development inside the storage complex are consistent with models and, if necessary, calibrate and update these models;
   b) Evaluate and, if necessary, adapt injection and monitoring to optimize storage performance;
   c) Provide the monitoring data necessary to support CO_2 inventory reporting.

2. Ensure Containment to demonstrate the current security of CO_2 storage, i.e. Verify containment, well integrity and the absence of any environmental effects outside the storage complex:
   a) Detect early warning signs of any unexpected loss of containment;
   b) If necessary, activate additional safeguards to prevent or remediate any significant environmental impacts. Remedial actions are defined in a separate document, the Corrective Measures Plan (6).

Well-established industry practices for Well and Reservoir Management and Environmental Monitoring provide the key capabilities necessary to fulfil these requirements.

This section provides an overview only, with a focus on facilities design. The requirements may change as new technologies become available.

13.1. MMV Plan - Summary

13.1.1. Well Monitoring

Wells will have:

- Permanent down-hole gauges;
- Distributed Temperature Sensors (DTS) and Distributed Acoustic Sensors (DAS): based on fibre-optic technology.

Furthermore, well integrity wireline logging (cement bond, casing integrity); in well sampling; and sigma and neutron wireline logging are in the base monitoring plan. These however require the mobilization of a wireline to the platform to carry out the measurements.

13.1.2. Geophysical Monitoring

This includes time-lapse DAS VSP, 3D streamer survey, Ocean Bottom Nodes (OBN) near the platform: may require Remotely Operated Vehicle (ROV) access to place and remove nodes and/or cables. For the baseline seismicity survey 3 autonomous nodes will be used (not tied in to the platform). There is the potential to use the DAS cable for micro-seismic monitoring however this is still in the research and development stages.

13.1.3. Near-Surface Monitoring

For pockmark monitoring several Multi Beam Echo Sounder (MBES) and side scan surveys will be performed using a vessel or Autonomous Underwater Vehicle (AUV). Vessel deployed seabed sampling will be done with a Van Veen Grab or similar device. ROV bubble detection surveys will be performed as part of routine platform inspections.

Water column profiles may be measured by a Conductivity Depth and Temperature (CDT) probe beneath the platform which will be tied into the platform and possibly supplemented by an independent benthic lander away from the platform within the storage complex. The exact details will be finalized during the Execute phase.

13.2. Frequency

Baseline surveys before any injection activities commence are essential. For environmental sampling this may ideally take place several times before injection in order to understand seasonable variability of measurements. Surface seismic and MBES surveys are currently planned once prior to, during and post injection.

13.3. CO_2 tracers

The objective of injecting tracers in the CO_2 is to have an unambiguous differentiation of injected CO_2 from naturally occurring CO_2 in the area. The tracer should be monitorable for a long period of time, currently estimated at 50 years after end of injection.

It is recommended to inject tracers onshore at Peterhead downstream of the compressor. There is no requirement for offshore tracer technology. A skid mounted hydraulic driven metering pump is required will dose the tracer at surface into a suitable entry point into the pipeline at Peterhead. The pump would be set up to inject a tracer pulse for a given volume of flow.

Halocarbons, such as perfluorocarbons (PFCs) are currently the preferred type of tracer. PFCs are widely used in the hydrocarbon industry as tracers, and have also been used in CCS applications such as at Frio pilot. They are soluble in CO_2 and therefore easy to inject and are non-toxic with high thermal stability.

Further research will be required during the Execute phase to determine the exact tracer to use and to confirm its suitability with respect to the site specific geology. The injection volume requirements are in the order of ~1-10 ppb (total for 10 million tonnes of CO_2, 10-100 kg of PFCs).

14. Operations and Maintenance Philosophy

14.1. Operations Overview

The CCS End to End Operating and Maintenance philosophy covers the operating intent and required interfaces for the safe extraction, conditioning, transportation and injection of treated CO_2 to the Goldeneye reservoir. It outlines the required operations interfaces between SSE power plant and CCS capture plant.

PCCS will be operated totally independent to Block 1. CCS operations will be managed from an independent control building located within the CCS plot area. CCS process and utility areas will be clearly delineated to define areas of responsibility between Shell and SSE.

Site operations including command & control management plan developed during the Execute phase will be an agreed collaboration between SSE and Shell. The site emergency response management plan will define required interfaces and roles and responsibilities during any emergency event. SSE as site owners will take the leading role.

Goldeneye and pipeline operations will be fully remotely controlled from the PCCS control room via the ICSS.

14.1.1. CCS Operations

CCS operations are centred on the availability of flue gas from PPS GT13, the operation of steam turbine ST20, the supply of essential utility services required to support operations and the availability and uptime of the offshore Goldeneye pipeline and platform facilities. Outages of any of this equipment will have varying severity depending on the system concerned with the greatest resulting in immediate CCS shutdown.

Onshore CCS extraction and compression is divided into three processing elements, the PPS scope which includes the HRSG and selective catalytic reduction unit, the CCP containing the flue gas booster fan, direct contact cooler, amine CO_2 absorber & CO_2 stripper, amine storage and amine pumping systems and the conditioning and compression system containing the multistage centrifugal compressor package, molecular sieve dehydration and CO_2 metering. The design is such that there is no sparing of any of these packages and failure of any one, or a combination of, will result in processing downtime and/or shutdown.

Well management and CO_2 injection control will be automated through the integrated Goldeneye/CCS ICSS system. The ICSS will be configured with individual well operating envelopes to maximise CO_2 delivery whilst maintaining operating integrity within allowable pressure constraints.

Normal operations will seek to maintain pipeline pressure close to the design maximum allowable working pressure, this will provide adequate pipeline buffer volumes for up to two hours operation at reduced flow should there be a delivery problem form the onshore CCS plant.

Incipient equipment failings will be identified and engineered against recurrence. Work processes, procedures, safety management and operational management systems will lever on best practices and synergies currently in use by Shell and SSE.

14.1.2. Goldeneye Operations

Goldeneye is classified as a Normally Unattended Installation (NUI). It is operated to industry norms of a NUI facility where operational visits are minimised by optimising maintenance and scheduling operational activities to coincide with mandatory platform and ad-hoc visits which occur from time to time.

Normal design occupancy frequency is quarterly (12 weeks), coinciding with the available diesel storage volumes required for the on-board power generators. Problems associated with fuel oil contamination and sludge deposition in the storage tank has reduced the effective usable volume of clean diesel, resulting in increased occupation. At present the diesel oil storage tank is topped up every eight weeks and the intent once these restrictions are overcome is to extend this time interval to between 10 and 12 weeks thus providing an avenue for annual OPEX saving and of course improved HSE brought about by reduction in exposure to travel by helicopter.

Specific injection related data will be linked into company well engineering management systems. It is anticipated in the early years of operation, only one injection well will be in use at any one time with the exception when dictated by operational constraints or malfunction where a second or third may be required. Later field life will require a two well operation.

Goldeneye has no physical processing capabilities. Topside equipment is limited to the pig receiver, inlet filtration, flow line monitoring, vent drum and low temperature vent stack.

The inlet filtration will consist of a pair of instrumented fine mesh filters, typically 5 micron with remote changeover capability.

The pig receiver will be used for initial pipeline commissioning and inspection and thereafter every five to six years for intelligent pig data acquisition.

Initially during first start-up there is a high probability wells will hydrate, mitigation will be by methanol injection to the well and tubing. The existing methanol pipeline from St Fergus is being retained to facilitate this.

Hydrocarbons will always be present in the production tubing of the monitoring well; therefore Goldeneye will remain classified as a hydrocarbon facility.

CCS operations will not materially change existing NUI operations. Personnel will be competent and trained in well operations, CO_2 injection and utility operations as well as those mandated for platform operations such as OIM qualifications, Helicopter Landing Officer, Medic & First Response and Fire Team

14.1.3. Process Operations

14.1.3.1. Normal Operations

Normal operations are defined as when the CCS plant in its entirety is operating at optimum efficiency and producing contractual volumes of CO_2 at the required specification and injected into the Goldeneye reservoir in accordance to the design premise.

This also includes ancillary process systems, equipment and utilities required to support operations and which may not necessarily be required to be fully functional on a daily basis, but their prolonged downtime would result in a process shutdown such as the Thermal Oxidizer.

14.1.3.2. Upset Conditions

Upset conditions may occur either at the supply of exhaust product to CCS or within the CCS processing and transportation chain. Consequence of any upset varies depending on origin and duration. PPS upset conditions excluding any obvious such as main power failure may arise due to failure of GT13, ST20, HRSG13 and condensate system, whilst those for CCS injection may occur within the amine plant, compression and dehydration, pipeline or Goldeneye.

Restart times for any of these 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 the power plant. 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 noted in Table 14-1 below.

Table 14-1: Shutdown Indicative Re-start Times

Condition	Restart Time (mins)
GT13 Cold Start (PPS Offline >16hrs)	~ 90
GT13 Warm Start(PPS Offline >6<16 hrs)	~ 60
GT13 Hot Start (PPS Offline<6hrs)	~ 50
ST20 Cold Start	~ 110

Condition	Restart Time (mins)
ST20 Warm Start	~ 50
ST20 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 pipe line pack to operate for approximately two hours at this minimum flow, before pipeline shutdown is called upon.

14.1.4. Organisation & Personnel Manning

The operating model is based on an integrated CCS/Goldeneye operations and maintenance team located at the CCS plant in Peterhead and supported by management and discipline engineering from Shell St Fergus & Aberdeen.

Base case CCS staffing will comprise of an onsite Shift Supervisor and Technical Process Engineer with the remaining O&M personnel subcontracted through a third party entity(s). This concept is not fully finalised and may be subject to revision as the project matures.

Offshore operations will largely remain unchanged with competent personnel seconded from within the operations organisation to support as and when required. There will be no change to the existing manning philosophy other than those required to support CO_2 process operations such as personnel competency in a CO_2 environment, emergency response practices and the likes.

Commissioning, Start-up and on-going operations will be managed by selection of experienced and competent personnel from the hydrocarbon, chemical and utility industries. Specific job profiles will be developed for each position and individuals will be made competent by appropriate training and assessment. If required, the opportunity will be taken to train operators at the St Fergus plant in preparation for CCS start-up.

14.2. Monitoring and Control Requirements (And Metering)

14.2.1. Integrated monitoring & Control Strategy

The operating requirement is of a fully integrated end to end CCS monitoring and control capability from the PCCS control room at the CCS capture plant and remote/local capability at Goldeneye.

This shall be based on a fully Integrated Control and Safeguarding System (ICSS) comprising of the Distributed Control System (DCS) and safety systems for Emergency Shutdown (ESD) and Fire and Gas Detection and Activation (F&G). The design intent is to provide a safe, easy to operate, highly reliable, self-checking control and instrumented system which requires minimum maintenance and provides the means to remotely monitor, control and operate the facilities.

The ICSS/HMI will have the necessary functionality to monitor and control the whole process from outlet of the HRSG unit at PPS through to final injection at Goldeneye. SSE power plant status and any functional control requirements/interfaces will be made available to the ICSS. The ICSS with its standard algorithms will be used for control function, switching, indication and data archiving where required. Control functionality will be agreed by operations. The ICSS will have capabilities to communicate with Goldeneye ICSS system

All necessary process and utility parameters will be gathered through the ICSS system to provide the control room operator with an overview of the field operation. The system will be designed to have minimum attendance on the plant when all the systems are proven and commissioned.

The ESD system will communicate with the ICSS system giving status of initiators, overrides and system functions. These will be displayed within the operator station graphics.

Major or critical plant will be capable of being started, controlled and stopped from the control room and will also be provided with shutdown facilities local to the plant.

PC based historical data trending and archiving of alarm and event logging will be provided as well as software interfaces external to the ICSS.

14.2.2. Goldeneye Integrated Monitoring & Control & ESD

Goldeneye process and utility systems will be continuously monitored and controlled from the PCCS control room and local to Goldeneye when occupied. Normal operations and control will virtually remain unchanged to that previously seen when operated as a hydrocarbon platform other than in this case wells are injecting rather than extracting fluids.

Day to day plant management and control will be through the ICSS and its Human Machine Interfaces. The likelihood of operator error is to be minimised by maximising auto start-up/and shut-down sequences. Where beneficial ICSS algorithms will be developed to cover all aspects of operations from initial start-up, normal operations, abnormal operations, well start-up and shutdowns, process plant shutdown and blow downs.

Specific issues operating dense phase CO_2 and the potential under adverse conditions of cold temperature fractures are addressed in the process safeguarding system to ensure facilities are operated within their design envelopes. Deviations from acceptable limits are managed through the facility ESD.

Process and Utility plant isolation and depressurisation will be initiated through systematic isolation of plant into discrete containment zones which may, depending on the severity of the disturbance initiate depressurisation of the locked-in inventory. Under normal shut down operations CO_2 will be locked in, there will be no blowdown.

Goldeneye well and reservoir management philosophy is to ensure optimal CO_2 injection to satisfy contractual obligation while maintaining overall system integrity (wells, reservoir and facilities). This will be established through active monitoring of the wells and reservoir from initial operations through acquisition of baseline data during the work over operations and continuous acquisition of pressure, temperature and other required data in the wells and reservoirs. Acquired data will be used to calibrate well and reservoir models for active well and reservoir monitoring.

14.2.3. Plant and Equipment Monitoring (General)

Field instrumentation will be optimised for safe and reliable operations. Transmitters will be used in preference to switches to initiate trip signals. Non-intrusive instrumentation will be used wherever possible. The opportunity to include 'smart' instrumentation will be investigated and installed where there is a proven benefit to maintaining high levels of production availability matched against capital cost.

Major or critical rotating equipment will be provided with appropriate health monitoring, surveillance and diagnostic capabilities which will include permanent vibration monitoring and vendor remote diagnostic capability.

Where permanent vibration monitoring is deemed uneconomical or not necessary due to the lower risk of equipment defect, periodic monitoring will be undertaken by hand held devices. Monitoring points will be identified during Detailed Design for inclusion in the facility asset maintenance plan.

Equipment classified as safety critical and which have assigned performance standards such as Tight Shut Off (TSO) valves or equipment identified, whether rotating or static, whose operating efficiency is directly related to delivery of product volume, will be provided with the means to determine its operating performance. Ideally this will be non-intrusive such as permanently installed orifice plates, pressure gauges, temperature transmitters and electric motor power meters.

14.2.4. Shutdown and Safeguarding (ESD)

14.2.4.1.1. CCS ESD

The CCS plant will be equipped with an integrated ESD system, to ensure the safety of personnel and protection of equipment by isolation and shutdown of all or part of the facility under process fault or fire conditions. The system will be designed, manufactured, tested and commissioned to comply with the requirements of IEC 61508.

Emergency shutdown strategy is structured on minimising hazards by minimising inventory and by isolation of the process plant into discrete containment/depressurisation zones. The ESD system will initiate on demand safe isolation and shutdown of equipment under safety related process trip, fire detection or flammable/toxic gas detection. The ESD system will ensure the safe isolation of non-essential electrical equipment (removal of source of ignition) which may be associated in the hazard area.

The ESD system will only consist of the higher level shutdown initiating event, unit process shutdowns should be initiated wherever possible within the ICSS.

Levels of shutdown are defined in the ESD philosophy and consist of 4 levels. Level 2 – 0 are considered as ESD applications, whilst Level 3 will be an ICSS function:

- Level 3 Local Process shutdown;
- Level 2 Local equipment or area shutdown;
- Level 1 Process Facility shutdown;
- Level 0 Total process shutdown and isolation of wellheads and pipelines.

All necessary interfaces required to ensure the control room operator has full field overview status will be provided. The ESD system will communicate with the ICSS system giving status of initiators, overrides and system functions. These will be displayed within the operator station graphics.

Pressurised sections of the plant will be subdivided into Emergency Shutdown System (ESD) and Emergency Depressurisation (EDP) zones to meet the requirements of the safety and O&M philosophies. Process and utility plant isolation and depressurisation will be initiated through systematic isolation of plant into discrete product containment zones which depending on the severity of the disturbance initiate depressurisation of the locked-in inventory. Shutdown and consequence matrices will be developed during Detailed Design which will form the basis for overall plant safeguarding management

The ESD system will also allow the operator to manually initiate the emergency depressurisation of the high-pressure gas system. ESD valves will be designed with local manual pushbuttons for resetting the valve after shutdown. In addition to the automatic operation, manual shutdown initiating pushbuttons (located in PCCS control room) will be provided. These pushbuttons will be protected against inadvertent operation by hinged covers. The authorised operator in the PCCS control room will be provided with supervisory control over shutdown reset operations.

14.2.4.2. Goldeneye ESD

The ESD is integrated into the Honeywell Safe Guarding System (SGS) containing ESD, Fire & Gas (F&G) and Emergency Depressurisation and Blow down (EDP). The SGS is integrated yet independent to the Honeywell ICSS, although alarms and their resultant effects are displayed on the main process control system. The existing Goldeneye ESD will be upgraded to incorporate process changes necessary for CCS operations. The ESD has the following features:

- All automatic process: shutdowns parameters have pre-alarms to permit possible avoidance of shutdown by operator intervention;
- The ESD system will allow the operator on demand to manually initiate an emergency depressurisation (EDP) of the process; and
- ESD valves are designed with local manual pushbuttons for resetting the valve after shutdown. In addition to the automatic operation, manual shutdown initiating pushbuttons (located in PCCS control room) are provided.

Note: Goldeneye ESD valves will be modified to incorporate local & remote re-sets, subject to completion of an appropriate Risk Workshop. This is a deviation from the existing process. In light of the new risks associated with handling CO_2 and the consequence of a prolonged delay mobilising to the platform, remote resetting is seen as a safer and more viable mode of operations.

14.2.4.3. Fire and Gas

The integrated F&G will interface with the respective ESD system to ensure safe shutdown of plant and equipment as required by any confirmed F&G detection initiation. The F&G will automatically initiate fire protection systems, if required, and also indicate on the respective screens/panels any initiation events such as detector location, fire pumps running, deluge valve activation and the likes. The system shall utilise well proven techniques to incorporate redundancy, self-checking and fault identification features.

Detector devices shall include flammable gas, Line of Sight (LOS), smoke, UV, IR and CO_2 detectors. The detection system will be supplemented by manual call points strategically sited around the facilities buildings and process units.

Admin buildings, workshops, stores and other non-essential areas may be protected by standalone modular protection systems.
The existing Goldeneye Fire and Gas System and Cause & Effects charts will be upgraded to incorporate those changes required for toxic CO_2 detection.

14.2.5. High Level Metering Strategy and 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 & 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.

Further details for metering strategy are presented in KKD 11.077 - Surveillance Metering and Allocation Strategy and Design Package [5]

14.2.5.1.1. 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 since 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.

14.2.5.2. 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.

14.2.5.3. EU ETS Compliance Strategy

The proposed strategy for compliance with the EU ETS regulations is that the Project will be considered as three separate installations, 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).

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.

For CCS application, the EU ETS regulations require reporting of greenhouse gases that are transferred:

1. From the power plant to the CCCC plant, and;
2. From the CCCC plant to the offshore installation.

To facilitate the required greenhouse gas reporting, flow meters with the necessary composition analysers will be fitted within the capture plant installation to determine CO_2 flows:

1. At in the inlet duct to the CCP booster fan, and;
2. After the CO_2 compression prior to the inlet to the offshore pipeline.

Measurement of CO_2 flow in the inlet duct to the CCP booster fan, to the accuracy required for EU ETS, is technically challenging. The Project's preferred approach to determining the quantity CO_2 transferred to the capture process is to use the assumption that 100% of GT13's exhaust stream will be transferred to the capture plant, such that the transferred CO_2 value is equated to the CO_2 emission calculated from complete combustion of the fuel, as metered at the GT13 fuel inlet. The assumption is considered reasonable as the quantity of GT13's flue gas directed through the 90 m stack, when operating in abated mode, is anticipated to be insignificant and, in any event, could be considered as attributable to operation of the capture plant. However, for other times including operating in unabated mode, no flue gas is transferred. For these instances, GT13's fuel metering is no longer representative of transferred CO_2 and the value for transferred CO_2 will be set to zero.

A direct measurement of flue gas flow at the capture plant inlet will still be provided and this will be used to corroborate the values calculated from GT13's fuel consumption and to confirm the operating mode of the plant.

The installation strategy for the onshore scope of work is still subject to agreement between SEPA, Shell and SSE and requires the preparation of detailed monitoring plans in the next phase of the project.

14.2.5.4. PPC Metering Compliance Strategy

The existing Peterhead Power Station site has a Pollution, Prevention & 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 remaining 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.

14.2.6. Utilities & Processing Fluids

CCS operations utilise a number of process chemicals; the principle fluids being amine, sulphuric acid, sodium hydroxide and ammonium hydroxide. Initial volumes required for first fills are substantial especially for the amine first fill where a large number of road tankers will be required. Crucial to this cause is a competent logistics and transportation process to maximise transportation efficiency.

All chemicals and fluids are subject to a mandatory risk assessment process to assess their handling, storage and disposal requirements in accordance to their COSHH recommendation.

Used and spent fluids will be disposed via registered companies in accordance with the approved code of practice.

Table 14-2: Expected Chemical Inventories of CCS plant

Substance	Capacity (Litres)	Use
Diesel Oil	33,600	Auxiliary Boiler, Emergency Generator
Hydrogen	500	Compression Plant
Lub oil/hydraulic oil/transformer insulating oil	100,000	Compressor & Transformers
Sulphuric Acid (98%)	50,000	Gas Pre-Treatment Plant
Sodium Hydroxide (47%)	50,000	Gas Pre-Treatment Plant
Ammonium Hydroxide (25%)	75,000	Gas Pre-Treatment Plant
Fresh Amine	723,000	Carbon Capture Plant
Lean Amine	2,086,000	Carbon Capture Plant
Degraded Amine Product	113,000	Carbon Capture Plant
Waste Water Treatment Chemicals	Under Development	WWTP
Tracing Chemicals	Under Development	Compression Plant

The only process fluid in use on Goldeneye is methanol which is used to safeguard against possible hydrates for displacing the liquid CO_2 from the upper tubing after the well is closed in following a shutdown. The required volume is relatively small, circa 6 m^3 supplied via the 4 inch (102 mm) St Fergus Methanol pipeline (previously MEG pipeline).

Part of the existing St Fergus MEG system will be upgraded and changed for methanol storage and pumping. The existing St Fergus to Goldeneye MEG pipeline is retained for methanol use.

Utility fluids are restricted to diesel fuel for the power generators and crane engine and hydraulic oil for the wellhead and subsea hydraulic system.

14.3. Reliability, Availability and Maintainability (RAM)

During FEED, a RAM study was undertaken create a full PCCS end to end reliability model. The RAM study is used to quantify the overall reliability and availability of the project. The RAM model also aids to identify critical systems/components and events responsible for plant unavailability and the recommendations on how to achieve target availability, if necessary.

PCCS performance parameter are summarised in Table 14-3 below:

Table 14-3: CCS Project Key Performance 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 %. Annual average availability over the 15 year project life are shown in the following Table 14-4. The highest contributors to the full PCCS unavailability are the PPS station outages for gas turbine GT13 scheduled maintenance. See Table 14-5 for the schedule of gas turbine inspections.

The following factors are identified which may influence delivery capability:

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 & 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.

Onshore

- Single export compressor;
- Single flue gas booster fan;
- 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. Sensitivity analysis will be conducted further during FEED to evaluate the impact of any sparing requirements;
- GT13 maintenance outage.

Table 14-4: Target Project Annual Availability

Time	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Avail %	79.5	89.1	89.1	79.8	88.0	89.1	79.3	89.3	88.5	79.6	89.2	89.0	77.2	89.0	89.1

Table 14-5: GT13 Scheduled Maintenance Outages

		Frequency (years)	Year Scheduled	Downtime Duration (hrs)
GT-13	GT Life Time Extension	12	2031	1368
	GT Major Inspection	6	2025	1176
	GT Hot Gas Path Inspection	3	2022	960
	GT Combustion Inspection	1	2019	240

CCS asset maintenance outages will be aligned to that required by SSE power plant, thus maximising overall plant availability. SSE planned maintenance outages are required for inspection and servicing of the GT13, ST20 and the HRSG13.

The offshore contribution to down time is relatively small, <4.5 % with the greatest contribution emanating from the riser, control and ESDV valves. The design has already improved on the main inlet process control valve by incorporating a second valve in line with the upstream filter. The only remaining improvements which are outstanding from past operations is clean up of the diesel fuel system which is known to have a contaminated storage tank and the installation of a diesel polishing filter/coalesce for circulating and cleaning the storage tank. This will reduce the likelihood of a repeat of microbial degradation in the diesel storage tank.

14.4. Operability & Maintainability

14.4.1. CCS Operability and Maintainability

A provisional end to end Plant Operability & Maintainability study has been completed to ensure and confirm the facilities in their entirety are capable of delivering product volumes in accordance to contractual agreements:

- Plant capacity is appropriate to fully meet all product contractual agreements;
- Appropriate and adequate isolation which minimises CAPEX, and plant disruption whilst maintaining isolation to industry standards;
- Provision of adequate walkways, platforms and pathways to facilitate safe operations;
- Provision of adequate roads and lay down areas for vehicle safe access.

Initial assessment confirms the design is appropriate and there is adequate access for equipment. This is confirmed by observation of the 90 % stage 3D model during FEED, recognising that the model as seen cannot truly depict the exact arrangement of roads, hard standing, flange details and vessel internal accessibility arrangements. Further assessment will be required during Detailed Design when the model is fully completed and is truly representative of final design and configuration.

Process operations is reviewed and assessed to be appropriate, again recognising the assessment is based on information provided on PEF drawings and data sheets. Equipment found in the CCS capture plant such as the very large main inlet booster fan, compressors and the amine are not unique in industry but novel in the oil and gas sector, and their operation and maintenance will require additional training and support. Operations will need to ensure all risks are mitigated by appropriate isolation, procedures and safe work practices. In particular the handling of the amine and its more toxic degradation products, which are concentrated in the thermal reclaimer units, will need to be covered by detailed operating procedures.

The isolation philosophy is consistent to industry standards and provides the level of protection required for the safe isolation of plant and equipment.

Storage tanks and vessels requiring filling are provided with the appropriate transfer stations and safety features such as bund areas, drains, runoff and fire & deluge water protection, where required chemical showers and spill containment are provided.

14.4.2. Goldeneye operability and maintainability

The Goldeneye layout design will largely remain unchanged apart from that required to locate the pre-injection duplex cartridge CO_2 filter located adjacent to the well bay area and the low temperature CO_2 vent which is positioned alongside the existing vent in the vent stack. Provision is made to access the CO_2 filters for cartridge change out.

The change from a hydrocarbon fluid to inert CO_2 has operations implications especially in the case of a major pipe fracture where the lower platform areas down to sea level may be shrouded in CO_2 cloud which may impair conventional evacuation routes to sea and / or to helicopter. Further studies will be required to assess any change in operational requirements with regards to the design of Temporary Emergency Refuge and the use of lifeboats in the event of emergency evacuation by sea.

An initial assessment has confirmed the impact to Goldeneye for CCS operations is negligible to that when operated as a hydrocarbon facility. The greatest change lies in ensuring personnel are competent in working with CO_2 and have a thorough understanding of the nuances of CO_2 in comparison to hydrocarbon processing.

Access to the pig receiver, wellhead tree valves and the new filters has been assessed and is deemed appropriate for Operations.

14.5. Sparing, Insurance Spares and Spare Parts

14.5.1. Sparing

An initial Reliability Availability & Maintainability (RAM) model has been developed to support and optimise the basis of design. The design has eliminated sparing of the larger capital equipment such as the main inlet booster fan and the gas compressor. These in addition to vessels, coolers and tanks constitute single point failures which will require adequate mitigation to ensure downtime and repair times are minimised.

All other rotating equipment is spared and provided with appropriate isolation valves to effect online repairs. The toxicity of fluids such as the amine and reclaimer waste will impact how this is achieved in practice and is subject to further studies and discussions.

For basis of design purposes the following is used which will be subject to changes as the project evolves.

- Design compliant to industry best practice (Shell DEP standards partial compliance);
- Pumps, Fans, and ancillary equipment :- 100% sparing unless otherwise noted;
- Main Process Vessels and Towers :- No sparing;
- Export Compressor :- No sparing;
- Utility Supplies (to be supplied by SSE) *(Availability to be confirmed during Detailed Design).*

Note: Goldeneye will largely remain as per current design, 3 wells used for injection, 1 well for monitoring, 1 well abandoned, CO_2 filters 2 x 100 %.

The provision of dual CO_2 filters and dedicated inline pressure/flow control valve coupled with the availability of three injection wells provide adequate process flexibility and should result in high injectivity uptime.

The two methanol pumps at St Fergus coupled with the knowledge methanol is only required for short durations following a well shutdown provides ample mitigation against well hydration.

14.5.2. Spare Parts Philosophy

The effectiveness with which operations success is measured is largely governed by the plant uptime which in turn is reliant on the ability to maintain plant and equipment at their optimum operating condition. Spare parts and the availability of spares is a major contributor to this and accordingly the spare parts philosophy is a key deliverable during design to ensure spare parts selection is appropriate and which takes cognisance of regional availability and manufacturer lead times. The spare parts philosophy shall take full cognisance of equipment availability and uptime requirements including specific needs such as maintenance of safety critical elements. Analysis of these requirements is based on reliability centred maintenance techniques taking into consideration replacement time and lifecycle costing for each of the components. This will be one of the primary selection criteria for major machinery and equipment purchase.

Consistent with Company and industry practice, spare parts categorisation shall follow industry norms of Commissioning and Start-up Spares, Operating Spares (2 Years) and Capital Spares. Operations will play a lead role in spare parts management and will influence engineering and contractor in ensuring appropriate selection and quantities of spares are provided by the project. Where possible equipment selection shall seek to standardise sizing to maximise equipment interchange-ability, thus minimising spare parts stock holding. The standardisation shall be in accordance with Shell's guidelines and practices.

Vendors and manufacturers shall be responsible to deliver and code spares electronically in a format suitable for uploading to the SAP management system. The electronic Spare Parts Interchange-ability Records (E-SPIR) shall be reviewed by operations to ensure optimum spare parts holding taking into consideration the number of interchangeable equipment, the delivery lead time and cost impact on project economics.

The initial operating spares and special maintenance tools shall be available on site prior to handover from Contractor to Company. An audit shall be conducted on the status of all spare parts prior to the handover.

A SAP warehouse and stock management system will be developed and operational prior to equipment commissioning in preparation for acceptance of the 2 year operating spares, capital spares and remnants of any vendor/project commissioning and start-up spares.

14.5.3. Capital Insurance Spares

Capital spares are high cost insurance spares which are capitalised against the project. These capital / insurance spares are those spares of major equipment assemblies or complete items of equipment that are required for items not normally subject to deterioration by normal use, but on failure replacement is critical for continuous safe operation. Preliminary screening has identified the following assets requiring capital spares:

CCS

1) CO_2 Export Compressor (K-3101-3106);
   - Main Gearbox Assemblies
   - Compressor Inter-stage & Pinion Wheels
2) Inlet Booster Fan (K-1001A) (Shaft); and
3) Coolers and exchangers (tubes only).

Goldeneye

Preliminary screening has identified the requirement for offshore lies with well engineering for the wellhead trees and sub-surface completions and possibly the subsea manifold emergency shutdown valve. Well engineering normally include a percentage of sparing when placing initial purchase orders for wellheads and production tubing, this is the industry practice to minimise work-over/drilling delay due to material shortage which would result in extensive additional rig costs.

Well engineering will confirm their requirements during Detailed Design.

15. Bibliography

[1] KKD 11.058 - Scope of Work for Execute Contracts.

[2] KKD 11.133 - FEED Summary Report.

[3] KKD 11.001 - The Basis of Design.

[4] KKD 11.020 - FEED Decision Register.

[5] "KKD 11.077 - Surveillance Metering and Allocation Strategy and Design Package".

[6] KKD 11.064 - Technology Maturation Plan.

[7] KKD 11.023 - Risk Management Plan and Risk Register.

[8] KKD 11.019 - FEED Lessons Learned Report.

[9] KKD 11.043 – Cost Estimate Report.

[10] PCCS-00-TC-AA-6627-00001, Peterhead CCS (Onshore) Interface Schedule - APPENDIX 1.

[11] PCCS-01-TC-PX-5527-00001, Process Description (CCS Project "Generation Facilities") - APPENDIX 2.

[12] PCCS-01-TC-PX-2365-00003-001, Process / Utilities Engineering Flow Scheme - Heat Recovery Steam Generator Exhaust Gas System - APPENDIX 2.

[13] PCCS-01-TC-PX-2366-00001-001, PFS - Aqueous Ammonia Storage and Transfer to SCR System, - APPENDIX 2.

[14] PCCS-01-TC-PX-2366-00003-001, Process Flow Scheme Condensate Polishing and Feed Water Tank, - APPENDIX 2.

[15] PCCS-01-TC-PX-2366-00004-001, Process Flow Scheme Generation Facilities HRSG 13 & ST13, APPENDIX 2.

[16] PCCS-01-TC-PX-8240-00001, Heat and Material Balance (Generation Facilities), - APPENDIX 2.

[17] PCCS-01-TC-PX-2365-00025-001, Main and Auxiliary Cooling Water System, - APPENDIX 2.

[18] PCCS-01-TC-PX-2366-00002-001, "UTILITY FLOW SCHEME SEA WATER DISTRIBUTION SUPPLY AND RETURN," - APPENDIX 2.

[19] PCCS-01-TC-EA-2384-00001, Unit 20 Generator One Line Diagram, - APPENDIX 2.

[20] PCCS-01-TC-EA-2384-00002, Unit 20 HV One Line Diagram, - APPENDIX 2.

[21] PCCS-01-TC-EA-2384-00003, Unit 20 LV One Line Diagram, - APPENDIX 2.

[22] PCCS-02-TC-PX-8240-00001, Heat and Material Balance, - APPENDIX 3.

[23] PCCS-02-TC-AA-4322-00001, Equipment Summary List, - APPENDIX 3.

[24] PCCS-02-TC-PX-2366-00001-001, Process Flow Scheme - Flue Gas Pre-Treatment, - APPENDIX 3.

[25] PCCS-02-TC-PX-2366-00002-001, Process Flow Scheme - CO2 Absorption, - APPENDIX 3.

[26] PCCS-02-TC-PX-2366-00003-001, Process Flow Scheme - Amine Handling, - APPENDIX 3.

[27] PCCS-02-TC-PX-2366-00004-001, Process Flow Scheme - Amine Regeneration, - APPENDIX 3.

[28] PCCS-02-TC-PX-2366-00005-001, Process Flow Scheme - Ion Exchange Package, - APPENDIX 3.

[29] PCCS-02-TC-PX-2366-00006-001, Process Flow Scheme - CO2 Amine Thermal Reclaimer No.1, - APPENDIX 3.

[30] PCCS-02-TC-PX-2366-00007-001, Process Flow Scheme - CO2 Amine Thermal Reclaimer No.2, - APPENDIX 3.

[31] PCCS-02-TC-PX-2366-00008-001, Process Flow Scheme - CO2 Amine Thermal Reclaimer No 3, - APPENDIX 3.

[32] PCCS-02-TC-PX-2366-00009-001, Process Flow Scheme - Compression & Conditioning - 1, - APPENDIX 3.

[33] PCCS-02-TC-PX-2366-00010-001, Process Flow Scheme - Compression & Conditioning - 2, - APPENDIX 3.

[34] PCCS-02-TC-PX-2366-00011-001, Process Flow Scheme - Dehydration Package, - APPENDIX 3.

[35] PCCS-00-TC-MP-4024-00002, Peterhead Overall CCCC Project Area Plans, - APPENDIX 1.

[36] PCCS-02-TC-PX-2366-00021-001, Utility Flow Scheme - LP Steam & Condensate System, - APPENDIX 3.

[37] PCCS-02-TC-PX-2366-00022-001, Utility Flow Scheme - Sea Water and Cooling Water System, - APPENDIX 3.

[38] PCCS-02-TC-PX-2366-00023-001, Utility Flow Scheme - Effluent Systems, - APPENDIX 3.

[39] PCCS-02-TC-PX-2366-00024-001, Utility Flow Scheme - Instrument Air System, - APPENDIX 3.

[40] PCCS-02-TC-PX-2366-00025-001, Utility Flow Scheme -Demin, Drinking and Service Water System, - APPENDIX 3.

[41] PCCS-02-TC-PX-7180-00005, Utility Requirement Report / Utility Summaries, - APPENDIX 3.

[42] PCCS-02-TC-IN-6604-00001, ESD Cause and Effects Carbon Capture and Storage

(Onshore), - APPENDIX 3.

[43] PCCS-02-TC-EA-2384-00001, Substation ESS-3000 One Line Diagram, - APPENDIX 3.

[44] PCCS-02-TC-EA-2384-00002, Substation ESS-2000 One Line Diagram, - APPENDIX 3.

[45] PCCS-04-PT-PX-2366-01001-001, Process Flow Scheme, Goldeneye Topsides Facilities for Carbon Storage, - APPENDIX 5.

[46] PCCS-06-SUB-PX-2366-00007-001, Overall System Process Flow Scheme, - APPENDIX 4.

[47] PCCS-06-SUB-PX-2365-00001-001, Process Engineering Flow Scheme Symbols and Legend, - APPENDIX 4.

[48] PCCS-06-SUB-PX-2365-00002-001, Onshore Pig Launcher Process Engineering Flow Scheme, - APPENDIX 4.

[49] PCCS-06-SUB-PX-2365-00003-001, SSIV Process Engineering Flow Scheme, - APPENDIX 4.

[50] PCCS-06-SUB-LA-4024-00001-001, Overall Field Layout, - APPENDIX 4.

[51] PCCS-06-SUB-LA-4018-00006-001, HDD Shore Approach Plan Route and Longitudinal Profile, - APPENDIX 4.

[52] PCCS-04-PTD-PX-2366-01001-001, Offshore Process Flow Scheme Shell Goldeneye Topsides Facilities for Carbon Storage, - APPENDIX 5.

[53] PCCS-04-PTD-PX-2366-00001-001, PFS Offshore Process Flow Scheme Goldeneye Flows Compositions and Operating Conditions, - APPENDIX 5.

[54] PCCS-04-PTD-PX-2365-20000-002, Process Engineering Flow Scheme CO2 Filters, - APPENDIX 5.

[55] PCCS-04-PTD-PX-2366-40001-001, Offshore Utility Flow Scheme Goldeneye Storage General Utilities for Carbon Storage, - APPENDIX 5.

[56] PCCS-04-PTD-PX-2366-50001-001, Offshore Utility Flow Scheme Goldeneye CO2 Venting Systems, - APPENDIX 5.

[57] PCCS-04-PTD-PX-2366-50002-001, PFS Goldeneye Wellhead and Lubricator Vent System, - APPENDIX 5.

[58] PCCS-04-PTD-PX-2365-10000-003, Utility Engineering Flow Scheme ZG Hydraulic Power System, - APPENDIX 5.

[59] PCCS-04-PTD-PX-2365-50000-001, Utility Engineering Flow Scheme Well Bleed off Manifold Arrangement, - APPENDIX 5.

[60] PCCS-04-PTD-PX-2365-50000-002, Utility Engineering Flow Scheme ZG Vent System, - APPENDIX 5.

[61] PCCS-04-PTD-PX-2365-59000-001, Utility Engineering Flow Scheme ZG Nitrogen System, - APPENDIX 5.

[62] PCCS-04-PTD-PX-2365-61000-001, Utility Engineering Flow Scheme ZG Drains System,

T60010, - APPENDIX 5.

[63] PCCS-04-PTD-PX-2365-73000-001, Utility Engineering Flow Scheme ZG Chemical Injection System for CCS Project, - APPENDIX 5.

[64] PCCS-07-PTD-MP-4363-00001, Tie-In List and Schedule (Methanol at St. Fergus), - APPENDIX 4.

[65] PCCS-01-MM-CX-4018-0001, Peterhead CCS A90 Main Site Access Proposed New Layout - General Arrangement Plan, - APPENDIX 2.

[66] PCCS-01-MM-CX-4018-0002, General Arrangement Plan, - APPENDIX 2.

[67] PCCS-01-TC-IN-6604-00001, ESD Cause and Effects Peterhead Power Station, - APPENDIX 2.

[68] PCCS-00-TC-IN-0901-00001, PAS / ESD / F&G Architecture/ Block Diagram, - APPENDIX 1.

16. Glossary of Terms

2oo3	two--out--of--three
3D	3 Dimensional
3LPE	three layer polyethylene
AC	Alternating Current
ALARP	As Low As Reasonably Practicable
Ar	Argon
ARM	Alarm Response Manual
ASME	American Society of Mechanical Engineers
ATEX	Atmospheres Explosives
AUV	Autonomous Underwater Vehicle
BDEP	Basic Design Engineering Package
BfD	Basis for Design
BOD	Biological Oxygen Demand
$CaCO_3$	Calcium Carbonate
CAD	Computer Aided Design
CAPEX	Capital Expenditure
CB	Circuit Breaker
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
CfD	Contract For Difference
CFD	Computational Fluid Dynamics
CIBSE	Chartered Institution of Building Services Engineers
CITHP	High closed-in tubing head pressure
CH_4	methane
CO	Carbon monoxide
CO_2	Carbon dioxide
COD	Chemical Oxygen Demand
CoP	Cessation of Production
COSHH	Control of Substances Hazardous to Health
CPP	Condensate Polishing Plant
CPU	Central Processing Unit
CRA	Corrosion Resistant Alloys
CS	Carbon Steel
CW	Cooling Water
DAS	Distributed Acoustic Sensing
DC	Direct Current
DCC	Direct Contact Cooler
DECC	Department of Energy and Climate Change
DEM	Design Engineering Manual
DEP	Design Engineering Practice
DFP	Ductile fracture propagation
DMA	DiMethylAmine
DN	De--nitrification
DNV	Det Norske Veritas
DSC	Digital Security Controls

DSR	Desktop Safety Review
DTS	Distributed Temperature Sensors
EDDL	Electronic Device Description Language
EDP	Emergency Depressurisation
EFA	Enterprise Framework Agreement
EMR	Electricity Market Reform
EPC	Engineer, Procure and Construct
EPDM	Ethylene Propylene Rubber
ESD	Emergency Shutdown
ESDV	Emergency Shutdown Valve
E--SPIR	Electronic Spare Part Inter--changeability Record
ESS	Electrical Sub Station
ETS	Emissions Trading Scheme
EU	European Union
EU ETS	EU Emissions Trading System
F&G	Fire and Gas
FAT	Factory Acceptance Test
FBE	Fusion Bonded Epoxy
FC	Flow Controller
FDT/DTM	Field Device Tool/Device Type Manager
FEA	Finite Element Analysis
Fe_3O_4	Magnetite
FEED	Front End Engineering Design
FF	Foundation Fieldbus
FGD	Flue Gas Desulphurisation
FGS	Fire and Gas System
FTIR	Fourier transform infrared spectroscopy
FWV	Flow Wing Valve
GB	Great Britain
GI	Global Infrastructure
GPS	Global Positioning System
GRP	Glass Reinforced Plastic
GRVE	Glass Reinforced Vinyl Ester
GSS	Gland steam seal
GT	Gas Turbine
H&MB	Heat & Mass Balance
H_2	Hydrogen
H_2O	Water
H_2SO_4	Sulphuric acid
HAZOP	Hazard and Operability Study
HC	Hydrocarbon
HCF	HydroCarbon Freeing
HCl	Hydrogen chloride
HDD	Horizontal Directional Drill
HF	Hydrogen fluoride
HFC	Hydrocarbon Freeing Campaign
HFE	Human Factors Engineering
HFO	Heavy Fuel Oil
HIPPS	High Integrity Pressure Protection System

HMI	Human-Machine Interface
HNBR	Hydrogenated Nitrile Butadiene Rubber
HP	High Pressure
HPU	Hydraulic Power Unit
HRH	Hot Reheat
HRSG	Heat Recovery Steam Generator
HSE	Health & Safety Executive
HSS	Heat Stable Salts
HSSE	Health, Safety, Security and Environment
HV	High Voltage
HVAC	Heating, ventilating, and air conditioning
HVDC	High voltage direct current
IAMS	Instrument Asset Management System
IBC	Intermediate Bulk Container
ICSS	Integrated Control and Safeguarding System
IEEE	Institute of Electrical and Electronics Engineers
IP	Intelligent Pigging
IP	Intermediate Pressure
IP	Internet Protocol
IPCS	Integrated Protection and Control System
IPF	Instrumented Protective Function
IPS	Instrumented Protection System
IR	Infrared
ITT	Invitation To Tender
IX	Ion Exchange Unit
JNCC	Joint Nature Conservation Committee
JV	Joint venture
KKD	Key Knowledge Deliverable
KO	Knock Out
KOD	Knock Out Drum
LAT	Lowest Astronomical Tide
LHV	Lower Heating Value
LMTD	Log Mean Temperature Difference
LOS	Line of Sight
LP	Low Pressure
LV	Low Voltage
MAIP	Maximum Allowable Inlet Pressure
MAOP	Maximum Allowable Operating Pressure
MAT	Minimum Allowable Temperature
MBBR	Moving Biofilm Bed Reactor
MBES	Multi--Beam Echo Sounder
MBR	Moving Bed Reactor
MCC	Motor Control Centre
MEG	Monoethylene Glycol
MeOH	Methanol
MFL	Magnetic Flux Leakage
MHWN	Mean High Water Neaps
MHWS	Mean High Water Springs
MLWN	Mean Low Water Neaps

MLWS	Mean Low Water Springs
MMT	Minimum Metal Temperature
MMV	Measurement Monitoring and Verification
MP	Medium Pressure
MSL	Mean Sea Level
N_2	Nitrogen
Na_2SO_3	Sodium sulphite
Na_2SO_4	Sodium sulphate
NaCOOH	Sodium Formate
$NaNO_3$	Sodium nitrate
NaOH	Sodium hydroxide
NB	Nominal Bore
NBR	Nitrile Butadiene Rubber
NCCC	National Carbon Capture Centre
NDB	Non--Directional Beacon
NDMA	N--Nitrosodimethylamine
NFFO	National Federation of Fishermen's Organisations
NH_3	Ammonia
NO	Nitric oxide
NO_2	Nitrogen Dioxide
NOx	Nitrogen Oxides
NPSH	Net Positive Suction Head
NTS	National Transmission System
NUI	Normally Unmanned Installation
O&M	Operations and Management
O_2	Oxygen
OBN	Ocean Bottom Nodes
OCCS	Office of Carbon Capture and Storage
OD	Office Domain
OD	Outer Diameter
OEM	Original Equipment Manufacturer
OIM	Offshore Installation Manager
OIW	Oil--In--Water
OPEX	Operating Expenditure
OSBL	Outside Battery Limit
P&ID	Piping and Instrumentation Diagram
PABX	Private Automated Branch Exchange
PACO	Process Automation, Control and Optimisation
PAS	Process Automation System
PBR	Polished--Bore Receptacle
PC	Personal Computer
PCAD	Process Control Access Domain
PCC	Process Control Centre
PCCS	Peterhead Carbon Capture and Storage
PCD	Process Control Domain
PCN	Process Control Network
PCS	Process Control System
PDG	Permanent Downhole Gauge
PDMS	Plant Design Management System

PEFS	Process Engineering Flow Scheme
PFCs	Perfluorocarbons
PFD	Process Flow Diagram
PFS	Process Flow Scheme
PLC	Programmable Logic Controller
POB	Personnel On Board
PPC	Pollution, Prevention & Control
PPE	Personal Protective Equipment
ppmm	Parts per million by mass
ppmv	Parts per million by volume
ppmw	Parts per million by weight
PPS	Peterhead Power Station
PRS	Pressure reducing station
PSV	Pressure Safety Valve
PTFE	Polytetrafluoroethylene
PVC	Polyvinyl Chloride
PZV	Process Zone Valve
R&D	Research and Development
RAM	Risk Assessment Matrix
RAM	Reliability, Availability and Maintainability
ROV	Remotely Operated Vehicle
RTJ	Ring Type Joint
SCC	Stress Corrosion Cracking
SCR	Selective Catalytic Reduction
SEPA	Scottish Environment Protection Agency
SER	Sequence of Event Recording
SFF	Scottish Fisheries Federation
SGS	Safeguarding System
SIL	Safety Integrity Level
SIT	Non-flow wetted Valves
SNH	Scottish Natural Heritage
SO	Sulphur monoxide
SO_2	Sulphur dioxide
SP	Social Performance
SPA	Special Protection Area
SS	Stainless steel
SSA	Short Stay Accommodation
SSIV	Subsea Isolation Valve
SSSV	Subsurface Safety Valve
ST	Steam Turbine
SWC	Sea Water Cooling
SWS	Sea Water Supply
t/h	Tonnes per hour
TAMAP	Technically Acceptable Manufacturers and Products
TCP/IP	Transmission Control Protocol/Internet Protocol
TDR	Technical Deviation Request
TDS	Total Dissolved Solids
THP	Tubing Head Pressure
THT	Tubing Head Temperature

TKN	Total Kjeldahl
TOC	Total Organic Carbon
TRU	Thermal Reclaimer Unit
TSO	Tight Shut Off
TUTU	Topside Umbilical Termination Unit
UEFS	Utility Engineering Flow Scheme
UK	United Kingdom
UKCS	United Kingdom Continental Shelf
UMV	Upper Master gate Valve
UPS	Uninterruptable Power Supply
UT	Ultrasonic
UV	Ultra Violet
VIGV	Variable Inlet Guide Vane
VSD	Variable Speed Drive
WIT	Well Integrity Tests
WHRU	Waste Heat Recovery Unit
WWTP	Waste Water Treatment Plant
XLPE	Cross Linked Polyethylene

17. Glossary of Unit Conversions

Table 17-1: 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

APPENDIX 1. General Documents (Onshore)

Document Ref.	Document Title
PCCS-00-TC-AA-6627-00001	INTERFACE SCHEDULE
PCCS-00-TC-AA-6627-00002	INTERFACE RESPONSIBILITY SPECIFICATION
PCCS-00-TC-EA-7770-63001	ELECTRICAL STANDARD GRAPHIC SYMBOLS
PCCS-00-TC-IN-0901-00001	PAS / ESD / F&G ARCHITECTURE/ BLOCK DIAGRAM
PCCS-00-TC-MP-4024-00001	SITE MASTER PLAN (ONSHORE)
PCCS-00-TC-MP-4024-00002	OVERALL PLOT PLAN
PCCS-00-TC-PX-2365-00002-001	PIPING AND INSTRUMENTATION DIAGRAM PIPING LEGEND AND SYMBOLS
PCCS-00-TC-PX-2365-00003-001	PIPING AND INSTRUMENTATION DIAGRAM EQUIPMENT LEGEND AND SYMBOLS
PCCS-00-TC-PX-2365-00004-001	PIPING AND INSTRUMENTATION DIAGRAM EQUIPMENT TITLE LABELS
PCCS-00-TC-PX-2365-00005-001	PIPING AND INSTRUMENTATION DIAGRAM INSTRUMENTATION LEGEND AND SYMBOLS-1
PCCS-00-TC-PX-2365-00006-001	PIPING AND INSTRUMENTATION DIAGRAM INSTRUMENTATION LEGEND AND SYMBOLS-2
PCCS-00-TC-PX-2365-00007-001	PIPING AND INSTRUMENTATION DIAGRAM SAMPLE CONNECTIONS LEGENDS AND SYMBOLS
PCCS-00-TC-PX-2365-00008-001	PIPING AND INSTRUMENTATION DIAGRAM - KKS IDENTIFICATION SYSTEM
PCCS-00-TC-PX-2366-00001-001	PROCESS FLOW DIAGRAM LEGEND AND SYMBOLS

APPENDIX 2. Power Plant Documents

Document Ref.	Document Title
PCCS-01-MM-CX-4018-0001	PETERHEAD CCS A90 MAIN SITE ACCESS PROPOSED NEW LAYOUT - GENERAL ARRANGEMENT PLAN
PCCS-01-MM-CX-4018-0002	GENERAL ARRANGEMENT PLAN
PCCS-01-TC-AA-4322-00001	EQUIPMENT LIST
PCCS-01-TC-EA-2384-00001	UNIT 20 GENERATOR ONE LINE DIAGRAM
PCCS-01-TC-EA-2384-00002	UNIT 20 HV ONE LINE DIAGRAM
PCCS-01-TC-EA-2384-00003	UNIT 20 LV ONE LINE DIAGRAM
PCCS-01-TC-EA-2580-00001	UNIT 20 GENERATOR PROTECTION AND METERING DIAGRAM
PCCS-01-TC-EA-2580-00002	UNIT 20 HV PROTECTION AND METERING DIAGRAM
PCCS-01-TC-EA-2580-00003	UNIT 20 LV PROTECTION AND METERING DIAGRAM
PCCS-01-TC-EA-4329-00001	ELECTRICAL LOAD SUMMARY (POWER STATION)
PCCS-01-TC-EA-8809-00001	OVERALL EARTHING LAYOUT DRAWING (POWER STATION)
PCCS-01-TC-IN-6604-00001	ESD CAUSE AND EFFECTS PETERHEAD POWER STATION
PCCS-01-TC-PX-2365-00001-001	PROCESS / UTILITIES ENGINEERING FLOW SCHEME - AQUEOUS AMMONIA UNLOADING, STORAGE AND TRANSFER
PCCS-01-TC-PX-2365-00002-001	SUPPLY OF GASEOUS FUEL METERING, REHEATER FINAL CHANCE FILTER - GT-13
PCCS-01-TC-PX-2365-00003-001	PROCESS / UTILITIES ENGINEERING FLOW SCHEME - HEAT RECOVERY STEAM GENERATOR EXAUST GAS SYSTEM
PCCS-01-TC-PX-2365-00004-001	NEW STEAM TURBINE HP/IP/LP CASING
PCCS-01-TC-PX-2365-00005-001	PROCESS / UTILITIES ENGINEERING FLOW SCHEME - CONDENSATE AND FEED FLOW (BLOCK 2)
PCCS-01-TC-PX-2365-00006-001	PROCESS / UTILITIES ENGINEERING FLOW SCHEME - MAIN CONDENSATE SUPPLY
PCCS-01-TC-PX-2365-00007-001	PROCESS/ UTILITIES ENGINEERING FLOW SCHEME - FEEDWATER SYSTEM, FEEDWATER TANK WITH DEAERATION, HP/IP FEEDWATER SUPPLY
PCCS-01-TC-PX-2365-00008-001	PROCESS / UTILITIES ENGINEERIG FLOW SCHEME - LP MAIN STEAM/AUXILIARY STEAM SYSTEM
PCCS-01-TC-PX-2365-00009-001	REHEATING COLD REHEAT SYSTEM
PCCS-01-TC-PX-2365-00010-001	PROCESS/ UTILITIES ENGINEERING FLOW SCHEME - REHEATING HOT REHEAT SYSTEM
PCCS-01-TC-PX-2365-00011-001	PROCESS/ UTILITIES ENGINEERING FLOW SCHEME - HP MAIN STEAM
PCCS-01-TC-PX-2365-00012-001	PIPING AND INSTRUMENTATION DIAGRAM LP MAIN STEAM/AUXILIARY STEAM SYSTEM TO FEEDWATER TANK AND 20MA10
PCCS-01-TC-PX-2365-00013-001	AUXILIARY CLOSED COOLING WATER SYSTEM
PCCS-01-TC-PX-2365-00014-001	BLOCK 2 ISOLATIONS AT BLOCK 1 CONDENSER
PCCS-01-TC-PX-2365-00015-001	HRSG LP-SYSTEM HEAT RECOVERY STEAM GENERATOR LP-SYSTEM (NATURAL CIRCULATION) - BLOCK 13
PCCS-01-TC-PX-2365-00016-001	AUXILIARY CONDENSATE HEAT RECOVERY EXCHANGER AND TRIM COOLER
PCCS-01-TC-PX-2365-00017-001	FUEL OIL DAY TANK AND FUEL OIL PUMPS
PCCS-01-TC-PX-2365-00019-001	INSTRUMENT AIR DISTRIBUTION TO NEW PPS FACILITIES
PCCS-01-TC-PX-2365-00020-001	GENERAL COMPRESSED AIR DISTRIBUTION TO NEW PPS
PCCS-01-TC-PX-2365-00021-001	DEMINERALISED WATER DISTRIBUTION SYSTEM
PCCS-01-TC-PX-2365-00022-001	DEMINERALISED WATER AND RFW SYSTEM
PCCS-01-TC-PX-2365-00023-001	POTABLE WATER DISTRIBUTION SYSTEM
PCCS-01-TC-PX-2365-00024-001	TOWNS WATER RING MAIN

Document Ref.		Document Title
PCCS-01-TC-PX-2365-00025-001		MAIN AND AUXILIARY COOLING WATER SYSTEM
PCCS-01-TC-PX-2365-00026-001		PIPING AND INSTRUMENTATION DIAGRAM - AUXILIARY BOILER NO.1
PCCS-01-TC-PX-2365-00027-001		PIPING AND INSTRUMENTATION DIAGRAM - AUXILIARY BOILER CONDENSATE FLASH DRUM AND PUMPS
PCCS-01-TC-PX-2365-00028-001		PIPING AND INSTRUMENTATION DIAGRAM - AUXILIARY BOILER DEAERATOR
PCCS-01-TC-PX-2365-00029-001		PIPING AND INSTRUMENTATION DIAGRAM - AUXILIARY BFW PUMPS
PCCS-01-TC-PX-2365-00030-001		PIPING AND INSTRUMENTATION DIAGRAM - AUXILIARY BOILER BLOWDOWN DRUM
PCCS-01-TC-PX-2365-00031-001		PIPING AND INSTRUMENTATION DIAGRAM - AUXILIARY STEAM SYSTEM
PCCS-01-TC-PX-2365-00032-001		PIPING AND INSTRUMENTATION DIAGRAM - NEW GAS TURBINES GAS FEEDER LINE-PRS
PCCS-01-TC-PX-2365-00033-001		PIPING AND INSTRUMENTATION DIAGRAM - AUXILIARY BOILER FUEL GAS SKID
PCCS-01-TC-PX-2365-00034-001		STEAM GENERATOR DRAINS SYSTEM HRSG13
PCCS-01-TC-PX-2365-00035-001		INSTRUMENT AIR COMPRESSOR PACKAGE
PCCS-01-TC-PX-2365-00036-001		AIR DRYER PACKAGE
PCCS-01-TC-PX-2365-00037-001		INSTRUMENT AIR BUFFER VESSEL
PCCS-01-TC-PX-2365-00038-001		STEAM GENERATOR DRAINS SYSTEM HRSG 11, 12 & 13
PCCS-01-TC-PX-2365-00039-001		PROCESS ENGINEERING FLOW SCHEME - STEAM GENERATOR DRAINS HRSG 11 & 12 FLASH TANK
PCCS-01-TC-PX-2365-00040-001		CLEAN DRAINS SYSTEM BLOCK 1
PCCS-01-TC-PX-2365-00041-001		CLEAN DRAINS SYSTEM BLOCK 2
PCCS-01-TC-PX-2365-00042-001		CLEAN DRAINS SYSTEM STEAM TURBINE 20
PCCS-01-TC-PX-2366-00001-001		PROCESS FLOW SCHEME - AQUEOUS AMMONIA STORAGE AND TRANSFER TO SCR SYSTEM
PCCS-01-TC-PX-2366-00002-001		UTILITY FLOW SCHEME SEA WATER DISTRIBUTION SUPPLY AND RETURN
PCCS-01-TC-PX-2366-00003-001		UTILITY FLOW SCHEME CONDENSATE POLISHING AND FEED WATER TANK
PCCS-01-TC-PX-2366-00004-001		PROCESS FLOW SCHEME - GENERATION FACILITIES HRSG 13 & ST13
PCCS-01-TC-PX-2366-00005-001		ADDITIONAL GENERATION FACILITIES AND CCP UTILITY DISTRIBUTION,
PCCS-01-TC-PX-2366-00006-001		PROCESS FLOW SCHEME - NEW AUXILIARY BOILERS AND STEAM DISTRIBUTION,
PCCS-01-TC-PX-2366-00007-001		NEW POWER PLANT INSTRUMENT AIR
PCCS-01-TC-PX-2366-00008-001		PROCESS FLOW SCHEME - STEAM DRAINS COLLECTION SYSTEM
PCCS-01-TC-PX-5527-00001	Note 1	PROCESS DESCRIPTION (CCS PROJECT 'GENERATION FACILITIES')
PCCS-01-TC-PX-7180-00005		UTILITIES REQUIREMENT REPORT (GENERATION FACILITIES)
PCCS-01-TC-PX-8240-00001	Note 1	HEAT AND MATERIAL BALANCE (GENERATION FACILITIES)

Note 1. The Process Description and the Heat and Material Balance documents do not include the impact of the Gas Turbine Upgrades and they will be updated in the Detailed Design phase to reflect the amended scope.

APPENDIX 3. CCC Documents

Document Ref.		Document Title
PCCS-00-TC-HX-0505-00011		FIREWATER DEMAND REPORT
PCCS-02-TC-AA-4322-00001	Note 1	EQUIPMENT LIST - CAPTURE PLANT
PCCS-02-TC-EA-2384-00001		SUBSTATION ESS-3000 ONE LINE DIAGRAM
PCCS-02-TC-EA-2384-00002		SUBSTATION ESS-2000 ONE LINE DIAGRAM
PCCS-02-TC-EA-2384-00003		AC UPS ONE LINE DIAGRAM
PCCS-02-TC-EA-2384-00004		EMERGENCY ONE LINE DIAGRAM
PCCS-02-TC-EA-2384-00005		DC UPS ONE LINE DIAGRAM
PCCS-02-TC-EA-2580-00001		HV AND LV PROTECTION & METERING DIAGRAMS
PCCS-02-TC-EA-4329-00001	Note 1	ELECTRICAL LOAD SUMMARY (CCCC)
PCCS-02-TC-EA-8809-00001		OVERALL EARTHING LAYOUT DRAWING (CCCC)
PCCS-02-TC-IN-6604-00001		ESD CAUSE AND EFFECTS CARBON CAPTURE AND STORAGE (ONSHORE)
PCCS-02-TC-PX-2365-00001-001		PROCESS ENGINEERING FLOW SCHEME- BOOSTER FAN - FLUE GAS SYSTEM
PCCS-02-TC-PX-2365-00002-001		PROCESS ENGINEERING FLOW SCHEME- GAS-GAS HEAT EXCHANGER
PCCS-02-TC-PX-2365-00003-001		PROCESS ENGINEERING FLOW SCHEME- DIRECT CONTACT COOLER
PCCS-02-TC-PX-2365-00004-001		PROCESS ENGINEERING FLOW SCHEME- DIRECT CONTACT COOLER PUMPS
PCCS-02-TC-PX-2365-00005-001		PROCESS ENGINEERING FLOW SCHEME- DIRECT CONTACT COOLER WATER COOLERS
PCCS-02-TC-PX-2365-00037-001		PROCESS ENGINEERING FLOW SCHEME- CAUSTIC SYSTEM & DILUTION
PCCS-02-TC-PX-2365-00038-001		PROCESS ENGINEERING FLOW SCHEME- SULPHURIC ACID SYSTEM
PCCS-02-TC-PX-2365-00042-001		PROCESS ENGINEERING FLOW SCHEME CHEMICAL SEWER COLLECTION DRAWING
PCCS-02-TC-PX-2365-00043-001		PROCESS ENGINEERING FLOW SCHEME CO_2 CAPTURE CHEMICAL SEWER TANK AND PUMP
PCCS-02-TC-PX-2365-00050-001		PROCESS ENGINEERING FLOW SCHEME- 1ST COMPRESSION STAGE SUCTION KO DRUM
PCCS-02-TC-PX-2365-00051-001		PROCESS ENGINEERING FLOW SCHEME- PROCESS CONSDENSATE RETURN PUMPS
PCCS-02-TC-PX-2365-00052-001		PROCESS ENGINEERING FLOW SCHEME- COMPRESSOR PACKAGE (PART 1)
PCCS-02-TC-PX-2365-00054-001		PROCESS ENGINEERING FLOW SCHEME- OXYGEN REMOVAL REACTOR
PCCS-02-TC-PX-2365-00055-001		PROCESS ENGINEERING FLOW SCHEME- REACTOR OUTLET COOLER
PCCS-02-TC-PX-2365-00056-001		PROCESS ENGINEERING FLOW SCHEME- CO_2 DEHYDRATION FILTER COALESCER
PCCS-02-TC-PX-2365-00057-001		PROCESS ENGINEERING FLOW SCHEME- MOLECULAR SIEVE 1
PCCS-02-TC-PX-2365-00058-001		PROCESS ENGINEERING FLOW SCHEME- MOLECULAR SIEVE 2
PCCS-02-TC-PX-2365-00059-001		PROCESS ENGINEERING FLOW SCHEME- REGENERATION GAS PRE-HEATER & ELECTIC HEATER
PCCS-02-TC-PX-2365-00060-001		PROCESS ENGINEERING FLOW SCHEME- REGENERATION GAS DISCHARGE FILTER & COOLER
PCCS-02-TC-PX-2365-00061-001		PROCESS ENGINEERING FLOW SCHEME- REGENERATION GAS DISCHARGE SEPARATOR
PCCS-02-TC-PX-2365-00062-001		PROCESS ENGINEERING FLOW SCHEME- REGENERATION GAS COMPRESSOR
PCCS-02-TC-PX-2365-00063-001		PROCESS ENGINEERING FLOW SCHEME- COMPRESSOR PACKAGE (PART 2)

Document Ref.	Document Title
PCCS-02-TC-PX-2365-00064-001	PROCESS ENGINEERING FLOW SCHEME- FISCAL METERING PACKAGE AND HIPPS SYSTEM
PCCS-02-TC-PX-2365-00070-001	UTILITIES LP CONDENSATE DRUM
PCCS-02-TC-PX-2365-00071-001	UTILITIES LP CONDENSATE DRUM PUMPS
PCCS-02-TC-PX-2365-00072-001	UTILITIES LP CONDENSATE COOLERS
PCCS-02-TC-PX-2365-00073-001	UTILITIES BACK WASH FILTER
PCCS-02-TC-PX-2365-00074-001	UTILITIES CLOSED LOOP COOLER
PCCS-02-TC-PX-2365-00075-001	UTILITIES EXPANSION VESSEL & CHEMICAL DOSING PACKAGE
PCCS-02-TC-PX-2365-00076-001	UTILITY ENGINEERING FLOW SCHEME- CLOSED LOOP CIRCULATION PUMPS
PCCS-02-TC-PX-2365-00077-001.Note 1	UTILITIES EFFLUENT TREATMENT & PH CONTROL PACKAGE
PCCS-02-TC-PX-2365-00079-001	UTILITIES TOWNS WATER BREAK TANK & PUMP
PCCS-02-TC-PX-2365-00080-001	UTILITIES INSTRUMENT AIR COMPRESSOR PACKAGE
PCCS-02-TC-PX-2365-00081-001	UTILITIES INSTRUMENT AIR DRYER PACKAGE
PCCS-02-TC-PX-2365-00082-001	UTILITIES AIR BUFFER VESSEL
PCCS-02-TC-PX-2365-00087-001	UTILITY ENGINEERING FLOW SCHEME VENT KO DRUM CO_2 VAPORIZER AND VENT STACK
PCCS-02-TC-PX-2365-00101-001	LP CONDENSATE DISTRIBUTION
PCCS-02-TC-PX-2365-00103-001	UTILITIES CLOSED LOOP COOLING WATER DISTRIBUTION
PCCS-02-TC-PX-2365-00107-001	UTILITIES DEMIN WATER DISTRIBUTION
PCCS-02-TC-PX-2365-00108-001	UTILITY ENGINEERING FLOW SCHEME MP STEAM DISTRIBUTION AND CONDENSATE COLLECTION
PCCS-02-TC-PX-2365-00110-001	UTILITIES UTILITY DISTRIBUTION
PCCS-02-TC-PX-2365-00111-001	UTILITY ENGINEERING FLOW SCHEME – FIREWATER DISTRIBUTION NETWORK
PCCS-02-TC-PX-2366-00001-001	PROCESS FLOW SCHEME - FLUE GAS PRE-TREATMENT
PCCS-02-TC-PX-2366-00002-001	PROCESS FLOW SCHEME - CO_2 ABSORPTION
PCCS-02-TC-PX-2366-00003-001	PROCESS FLOW SCHEME - AMINE HANDLING
PCCS-02-TC-PX-2366-00004-001	PROCESS FLOW SCHEME - AMINE REGENERATION
PCCS-02-TC-PX-2366-00005-001	PROCESS FLOW SCHEME - ION EXCHANGE PACKAGE
PCCS-02-TC-PX-2366-00006-001	PROCESS FLOW SCHEME - CO_2 AMINE THERMAL RECLAIMER NO. 1
PCCS-02-TC-PX-2366-00007-001	PROCESS FLOW SCHEME - CO_2 AMINE THERMAL RECLAIMER NO. 2
PCCS-02-TC-PX-2366-00008-001	PROCESS FLOW SCHEME - CO_2 AMINE THERMAL RECLAIMER NO. 3
PCCS-02-TC-PX-2366-00009-001	PROCESS FLOW SCHEME - COMPRESSION & CONDITIONING-1
PCCS-02-TC-PX-2366-00010-001	PROCESS FLOW SCHEME - COMPRESSION & CONDITIONING -2
PCCS-02-TC-PX-2366-00011-001	PROCESS FLOW SCHEME - DEHYDRATION PACKAGE
PCCS-02-TC-PX-2366-00012-001	PROCESS FLOW SCHEME - AMINE DRAIN TANK
PCCS-02-TC-PX-2366-00013-001	PROCESS FLOW SCHEME - DEGRADED AMINE CO_2 VESSEL
PCCS-02-TC-PX-2366-00014-001	PROCESS FLOW SCHEME - CHEMICAL STORAGE & UNLOADING
PCCS-02-TC-PX-2366-00015-001	PROCESS FLOW SCHEME CHEMICAL SEWER TANK AND CHEMICAL SEWER PUMP
PCCS-02-TC-PX-2366-00021-001	UTILITY FLOW SCHEME - STEAM & CONDENSATE SYSTEM
PCCS-02-TC-PX-2366-00022-001	UTILITY FLOW SCHEME - SEA WATER AND COOLING WATER SYSTEM
PCCS-02-TC-PX-2366-00023-001 Note 1	UTILITY FLOW SCHEME - EFFLUENT SYSTEMS
PCCS-02-TC-PX-2366-00024-001	UTILITY FLOW SCHEME - INSTRUMENT AIR SYSTEM
PCCS-02-TC-PX-2366-00025-001	UTILITY FLOW SCHEME -DEMIN, DRINKING AND SERVICE WATER SYSTEM
PCCS-02-TC-PX-2366-00026-001	UTILITY FLOW SCHEME MP STEAM AND CONDENSATE SYSTEM
PCCS-02-TC-PX-2366-00027-001	UTILITY FLOW SCHEME - CO_2 VENT SYSTEM
PCCS-02-TC-PX-7180-00005	UTILITY REQUIREMENT REPORT / UTILITY SUMMARIES

Document Ref.		Document Title
PCCS-02-TC-PX-8240-00001	Note 1	HEAT & MATERIAL BALANCE
PCCS-02-TC-RA-2349-00002		MATERIAL SELECTION DIAGRAM: CO_2 ABSORPTION
PCCS-02-TC-RA-2349-00003		MATERIAL SELECTION DIAGRAM: AMINE HANDLING
PCCS-02-TC-RA-2349-00004		MATERIAL SELECTION DIAGRAM: AMINE REGENERATION
PCCS-02-TC-RA-2349-00005		MATERIAL SELECTION DIAGRAM: ION EXCHANGE PACKAGE
PCCS-02-TC-RA-2349-00006		MATERIAL SELECTION DIAGRAM: CO_2 AMINE THERMAL RECLAIMER NO.1
PCCS-02-TC-RA-2349-00007		MATERIAL SELECTION DIAGRAM: CO_2 AMINE THERMAL RECLAIMER NO.2
PCCS-02-TC-RA-2349-00008		MATERIAL SELECTION DIAGRAM: CO_2 AMINE THERMAL RECLAIMER NO.3

Note 1. The Equipment List, Electrical Load Summary, Utility Flow Scheme – Effluent Systems, Utilities Engineering Flow Scheme – Effluent Treatment & pH Control Package and the Heat and Material Balance documents do not do not reflect the simplified Waste Water Treatment Plant and offsite disposal of Acid Wash effluent as adopted at the end of the FEED phase. The documents will be updated in the Detailed Design phase to reflect the amended scope.

APPENDIX 4. Transport Documents

Document Ref.	Document Title
PCCS-06-SUB-LA-4018-00006-001	HDD SHORE APPROACH PLAN ROUTE AND LONGITUDINAL PROFILE
PCCS-06-SUB-LA-4018-00007-001	HDD SHORE APPROACH ONSHORE PIPELINE ROUTE
PCCS-06-SUB-LA-4018-00010-001	HDD SHORE APPROACH PLAN ROUTE GENERAL ARRANGEMENT
PCCS-06-SUB-LA-4024-00001-001	OVERALL FIELD LAYOUT
PCCS-06-SUB-PX-2365-00001-001	PROCESS ENGINEERING FLOW SCHEME SYMBOLS AND LEGEND
PCCS-06-SUB-PX-2365-00002-001	ONSHORE PIG LAUNCHER/RECEIVER PROCESS ENGINEERING FLOW SCHEME
PCCS-06-SUB-PX-2365-00003-001	SSIV PROCESS ENGINEERING FLOW SCHEME
PCCS-06-SUB-PX-2366-00007-001	OVERALL SYSTEM PROCESS FLOW SCHEME
PCCS-07-PTD-MP-4018-00001-001	MECHANICAL GENERAL ARRANGEMENT NORTH (METHANOL AT ST. FERGUS)
PCCS-07-PTD-MP-4018-00002-001	MECHANICAL GENERAL ARRANGEMENT SOUTH (METHANOL AT ST. FERGUS)
PCCS-07-PTD-MP-4363-00001	TIE-IN LIST AND SCHEDULE (METHANOL AT ST. FERGUS)
PCCS-07-PTD-PX-2365-77000-001	PEFS UNIT 7700 METHANOL STORAGE TANK T-7703 AND REDUNDANT GLYCOL TANKS T-7702, P-7707
PCCS-07-PTD-PX-2365-77000-002	PEFS REDUNDANT UNIT 7700 METHANOL & GLYCOL INJECTION PUMPS P-7704, P-7705, S-7703, V-7704A1, V-7704B1, V-7704A2, V-7704B2
PCCS-07-PTD-PX-2365-77000-003	PEFS UNIT 7700 METHANOL SUMP V-7704, P-7706, P-7708
PCCS-07-PTD-PX-2366-77001-001	UFS METHENOL INJECTION SYSTEM (ST. FERGUS)
PCCS-07-PTD-PX-6612-00001-001	PCCS ST FERGUS METHANOL SUPPLY EQUIPMENT LIST

APPENDIX 5. Storage Documents

Document Ref.	Document Title
PCCS-04-PTD-MP-4018-00001-001	MECHANICAL GA DRAWING CELLAR DECK
PCCS-04-PTD-MP-4018-00002-001	MECHANICAL GA DRAWING CELLAR DECK
PCCS-04-PTD-MP-4018-00003-001	MECHANICAL GA DRAWING MEZZ DECK
PCCS-04-PTD-MP-4018-00004-001	MECHANICAL GA DRAWING WEATHER DECK
PCCS-04-PTD-MP-4018-00005-001	PLOT PLAN CELLAR DECK EL +22000
PCCS-04-PTD-MP-4018-00006-001	PLOT PLAN MEZZ DECK EL +27150
PCCS-04-PTD-MP-4018-00007-001	PLOT PLAN WEATHER DECK EL +31500
PCCS-04-PTD-PX-2365-00000-001	ZG LEGEND SHEET 1
PCCS-04-PTD-PX-2365-00000-002	ZG LEGEND SHEET 2
PCCS-04-PTD-PX-2365-00000-003	ZG LEGEND SHEET 3
PCCS-04-PTD-PX-2365-00000-004	ZG LEGEND SHEET 4
PCCS-04-PTD-PX-2365-00000-005	ZG LEGEND SHEET 5
PCCS-04-PTD-PX-2365-01000-001	PROCESS ENGINEERING FLOW SCHEME CO_2 INJECTION MANIFOLD
PCCS-04-PTD-PX-2365-10000-001	PROCESS ENGINEERING FLOW SCHEME ZG TYPICAL CO_2 INJECTION WELLHEAD
PCCS-04-PTD-PX-2365-10000-002	PROCESS ENGINEERING FLOW SCHEME MONITORING WELLHEAD
PCCS-04-PTD-PX-2365-10000-003	UTILITY ENGINEERING FLOW SCHEME ZG HYDRAULIC POWER STATION
PCCS-04-PTD-PX-2365-20000-001	PROCESS ENGINEERING FLOW SCHEME ZG CO_2 IMPORT SYSTEM AND PIG RECEIVER
PCCS-04-PTD-PX-2365-20000-002	PROCESS ENGINEERING FLOW SCHEME CO_2 FILTERS
PCCS-04-PTD-PX-2365-50000-001	PROCESS ENGINEERING FLOW SCHEME WELL BLEED OFF MANIFOLD ARRANGEMENT
PCCS-04-PTD-PX-2365-50000-002	PROCESS ENGINEERING FLOW SCHEME ZG VENT KNOCKOUT DRUM V-50003, P-50003, A-50002
PCCS-04-PTD-PX-2365-59000-001	UTILITY ENGINEERING FLOW SCHEME ZG NITROGEN SYSTEM
PCCS-04-PTD-PX-2365-61000-001	UTILITY ENGINEERING FLOW SCHEME ZG DRAINS SYSTEM T-60010
PCCS-04-PTD-PX-2365-73000-001	UTILITY ENGINEERING FLOW SCHEME ZG CHEMICAL INJECTION SYSTEM FOR CCS PROJECT
PCCS-04-PTD-PX-2366-00001-001	PFS (*OFFSHORE PROCESS FLOW SCHEME GOLDENEYE FLOWS COMPOSITIONS AND OPERATING CONDITIONS*)
PCCS-04-PTD-PX-2366-01001-001	OFFSHORE PROCESS FLOW SCHEME SHELL GOLDENEYE TOPSIDES FACILITIES FOR CARBON STORAGE
PCCS-04-PTD-PX-2366-40001-001	OFFSHORE PROCESS FLOW SCHEME GOLDENEYE STORAGE GENERAL UTILITIES FOR CARBON STORAGE
PCCS-04-PTD-PX-2366-50001-001	OFFSHORE UTILITY FLOW SCHEME GOLDENEYE CO_2 VENTING SYSTEMS
PCCS-04-PTD-PX-2366-50002-001	UTILITY FLOW SCHEME GOLDENEYE WELLHEAD & LUBRICATOR VENT SYSTEM
PCCS-04-PTD-PX-6612-00001-001	GOLDENEYE PLATFORM MASTER EQUIPMENT LIST FOR PCCS
PCCS-04-PT-PX-2366-01001-001	PROCESS FLOW SCHEME, GOLDENEYE TOPSIDES FACILITIES FOR CARBON STORAGE