Peterhead CCS Project

Doc Title: - Well Functional Specification (WFS) Document

Doc No. PCCS-05-PT-ZW-7180-00005
Date of issue: 12/09/2014
Revision: K02
DECC Ref No: 11.098
Knowledge Cat: KKD-Subsurface

KEYWORDS
Goldeneye, CO_2, Well Functional Specification, WFS, Completion, Materials, Casing, Tubing, Components.

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

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Executive Summary

The objective is to determine the Well Functional Specification (WFS) for the wells in the Peterhead Goldeneye Carbon, Capture and Storage (CCS) project. It documents the requirements of the well, what the well should target and its behaviour over the lifecycle of the project.

This document is a natural evolution of the Longannet Goldeneye CCS Key Knowledge Deliverable report (UKCCS-KT-S7.16-Shell-005: Well Functional Specification, 2011) considering the new conditions of the Peterhead Goldeneye CCS project (flow rates, pressure and CO_2 composition).

The Well Technical Specification (WTS) will be produced at the end of FEED. The WTS documents how the wells will work and how it is going to be built. The WTS identifies the technical requirements required to deliver the wells completion in accordance with the WFS.

This document considers the workover of the existing wells. For CCS purpose, the Goldeneye wells specification changes from hydrocarbon production to CO_2 injection. It is therefore necessary to ensure that the wells can accommodate the new conditions, requiring workover in order to make the necessary adjustments.

1. Introduction

This report provides a statement of requirements for Goldeneye platform wells under CO_2 injection, which includes:

- Existing well conditions
- General Peterhead – Goldeneye CCS information (formation and fluid characteristics, fluid composition)
- General Completion Requirements
- Hydraulic conditions (CO_2 injection rates and conditions, pressure and temperature calculation)
- Well components
- Well management: well intervention, monitoring, operations, remedial activities and future abandonment.
- Number of wells
- Initial well modifications

Each of the specifications in turn generates further requirements, which are discussed and specified. Examples include the injection rate envelope. This dictates tubing sizes for the life of the well.

Transient conditions (well starting-up and closing-in operations) induce low temperatures near the top of the well which have been considered in terms of well integrity under injection conditions.

The Figure 1-1 summarises the required changes to the existing wells for conversion to CCS and the aspects that still needs attention during the define phase of the project (FEED).

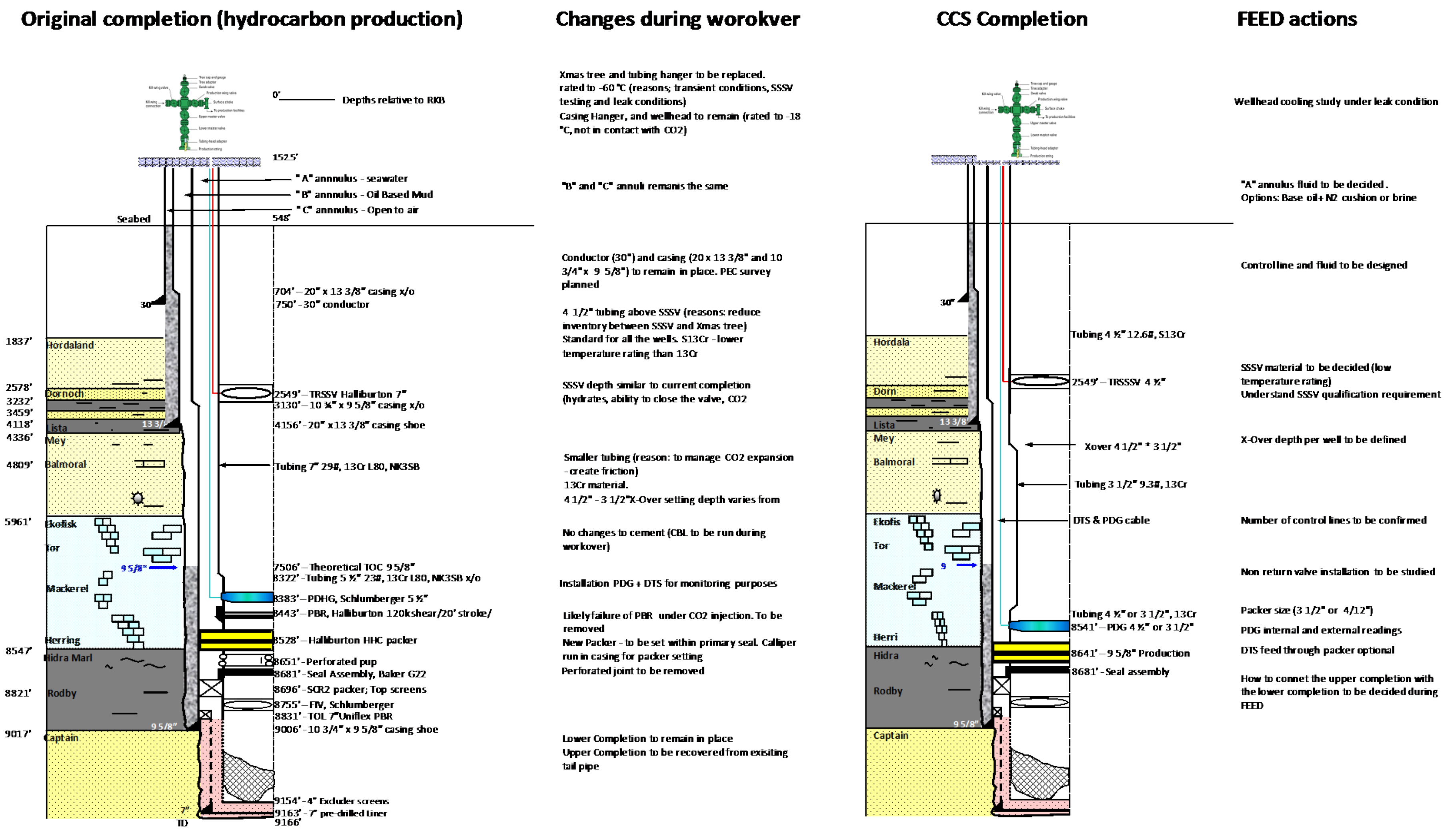


Figure 1-1: Summary of changes required during workover for CCS operation

2. Existing Well Conditions

The Goldeneye platform features five suspended gas production wells, with an additional three spare slots for potential future wells.

The five existing wells in the Goldeneye platform initially drilled and completed to produce hydrocarbons from the Captain sands, Table 2-1 . The abbreviated well names are used in this document. Well DTI 14/29a-A4Z (GYA02S1) is the sidetrack of DTI 14/29a-A4 (GYA02).

Table 2-1 Existing hydrocarbon producer wells in Goldeneye platform

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	5/12/2003
DTI 14/29a-A2	GYA05	2/12/2003

The field was granted CoP (Cessation of Production) from DECC (Department of Energy and Climate Change) in 2011. There are therefore no plans to produce the wells in the future.

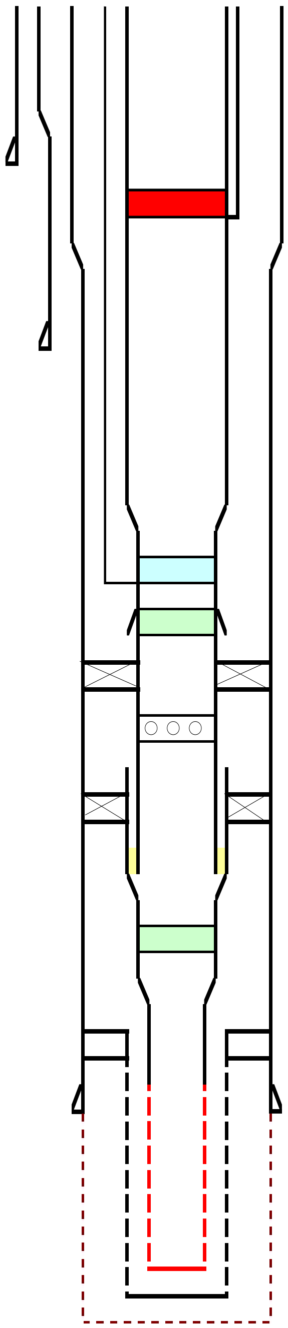
2.1.1. Wells Construction Summary

The existing wells construction summary is presented below, Table 2-2:

Table 2-2: General well construction characteristics

On/Offshore	Offshore
Well type	Previously Hydrocarbon producer. Currently closed in and suspended with deep set downhole plugs To be converted to CO_2 injection
Drill Floor Elevation (DFE) (ft)	152.5 [46.5m] (Drilling Rig)
Water depth (ft)	395 [120m]
Number of wells	5 existing, 3 slots available
Top reservoir (ft TVDSS)	~8300 [2530m]

Below, Figure 2-1, is a simplified schematic of one of the existing well (GYA01).



	GYA01 AHD	TVD
20 x 13 3/8" X-Over	704	704
30" Conductor	750	749.75
TRSSSV	2549	2525
10 3/4" x 9 5/8" Casing X-Over	3130	3090
13 3/8" Shoe	4156	4076
7 x 5 1/2" Tubing X-Over	8322	7805
Gauge Mandrel	8383	7859
PBR (Not sheared)	8443	7911
9 5/8" Halliburton Packer	8528	7986
Perforated Pup Joint	8651	8094
9 5/8" Baker Seal Assembly	8681	8121
9 5/8" Baker Packer	8696	8134
5" Baker Ratcheting Mule	8705	8142
7" x 5 " X-Over	8744	8176
FIV	8755	8186
5" x 4" X-Over	8785	8212
Liner Hanger	8831	8253
4" Baker screens	8952	
9 5/8" casing shore	9006	8408
7" Predrilled liner		
Baker Screens Bull Nose	9154	8539
Pre-drilled liner Shoe	9163	8547
TD	9166	8550

Figure 2-1: GYA01. Summary of existing completion schematic

The upper and lower completion specifications of the current completion are:

- Upper Completion

SSSV 5.875" [149.2mm], 7" [178mm] tubing 6.184" [157mm], 5" [127mm] tubing 4.67" [118.6mm], PDG 4.576" [116.23mm], Polished Bore Receptacle (PBR) 4.577" [116.26], Packer 4.65" [118.1mm]

- Lower Completion

Formation Isolation Valve (FIV) 2.94" [74.7mm], Screens 3.548" [90.1], X-over 3.515" [89.3].

The maximum well deviation in the wells is (deg):

Table 2-3: Well deviation of the existing wells

GYA-01	36
GYA-02S1	60
GYA-03	40
GYA-04	68
GYA-05	7 (shortest well)

The Figure 2-2 and Figure 2-3 capture the existing well construction elements with respect to the different formations (the wells are similar with the difference that the packer is set at different formations. GYA02S1 is the sidetrack of GYA02):

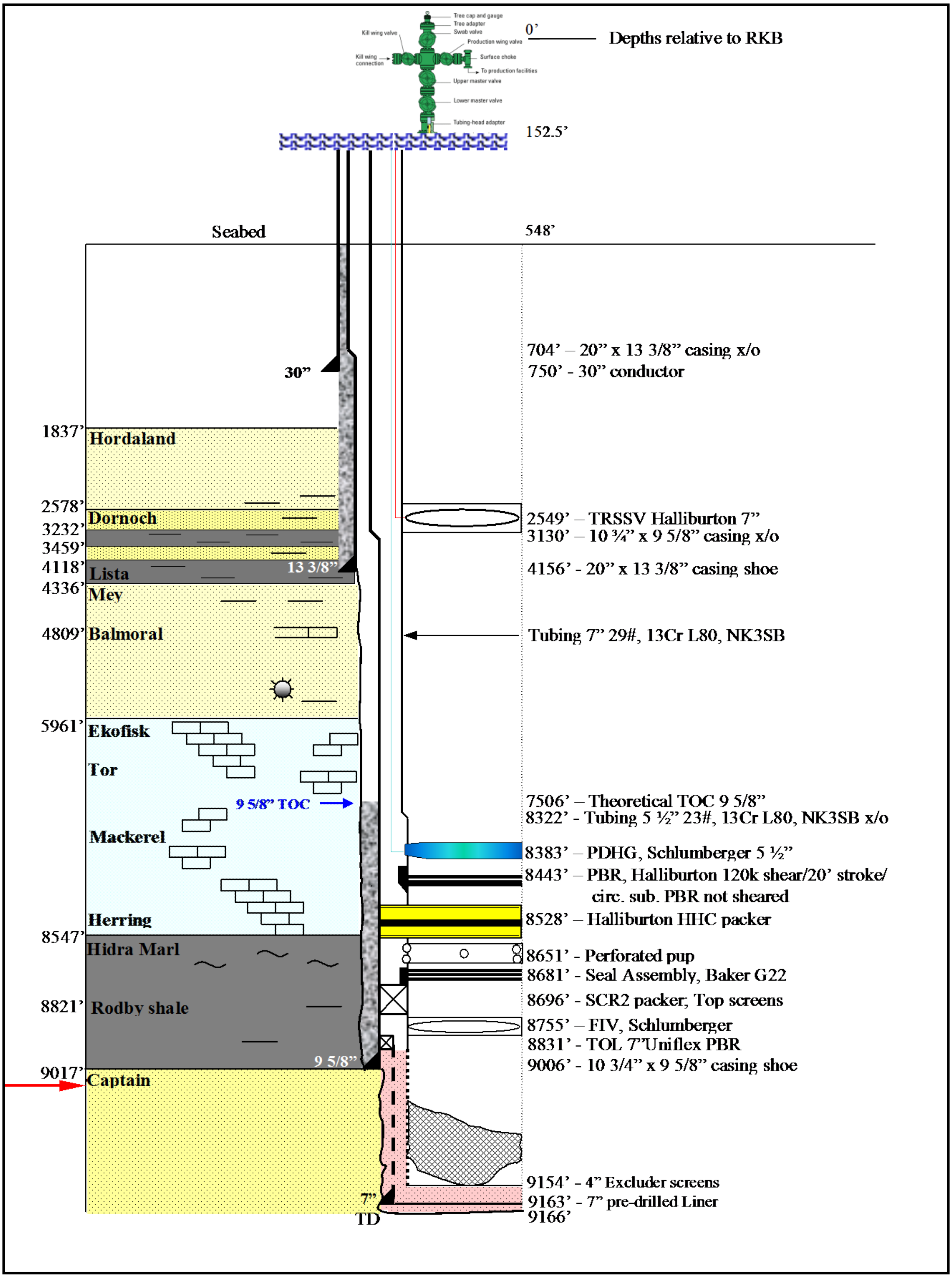


Figure 2-2: GYA01 well schematic including formations (similar completion in GYA05)

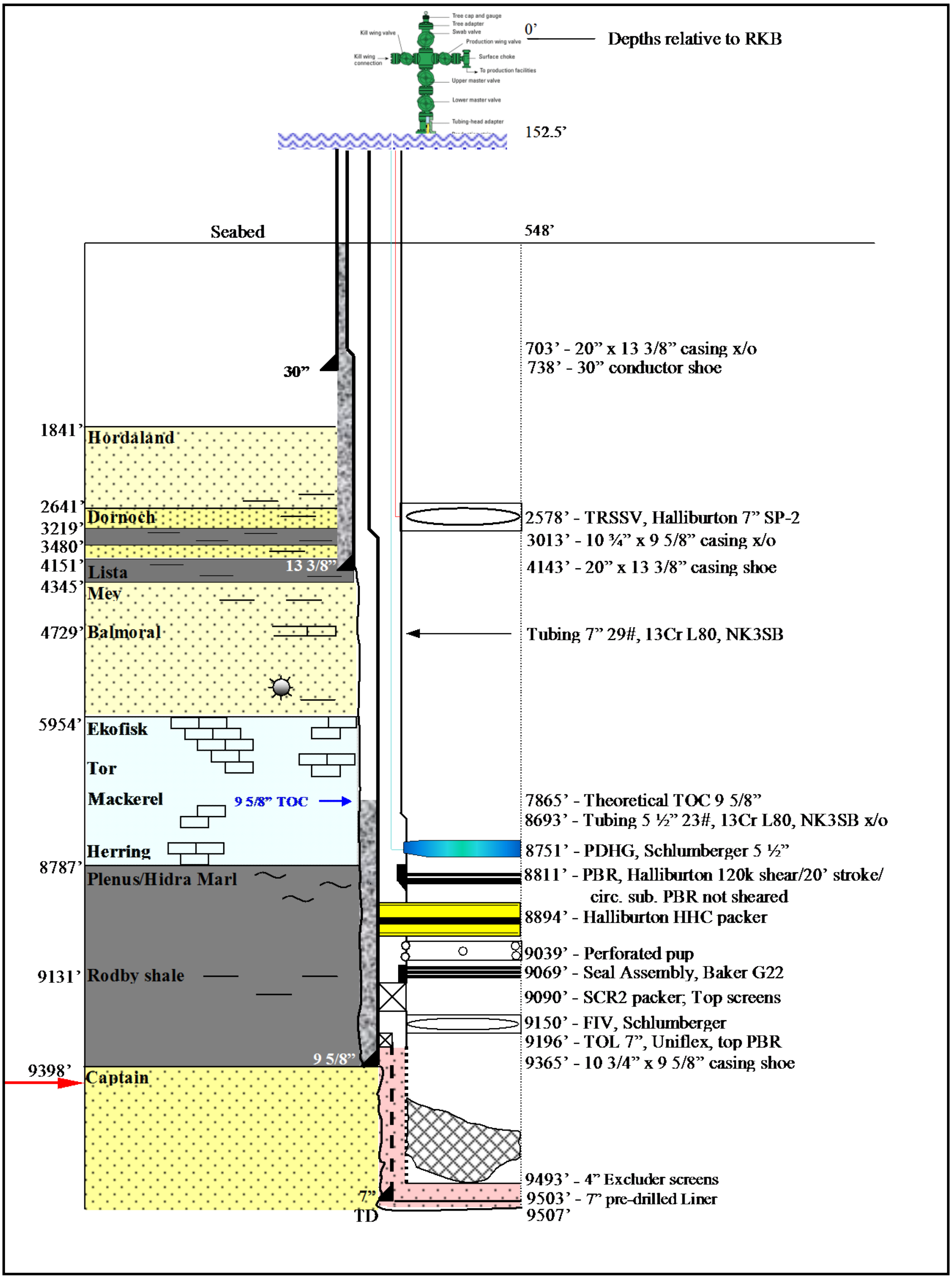


Figure 2-3: GYA03 Completion including completion (similar completion in GYA02S1 and GYA04)

2.1.2. Existing wells status

An intervention campaign was carried out in 2012 and suspension plugs were set in all the wells.

In a number of wells (GYA02, GYA04 and GYA05) the lowermost suspension plug was set above the downhole gauge thereby allowing the reservoir pressure and temperature to be monitored, Table 2-4.

Table 2-4: Suspension plugs – Setting depths

	GYA01	GYA02S1	GYA03	GYA04	GYA05
Suspended	Nov 2012	May 2012	April 2012	May 2012	Feb 2013
Plug 01	139ft [42.4m]	124ft [37.8m]	134ft [40.8m]	118ft [36m]	148ft [45m]
Plug 02	2669ft [813.5m]	10362ft [3158.3m]	2618ft [798m]	2976ft [907m]	7731ft [2356m]
Plug 03	8595ft [2619.8m]		9017ft [2748.3m]		

None of the wells are subject to major integrity issues (PCCS-05-PT-ZW-7180-00004 Well Integrity Assessment Report, 2014).

The Goldeneye wells were gravel packed for the 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 or sand failure had not taken place.

3. Peterhead – Goldeneye CCS Information

The following information will affect the completion type in the CO_2 injector wells.

3.1. General Information

Table 3-1: Goldeneye. General Information

Name	Goldeneye
Area	North Sea
Located	100km northeast of St Fergus
Basin	South Halibut Basin of the Outer Moray Firth
Platform	Normally Unattended Installation (NUI)
Legs	4
Pipeline to shore	102km, 20in [508mm] diameter
Reservoir	Lower cretaceous Captain sandstone Captain E, D (main) and C (not penetrated by the existing wells)

3.2. Goldeneye field - Geology

The injection reservoir is the Captain formation. The Rodby shales and Hidra marl are the main shales above the injection reservoir.

Vertical containment is provided by the 300m thick primary storage seal, a package including part of the Upper Valhall Formation, Rødby Formation, Hidra Formation and the Plenus Marl Bed.

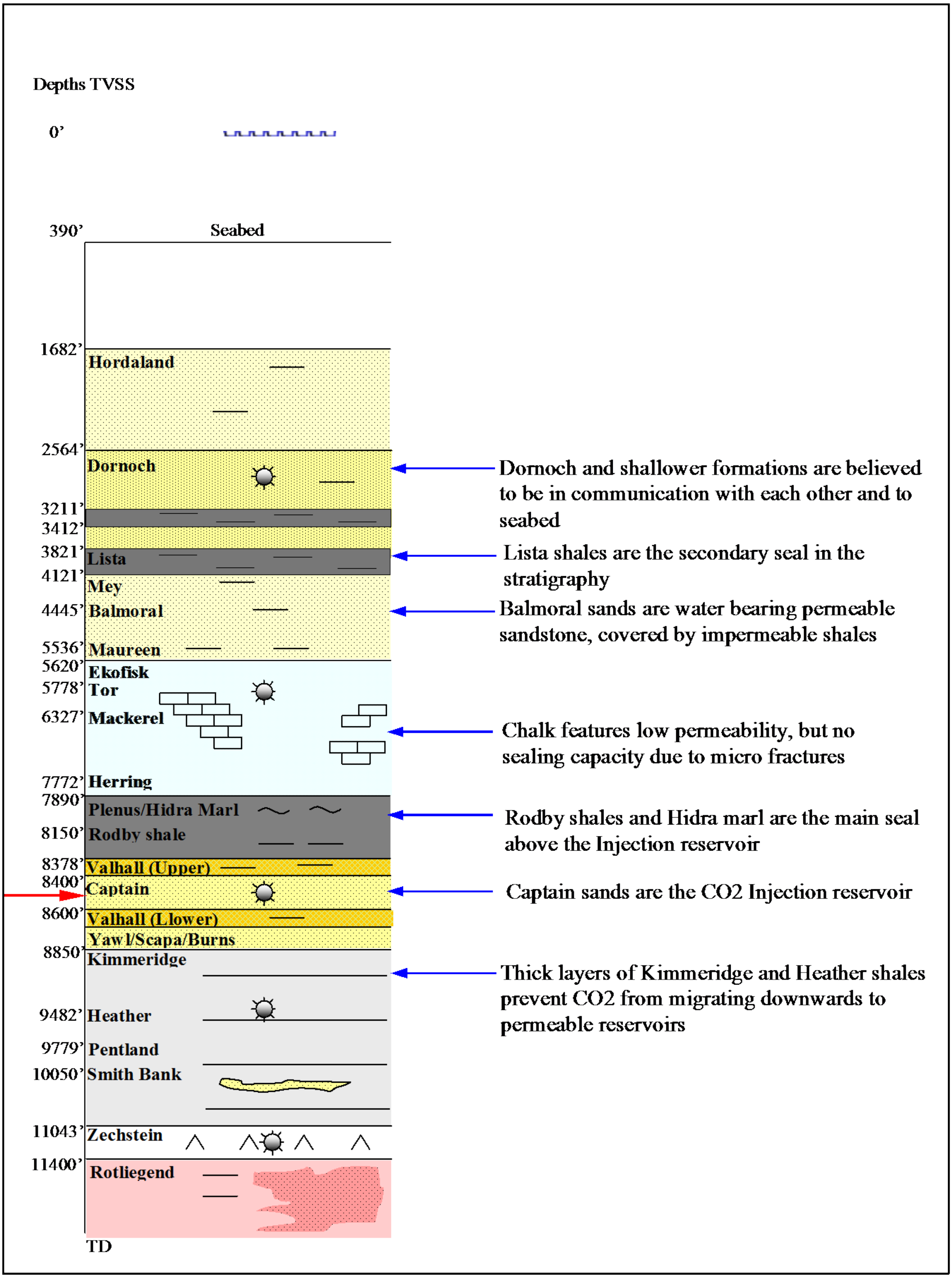


Figure 3-1: Main Stratigraphy for Goldeneye area, average depths of formation tops

3.3. Reservoir Characteristics

Table 3-2: Reservoir Characteristics

Type	Sandstone Captain formation
Formation temperature	~83°C @ 8400ft [2560m] TVDss Lower temperature to be encountered on injection (section 5.2)
Formation Water	Present in the bottom of the well.
	Water will be initially at the sand face. Evidence of water from downhole pressure gauges in GYA03.
	Formation water around the wellbore will reduce significantly after 6 to 9 months of continuous CO_2 injection. However, water might come back to the formation if not enough CO_2 is injected in the well.
Average Reservoir (Captain D) Porosity and Permeability	~25% porosity 790mD permeability The Captain D is a clean sandstone with very high Net to Gross ratio. Captain D presented an excellent connectivity during the hydrocarbon production phase.
Pressure Regime	(The pressure regime is given as an indication for general well/completion design selection. It will be re-calculated before any well operation and before working over the wells). An active aquifer supports the field. All the wells are currently shut in due to water breakthrough and isolated with deep and shallow downhole plugs.
	• Original Reservoir Pressure ~ 3830psi @datum 8400ft TVDss [264bar @datum 2560m] • Minimum Reservoir pressure after depletion ~ 2100psi @ datum [115bar @datum] • Current pressure is ~2620psi (@ end of December 2013) @ datum [181bar @datum]
	• Minimum expected reservoir pressure before CO_2 injection (~Year 2019): 2650psi [183bar], Pressure Gradient Range - 0.319 psia/ft [72.16mbar/m]
	• Maximum expected reservoir pressure after 10 million tonne of CO_2– (~Year 2031) 3450psi [238bar], Pressure Gradient: 0.416psi/ft [94.1mbar/m] Information is of enough quality for this analysis/report on WFS. This pressure information will be updated during FEED for the detail design of the wells. Different section of tubing (4 ½” and 3 ½” [114mm and 89mm]) to be installed in each well will depend on this information.

3.4. Fluids Characteristics

Table 3-3: Fluids characteristics

<table>
<tr><td>CO_2</td><td>Almost pure dehydrated CO_2 will be available at the platform level. CO_2 specification as follows:
<table>
<tr><th>Compound</th><th>% Fraction mol</th></tr>
<tr><td>CO_2</td><td>0.999883</td></tr>
<tr><td>N_2</td><td>0.000061</td></tr>
<tr><td>O_2</td><td>0.000001</td></tr>
<tr><td>H_2O</td><td>0.000050</td></tr>
<tr><td>H_2</td><td>0.000005</td></tr>
</table>

O_2 level specification is determined by the presence of 13Cr material in the wells (lower completion).
Water is controlled to avoid hydrates and corrosion in the offshore pipeline (50 ppm mol of water = 20 ppm weight of water).</td></tr>
<tr><td>Formation Water</td><td>Prior to injection, water will be initially at the sand face. Water breakthrough observed in all wells during the production phase. Evidence of water from downhole pressure gauges in GYA03.
Salinity- Total Dissolved Solids (TDS): ~56000ppm (52000ppm – Sodium Chloride - NaCl)
Water level in the wells is currently not known.
There is expected to be more water in the wells at the workover time due to aquifer presence.</td></tr>
<tr><td>Hydrocarbon</td><td>Gas – Condensate
0.37% mol CO_2
0% H_2S
No solids production observed in the facilities
There was a thin (7m) oil rim in the reservoir at original conditions.</td></tr>
</table>

4. General Considerations

The main functional requirements for the wells in the Peterhead Goldeneye CCS project are:

Hydraulic Requirements

- Management of the CO_2 properties (Joule Thomson, JT expansion) and the resultant temperatures in the existing platform wells.
- Flexible injection. The injector wells need to be able to cope with a range of CO_2 arrival rates within the limits of the capture plant and surface equipment. Facilities and their modus operandi should be operated to have minimum impact in the wells.
- CO_2 will be injected in a single phase with wellhead pressure kept above the saturation line.

Well Integrity

- Avoid any leak path through the well.
- All well completion materials should be compatible with the injected fluid and expected pressures and temperatures.
- Completion design should consider the presence of CO_2, water and hydrocarbon. The proportion will change depending on the well position and during the life of the project.
- Expected remaining well life (after start of injection: minimum 15 years).

Well Modifications

- Deep-water jack-up rig is required for Goldeneye platform due to the water depth.
- Minimise complexity and cost of any well work. Uncomplicated well design.
- No planned workover after injection.

Operational aspects

- Normally current unattended platform.
- Maintain injectivity during the life cycle of the well.
- Optimise life cycle well cost.

Well Monitoring

- Able to monitor wells/reservoir. Facilitate intervention.
- In-well monitoring to be installed in the wells: Permanent Downhole Gauges (PDG) and Distributed Temperature Sensing (DTS) (Distributed Acoustic Sensing (DAS) being considered).

Life Cycle Cost

- Regulatory requirements for the five existing Goldeneye wells will transfer from the production licence to the storage licence for the Peterhead CCS Project. As such, the costs associated with all the wells should be considered by the project (e.g. abandonment costs should be included in the cost estimates in case of selecting the options of drilling new wells).
- Reduce (or eliminate) the requirement to bring a rig in the middle of the project.
- Facilitate final well abandonment.

5. Hydraulic Requirements

5.1. CO_2 Injection Rates

Table 5-1: CO_2 Injection Rates

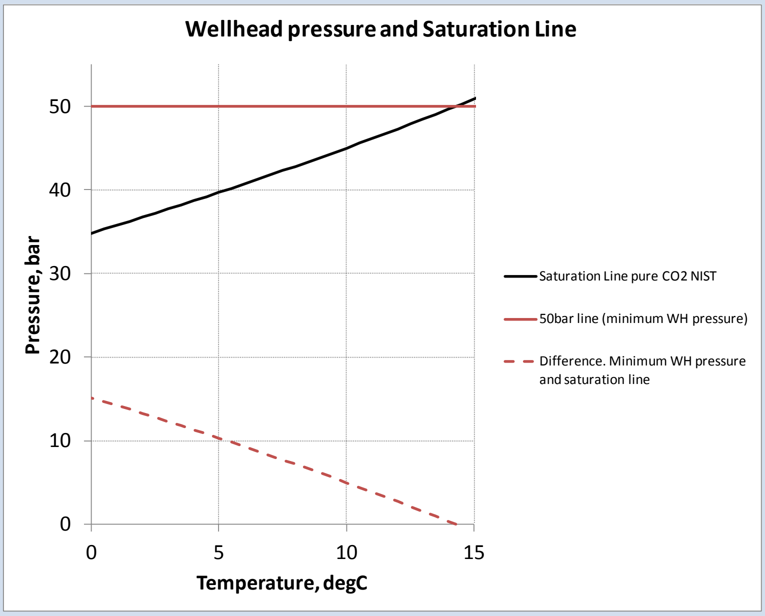
Total CO_2 available	The project requires to inject 10 million tonnes of CO_2 Design Rate (capacity of the capture plant): 138.3 tonnes/h equivalent to 63 MMscfd Normal Operating Conditions ~ 130 tonnes/h (59 MMscfd) Turndown Rate of surface facilities ~ 89.9 tonnes/h (65% of the design case, 41 MMscfd) It is estimated that the injection will take place over a period of 10 to 13 years for the 10 million tonnes (including downtime).
CO_2 fluctuation	For the first 5 years of the injection, project will operate with turndown case of 75% (103.8 tonnes/h, 47 MMscfd) For the rest of the injection years, the turndown case will be 65%. All the surface equipment should be design to minimum turndown of 65%. The reference case is to operate the capture plant at based load (i.e. continuous flow) during the first five years on injection. Daily fluctuations between the design rate and the minimum (65% of the design rate) might be carried out after year 5 of injection. Frequent (daily) on and off periods of the capture plant are not planned. A limited packing capacity exists in the offshore pipeline operated in dense phase CO_2 (estimated to be between 2 to 4 hours of CO_2 injection depending on the conditions of the pipeline).

5.2. Pressure and Temperature Conditions

5.2.1. Steady State Injection – Hydraulic Requirements

The reference case of the workover is to manage the potentially extremely low temperatures for CO_2 expansion during injection is by keeping the CO_2 stream in liquid phase at the wellhead, by increasing the required injection wellhead pressure above the saturation line. This can be achieved by extra pressure drop in the well by use of small diameter tubing creating back pressure by friction pressure loss.

Table 5-2: Steady State Injection characteristics

<table>
<tr><td>Wellhead pressure (WHP)</td><td>
Minimum: 50bar
It can be optimised considering the arrival temperature of the CO_2 to the platform.
CO_2 will be injected in a single phase with wellhead pressures kept above the saturation line.


Maximum: 120bar
This is the maximum arrival pressure to the platform limited by the offshore pipeline
</td></tr>
<tr><td>Manifold CO_2 temperature (MFT)</td><td>
CO_2 arrival temperature will present some minor seasonal variations throughout the year. This will be similar to the seabed temperature with some variations due to CO_2 riser expansion
For design purposes – the minimum temperature is estimated at 2.3°C, the maximum is 10.1°C
For operational purposes the expected fluctuation is between 5.3°C to 8°C
</td></tr>
<tr><td>Flowing Wellhead CO_2 temperature (FWHT)</td><td>There will be some JT effect across the choke being more pronounced at lower wellhead injection pressure</td></tr>
</table>

	The minimum temperature is 0.5°C at 50bar injection pressure The maximum temperature is 10.1°C at 120bar injection pressure
Bottom Hole temperature (BHT)	The bottomhole temperature (BHT) will depend on the injected fluid temperature and the rate of injection. There will be reduction of temperature around the injectors due to cold CO_2 injection. For the CCP rates in the Peterhead project, the expected BHT is between 23°C to 35 °C. Reference Case 23°C bottom hole injection temperature

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

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

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

In summary, the expected transient conditions are as follows:

Table 5-3: Results of transient calculations – design case (base oil in annulus)

	Design Case	Operating case
Steady State CO_2 MFT, °C	3	-
Steady State MFP, bara	120.2	-
Reservoir Pressure, psia	2500 [175.8Kg/cm]	2500 [175.8Kg/cm]
Steady State Conditions		
FWHP, bara	45	115
FWHT, °C	1	4
BHT, °C	17	20
Transient conditions		
Close in operation, h	2	0.5
Start Up operation, h	2	1
Coldest temperature (wellhead)		
Fluid CO_2, °C	-20	-17
Average tubing, °C	-15	-10
A annulus, °C	-11	-4
Production casing, °C	-10	-1

Strict operational procedures need to be implemented and adopted by the Goldeneye Well Operations Group to keep well components within their design temperature limitations.

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

5.2.3. SSSV testing

The valve is normally tested by initially closing the well at the Xmas tree, then closing the SSSV and bleeding off the pressure to a given value through the Christmas tree using a venting system. The pressure in the wellhead is then monitored.

Bleeding off the WH pressure for SSSV testing should be done in a controlled manner. The report (UKCCS-KT-S7.18-Shell-005: Operations Support, 2011) highlights a methodology to test the SSSV.

The current view is that the WH pressure can be reduced quickly to 27bar and then it needs to be maintained at 27bar for approximately 24-hours to allow the boiling-off of the CO_2 in the tubing or the reduction of depth of the gas interface to the SSSV. There will be a continuous CO_2 mass rate coming out of the well. Once only gas is between the wellhead and the SSSV then the pressure can be bled off rapidly to 10 Bara.

In summary, the testing of the valve should be carried out very slowly allowing for the normal boiling of the CO_2 liquid into gas to minimize the lowest temperature which can be observed in the interface gas-liquid CO_2.

It is proposed to achieve required blowdown for SSSV testing using a dedicated facility that will re-use the existing vent system. The blowdown will be performed under automatic control to minimise low temperatures and liquid produced from the well.

The implication on the well design of the SSSV testing is to install in the top of the well (above the SSSV) a material rated to lower temperatures including the Xmas tree and tubing hanger.

5.2.4. Loss of control in CO_2 wells

Under certain extreme circumstances, it is possible that a partial loss of control (e.g. a small wellhead leak) might develop. Under this scenario, a surface leak (to atmospheric conditions) will expel cold CO_2. A metal design temperature of -55°C is proposed to be used.

The influence of the low temperature into the different well elements will be variable depending on the leak rate, involved volume, time and the heat transfer from the surroundings of the well and internal elements of the well. One important factor is the ability of the SSSV to limit the amount of CO_2 to be released. This will be investigated during FEED.

Currently it is envisaged that the new Xmas tree and the tubing between the Xmas tree and the SSSV are rated to -60 °C. During FEED, a study will be carried out to validate the wellhead system and casing hanger (rated to -18 °C).

A non-return valve might be installed deep in the tubing to prevent further direct communication between the reservoir and the top of the well in case of SSSV failure. This will be investigated during FEED.

In a CO_2 well; with the rapid expansion of the CO_2, correspondingly rapid cooling will occur under a total loss of well control. Cooling can reach the point where solid dry ice particles form in the jet stream. After the loss of well control, the fluid accelerates until the pressure drop in the well matches the pressure drop between the reservoir and the pressure at the wellhead, limited by the sonic velocity. Emergency Response Plans will be developed during FEED for a loss of well control case.

5.2.5. Closed In Tubing Head Pressure (CITHP)

The CITHP will depend on the reservoir pressure (or downhole pressure) and the fluid inside the tubing. Two extreme cases exist: CO_2 filling the well or hydrocarbon gas in the tubing.

The wells will be designed to accommodate water/CO_2/gas for corrosion purposes and wellhead pressures related to hydrocarbon gas filling the tubing. For a CO_2 filled well, the CITHP is relatively low at approximately 50bar at reservoir pressures at the end of the 10 million tonnes injection of 3500psi [241bar]. See Figure 5-1 below.

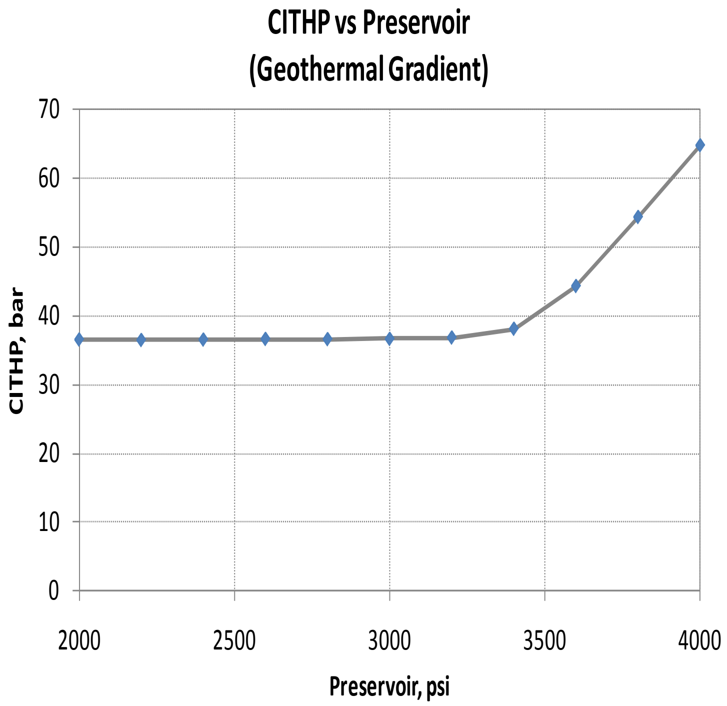
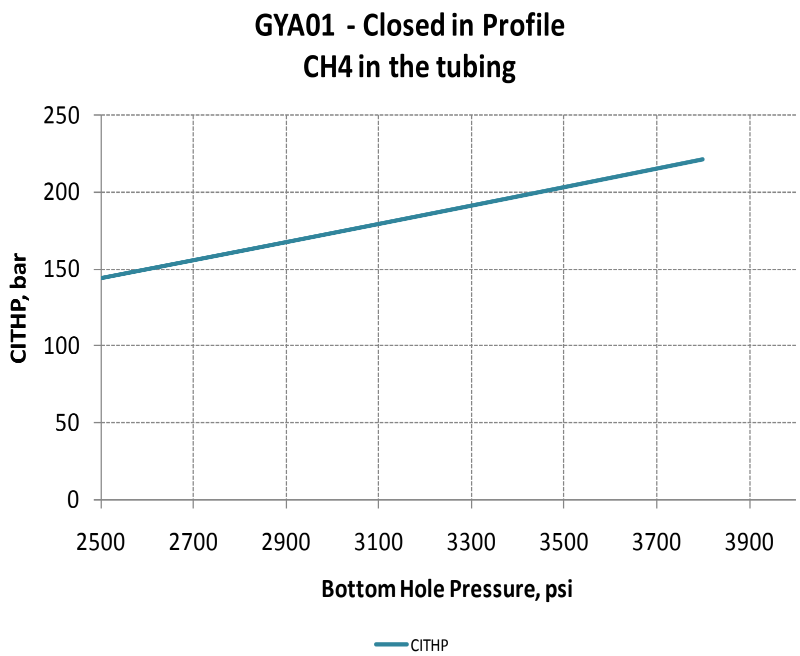


Figure 5-1: CITHP for a well filled with CO_2

In case that the well is full of hydrocarbon gas then the CITHP at the same 3500psi reservoir



pressure would be in the order of 205bar (assuming methane filling the tubing - worst case), see Figure 5-2 below.

Figure 5-2: CITHP for a well with Methane in the tubing

5.2.6. Maximum velocity

A maximum velocity in the tubing of 12m/s will be used in restricting the wells envelope. The 12 m/s maximum velocity is equivalent to having the following injection rates in different tubing sizes.

Table 5-4: Injection rates vs. tubing size

Tubing Size, in	Internal Diameter, in	In-situ Injection Rate for 12m/s in the tubing, m^3/d	Injection Rate for 12m/s in the tubing, MMscfd (CO_2 ~ 970m m^3/d)
4 ½”	3.958	8230	120
3 ½”	2.922	4700	68
2 7/8”	2.441	3130	45

6. Well Components

Limitations of the different well components were investigated for the expected well conditions under CO_2 injection. All completion equipment (i.e. attached to the tubing string) will have 13Cr or S13Cr equivalent metallurgy and will have working pressures in excess of the expected final well pressures.

Avoiding any leak path through the well is a major consideration. Integration of proper well completion design with operational aspects will limit the probability of CO_2 leaks. Based on corrosion analysis, well completion design will consider long-term durability of well completion equipment. Seal sections and stagnant zones in the well completion are critical.

6.1. Workover Requirement

The five existing wells were evaluated for use with CO_2 injection without any modification, (PCCS-05-PT-ZW-7180-00003 Well Completion Concept Select Report, 2014).

- There is a risk of unlatching the polished-bore receptacle (PBR), due to cooling of the tubing string, on the current completion that could create a well integrity issue by creating a leak path between the tubing and “A”-annulus.
- 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. Otherwise, some well components in the top will be out of the equipment rating

Changing to CO_2 injection will require a workover to install a single tapered tubing string in order to manage the CO_2 phase behaviour and to keep the integrity of the well. A mobile jack-up rig is required to carry out a workover of the upper completion.

The upper completion (down to the tail pipe) will be changed and the lower completion (up to the screen hanger) will remain in place.

6.2. Material/Corrosion

Table 6-1: Material and Corrosion aspects

Carbon Steel	CO_2 in the presence of water will lead to dissolution of CO_2, forming carbonic acid (H_2CO_3). This will lead to corrosion of carbon steel. The typical CO_2 corrosion rate for carbon steel in contact with water (wet conditions) will be in the order of 10 mm/yr. Normally, in carbon steel tubulars, CO_2 corrosion is mitigated by proper control of the water content of the CO_2 to avoid formation of free water and to prevent wet excursions. The water content in the CO_2 is specified as below 20 ppmW.
13Cr / S13Cr	Even under wet conditions, CO_2 corrosion is not a threat for 13Cr steel under typical Goldeneye injection conditions. 13Cr is susceptible to localised corrosion in wet conditions when O_2 is present. A limit of 1 ppmv for O_2 in the CO_2, corresponding to a concentration O_2 dissolved in water below 10 ppb (by mass), will prevent such corrosion from occurring.
Elastomers	Elastomers can also absorb gas and suffer explosive decompression when pressure is reduced. Any elastomers to be in contact with CO_2 need to be checked for compatibility.

6.3. Xmas tree and Wellhead

Due to low transient temperatures (in the order of -20°C in the CO_2) during opening-up and closing-in of the wells, SSSV testing and even lower temperatures which might be encountered in leak scenarios, surface trees and tubing hangers will be changed to low design temperature compatible equipment.

The current Cameron Xmas tree class U and tubing hanger is rated to -18°C will be changed to a lower temperature rating equipment. The material can be upgraded from the current 4140 low alloy steel to a maximum F6NM stainless steel which has a low temperature threshold of -60°C.

There are some well elements in the wellhead which cannot be changed during the workover. Detailed thermal simulations of the wellhead/Xmas tree system will be done to evaluate the extent of the low temperatures during leak scenarios for evaluating the suitability of the system.

6.4. Conduction and Casing Strings

6.4.1. 30" Conductor

The 30" [762mm] conductor was driven 200ft [61m] into the seabed to 750ft [229m].

From 2010 PEC (Pulsed Eddy Current) corrosion surveys, the carbon steel conductors look as though they may be falling into the higher corrosion rate category. However, load calculations for the worst case corrosion rate (0.5 mm/yr over a 25 yr period) conclude that the existing Goldeneye 30" conductors are fit for the expected load cases for the duration of the extended field life. The 30" conductor will not be in direct contact with CO_2.

6.4.2. 20" x 13 3/8" Surface Casing

The first casing string set inside the conductor was a 20" x 13 3/8" taper string set at around 4150ft. The 20" [508mm] casing features a 1" [25 mm] wall thickness. The 20" casing was cemented to seabed. The surface casing will not be in contact with the injected CO_2.

The 30" conductor and 20" x 13 3/8" [508mm x 340mm] casing are freestanding and independent of one another. The 20" surface casing takes all the well loading and does not transfer the load to the 30" conductor.

Goldeneye Platform wells have been analysed with WellCat software. The analysis also models the conditions of CO_2 injection. PEC corrosion surveys were run on both the conductor and the surface casing. There are indications that corrosion rates on both strings are relatively high. A special case has been worked up to simulate high 20" corrosion rates. Using the "high" corrosion rate of 0.5 mm/yr and a 25 year life span - both worst cases, the conclusion is that the pipe is still fit for purpose, with a Safety Factor of 2.4 for axial loading. Furthermore, at high corrosion rate the 20" casing still has several years' life left beyond the 25 year life span. Hence, the Goldeneye 20" casing will be good for the expected load cases for the duration of the extended field life. It follows that no load transfer to the conductor is expected.

6.4.3. 10 ¾ x 9 5/8" Production Casing

The second casing string or 10 ¾" x 9 5/8" [273mm x 245mm] taper production casing was set at the bottom of the Rodby formation. This casing was cemented to approximately 1500ft [457m] AH above from the casing shoe.

The position of the production packer in the current completion and the new completion for CO_2 injection will be similar but deeper. The production packer in the injectors should be positioned in the wells across the Hidra marl, considered part of the reservoir seal.

The current corrosion of the production casing above the existing packer is practically nil as the completion fluid used in the A annulus was inhibited seawater installed during the completion operations. The production casing above the production packer is not expected to be exposed to free water and CO_2 during the injection phase. Internally, the 13Cr tubing prevents contact with the injected fluid.

Underneath the production packer, a section of production casing has been exposed for the period of ~6 years to the hydrocarbon production environment. As a worst case estimate of maximum corrosion, assuming wetting for the full 6 years of field production, the corrosion loss would be of the order of 6 yrs x 0.1 mm/y = 0.6 mm. In view of protection by $FeCO_3$ scale and a much shorter wetting period (wells production was closed in only after the presence of formation water), the actual wall loss will be less.

In the same section of the production casing (underneath the production packer), the carbon steel casing would be in contact with the injected fluid. Under normal injection conditions the CO_2 corrosion rate is controlled by the water content in the CO_2. However, during non-injection periods, water from the aquifer might initially come back into the well leading to presence of water and CO_2, which can result in high corrosion rates (10 mm/yr). Based on an estimated typical CO_2 corrosion rate of 10 mm/y, it would take a little more than 1 year of wet exposure to corrode through the ½" [1.27Cm] thickness of the casing. This indicates that to avoid the casing corroding through, wet exposure to the CO_2 environment needs to be limited to less than 1 year in total over the required life of the casing.

Even in the scenario of having casing failure and radial cement degradation, the risk of leaking CO_2 is very low. This is based on the estimated matrix properties and the absence of fractures at the Hidra level. Additionally, during most of the injection period, the pressure of the CO_2 downhole will be lower than the hydrostatic pressure. As such, there is no reason to plan a sidetrack for the potential of out of zone injection of the CO_2 as the marls above the Rodby also located adequate sealing characteristics.

In the current well completion, a perforated pup joint is present below the production packer and the top of the screen hanger; this section creates a dead volume (stagnant) between the tubing and the production casing. CO_2 fluid could find its way through the perforated pup and contact the carbon steel production casing in the dead area between tubing and casing and potentially cause high levels of corrosion in the casing. Although this section is below the existing production packer, it is recommended to remove the perforated tubing section during the workover operations to give more protection to the casing and to be able to run the new production casing across the Hidra.

Due to injection of cold CO_2, the load cases are driven towards tensile loading due to thermal contraction.

Normal CS ("LT0") is adequate down to 0°C. For lower temperatures, carbon steel should be impact tested. Available certificates that supported the quality of the installed production casing were analysed and recorded Charpy values demonstrating adequate toughness down to -40°C, well below the worst case lowest casing temperature Had such information not been available, the next step would have been to assess the suitability based on the design code used, the materials specification and the wall thickness.

6.5. Cement

The primary cement sheath of the production casing is a barrier to capture the CO_2 downhole in the well. The cement used in the cementation is normal Portland class G cement.

The theoretical top of the cement (TOC) in the B-annulus between 9 5/8" [245mm] production casing and the 10 ¾" [273mm] hole has been estimated for all five wells during the cementing operations. The cement column from the 9 5/8in casing shoe to the theoretical TOC is calculated at 1,500ft [457m] AHD above the shoe, well above the formation seals of the reservoir. Cement evaluation logs were not run during the drilling phase of the wells, but are scheduled for the workover operations.

The cement is considered of good quality, based on well operation records. The historical records show that the casing integrity is good as a successful pressure test was achieved after bumping the top of the cement plug during the production casing section. The historical records of top well annuli pressures also show that no anomalies have been reported in the B annulus pressures during the production history of Goldeneye.

The distance between the currently installed production packer and the theoretical TOC is between 1,190 and 1,351ft [363 and 412m] AHD depending on the well. The cement is covering the primary seal formations (Rodby and Hidra) in all five wells up into the Chalk formation. This is sufficient cement height to ensure a barrier in the B annulus above the production packer.

Given that the TOC is theoretical, it is recommended to run a cement evaluation tool to better assess the condition of the cement in the B-annulus during the proposed workovers of the upper completion.

The long term effect of CO_2 on cement has been investigated. Cement degradation by CO_2 in the form of carbonic acid is a process that produces an insoluble precipitate that slows degradation. Several recently published papers examine various experiments or case studies that examine the potential degradation of Portland based cements when exposed to high CO_2 environments.

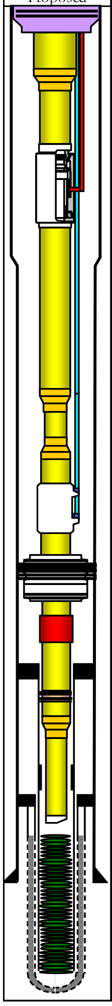
Degradation rates are proportional to temperature, pressure and the square root of time. From literature, estimates for cement degradation vary from 0.05m in 10,000 years to 12.36m in 10,000 years. Goldeneye conditions ~2m in 10,000 years.

Diana software, a specialist mechanical cement model has been run to ascertain the thermal effects of CO_2 injection on Goldeneye. The injection model simulates the thermal effects on the mechanics of the system (casing / formation / cement). Diana results indicate that the remaining integrity of the cement is sufficient for CO_2 injection in the Goldeneye Platform wells. The remaining capacity of the cement sheath for various simulated operational scenarios is sufficient for CO_2 injection in the Goldeneye Platform wells.

6.6. Completion

Single small tapered completion has been selected as the reference case during the workovers, (PCCS-05-PT-ZW-7180-00003 Well Completion Concept Select Report, 2014). The lower completion will remain in place.

6.6.1. Selected Completion



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

Figure 6-1: Proposed Generic Completion Schematic

6.6.2. Completion Components

Table 6-2: Completion Components

Tubing materials	13 Cr S13 Cr from Xmas tree to TRSSSV The generally accepted low temperature limit for 13Cr steel is from -10 to-30°C (depending on manufacturer) and for Super 13Cr it is estimated at -50°C. In any case, impact testing of 13Cr or Super 13Cr tubing will be required for equipment to be run in the wells (especially in the top part of the wells, where extreme low temperatures are expected during transient conditions and loss of well control scenarios).
Tubing size	4 ½" and 3 ½" [114mm and 89mm] (different length sections in the wells)

	It is proposed to standardise the top (from surface down to the SSSV) and the bottom (up to the PDG) of the upper completion for the CO_2 injection in all wells. SSSV to Xmas tree ~ 4 ½" S13Cr The exact position of the X-Over 4 ½" x 3 ½" will be defined during FEED. The bottom of the upper completion (up to the PDG) will require to be defined during FEED. Option exist for 3 ½" or 4 ½" type of completion.
SSSV	Yes - 2550ft [777m] TVD The final depth of the SSSV will be validated during FEED
Production packer	The packer should be positioned in the well across the Hidra marl, considered part of the primary seal. The screen hanger is either set at the Rodby formation or the Hidra formation. Currently, the packers in GYA01 and GYA05 are set in the Chalk group. A production casing evaluation tool will be run during the workover of the wells to assess the condition of the production casing strings and optimise the position of the packer.
In-well monitoring	PDG – Permanent Downhole Gauges DTS – Distributed Temperature Sensors DAS- Distributed Acoustic sensors being considered (using the same fiber optic than the DTS)
"A" annulus fluid (packer fluid)	Different options available: • Base oil with N_2 cushion • Water based brine with N_2 cushion • Water based brine Annular fluids will be selected during FEED.
Non return valve	The requirement for installing a non-return valve will be studied during FEED. The objective is to minimise the inventory of CO_2 release to the atmosphere in case of a surface leak and failure of the SSSV.
Connection between Lower and Upper Completion	Two options available: • Stab the tail pipe without sealing mechanism. Under this case more casing is exposed to CO_2. This option is preferred as the production packer will be installed at the Hidra level, which is part of the CO_2 subsurface seal and it is expected that dry CO_2 will displace and evaporate water from the wellbore, reducing the corrosion rate of the production casing. • Seal-off the casing between the production packer and the screen hanger. Stagnant fluid present. Cold injection will

	generate vacuum conditions. Management of this connection will require likely additional completion components. Option to be defined in FEED phase.
Lower Completion	NO changes required. The lower completion will be left in place during the workover activities. The lower completion of the wells consists of open-hole gravel packs including premium screens and pre-drilled liners – alternate path system. Main elements are: 7" [178mm] pre-drilled liner across the reservoir, 4" screens, 20/40 gravel between the hole and the screens and FIV 2.94" [74.7mm] ID. The top of the screens are at the Hidra marl level. Filtration in the platform is planned to minimise the risk of erosion and plugging of the lower screen and formation.

7. Well Management

7.1. Well Intervention

Intervention operations will be carried out on Goldeneye platform to confirm well integrity, to collect bottom hole samples and to monitor the progress of the CO_2 plume as it moves through the reservoir.

The selected completion allows for well intervention by means of wireline or coil tubing for surveillance and potential remedial activities.

Wireline and coiled tubing interventions may be limited due to either tubing size or to the way the well is completed. Downhole equipment with very small internal diameter may restrict intervention.

Wireline intervention work was carried out on Goldeneye platform during 2012 when a number of suspension plugs were installed. For the CO_2 service the requirement is to leave the same deck space available as in the hydrocarbon phase. Coil tubing intervention needs to be assessed during FEED but it is likely it will require a support vessel.

2.92" [74.2mm] is the ID of the FIV installed in the lower completion. This will determine the size of the tools to be used to access the reservoir level.

2.992" [76mm] is the ID of the 3 ½" [89mm] tubing

Table 7-1: Well Surveillance. Proposed well intervention

Well sampling	Sporadic
Saturation profile	Sporadic
Corrosion monitoring – tubing caliper logs	Variable frequency with time – wireline intervention
Temperature logging (down of the DTS bottom)	Variable frequency with time – wireline intervention, if required

7.2. Well Monitoring

Surface pressure and temperature sensors for the tubing and well annuli need to be installed and transmitted live to the control room and the office in Tullos.

There is also a requirement to transmit live the pressure/temperature of the SSSV system.

Integrity monitoring of the well will form part of the planned inspection regime for the wells.

Table 7-2: Well Surveillance. Proposed Monitoring

Activity	Frequency
Manifold Pressure (MFP)	Continuous
Manifold Temperature (THT)	Continuous
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
Subsurface Safety Valve (SSSV) test	6-monthly to be evaluated post FEED
Well Integrity Tests (WITs) including Xmas Tree Valves	Annual
Non-flow wetted Valves (SITs)	Bi-annually

7.2.1. In-well Monitoring

In-well monitoring related to Permanent Downhole Gauges (PDG), Distributed Temperature Sensor (DTS) and possibly Distributed Acoustic Sensors (DAS) will be installed in the five existing wells. The number of cables and tubing hanger penetrations required will be defined in the FEED phase.

Table 7-3: Well Surveillance. Proposed In-well monitoring

Activity	Frequency
Permanent Down-hole Gauges (PDGs)	Continuous with data transmission to shore Multiple gauges to be installed in each well Possibility to install an "A" annulus reading down in the well in the case of completing the well with a N2 cushion in the "A" annulus.

Temperature Measurement along well bore with Distributed Temperature Sensors (DTS)	Continuous with data transmission to shore
Distributed Acoustic System (DAS)	Continuous with data storage on the platform Currently under evaluation

7.2.2. Monitoring well

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 arrival time in this well in order to allow calibration of the reservoir model. The well is the most north-westerly well that is nearest to the structural spill point.

7.3. Filtration

The wells each have a non-cemented completion with gravel pack and sand screens, which are to be re-used. The risk of plugging posed to these completions and the formation rock from fines from the offshore pipeline (residual material after cleaning or from potential de-lamination of an internal coating) is being mitigated by the installation of a filtration package on the platform. Five microns is the maximum acceptable particulate size for Goldeneye CCS wells.

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.

There is a likelihood that following seven years of production, debris will exist in the offshore pipeline (corrosion products, sand etc.). When flow is reversed in the pipeline, displacement of these products into the wells without any mitigation measures would 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.

7.4. Hydrates

The formation of hydrates is only possible when water is present in sufficiently significant quantities and the temperature and pressure of the fluid is within the hydrate formation window.

During hydrocarbon production, water encroached into the Goldeneye gas cap and at least part of the well gravel pack will be surrounded by water at the time that injection commences. The trapped gas saturation is estimated to be 25%, so some methane will remain near the well. The methane is miscible with CO_2. Consequently, it will eventually be displaced by the injected CO_2. The initial injection of CO_2 will drive water away from a well and cool the reservoir.

To reduce the risk of hydrate deposition it is proposed to displace methanol as hydrate inhibitor between the SSSV and the Xmas tree when the well is closed in prior to operational opening of a well for injection purposes and water is suspected to be present in the well. (Continuous methanol injection is not recommended.)

Batch hydrate inhibition will feature as an instruction in the well operational procedures that will be developed for the injection system.

The volume of methanol to be displaced in the well when the well is closed in is calculate in 6.1m^3 based on a 4.5" [114mm] tubing and a SSSV setting depth of 2,550ft [777m]. The available pressure of the methanol system at the wellhead is estimated at 225bar which allows for methanol displacement in the well when the well is filled with hydrocarbon gas.

7.5. Remedial activities

No further hydraulic workovers are planned (planned workovers to increase the capacity of the wells by increasing the size of the tubing once the reservoir pressure is increasing).

Remedial activities might be carried out in case of well failure. These may involve (outline in the Corrective Measures Plan):

- Leaking tubing: sealant, patching the tubing, straddles or tubing replacement (workover)
- Leaking production packer: packer repair with cement, workover, install a new packer, leaving the current in place
- Lower Completion failure: coil tubing or wireline intervention. Stimulation. Bullheading of chemicals, sand clean-out
- Production casing failure: casing patch, re-drill, repair casing, abandonment, sidetrack, casing replacement.
- Cement Failure: Sidetrack, abandonment.
- Halite precipitation: water bullheading, coil tubing.

7.6. Well abandonment

Abandonment concepts and their reasoning are described in the document (PCCS-05-PT-ZW-7180-00001 Abandonment Concept for Injection Wells, 2014).

In summary:

- Permeable zones requiring abandonment:

  Captain sandstone: Formation receiving the CO_2. It will contain hydrocarbon, water and CO_2. Hydrostatically pressured (~3500-3800psi [241-262bar]) or slightly depleted after CO_2 injection. The primary seal for the Captain reservoir is the Rodby shales/Hidra marl. These formations are impermeable, strong and about 500ft [152m] in vertical thickness. In Goldeneye, these formations are positioned right above the Captain reservoir.

  Tertiary sandstones (Balmoral, Dornoch): water bearing, hydrostatically pressured. However, in case of CO_2 leakage into this formation then CO_2 will need to be considered for the abandonment. The Balmoral sandstone formation is contained by the Lista shales.

- Number of cement plugs

  Over-pressured permeable zones (both water and hydrocarbon bearing) and normally pressured permeable zones containing hydrocarbons require a minimum of two Permanent (abandonment) barriers between the permeable zone and seabed/surface.

  Normally pressured permeable zones containing water require one Permanent (abandonment) barrier between the permeable zone and seabed/surface.

- Cement

  The reference case for cement plugs is Portland cement. The type of cement to be used will be reviewed later and may include CO_2 resistant additives. Some alternatives to cement (like resins, etc.) may be considered as well. This will be influenced by the best practices and standards of the day at the time of abandoning.

- Geometry of cement plug

  Two options exist for the primary seal: rock to rock cement plug or internal and external with pipe.

  The reference case for cement plugs is Portland cement. The type of cement to be used will be reviewed later and may include CO_2 resistant additives. Some alternatives to cement (like resins, etc.) may be considered as well. This will be influenced by the best practices and standards of the day at the time of abandoning.

Three abandonment concepts/possibilities are described below:

7.6.1. Abandonment Proposal 1

For this proposal, it has been assumed that (some of the) CO_2 has migrated to the Balmoral formation and is therefore present in both the Captain reservoir and the Balmoral formation. Each formation will therefore require a minimum of two permanent barriers between the formation and seabed.

The rock to rock cement plug concept is used for placement of a permanent barrier over the Rodby shales. In order to achieve this, most of the completion components need to be removed.

The deep-set barrier above the Captain reservoir, is achieved by section milling production casing and cement opposite the Rodby shales. This gives "rock-to-rock" cement coverage, the best possible solution.

For this proposal, the idea is to place two cement barriers at this level; the first one is the cement plug (plug#1) set over the section-milled window.

The second barrier (plug#2) will be placed directly on top of (plug#1) in order to make best use of the removal of completion components and getting deep into the cap-rock. The second barrier is supported on the outside of the production casing by annular cement from the primary cementation and partly the cap-rock (Hidra marl).

The third barrier (plug#3) around the 13 3/8" [340mm] casing shoe is set in the open hole in order to get a barrier opposite the Lista shales (seal).

The fourth barrier (plug#4) is required since the Balmoral sands in this case are CO_2 bearing and this plug will act as the second permanent barrier for the Balmoral sands. Its position will be opposite the Dornoch shales. See Figure 7-1 for more details.

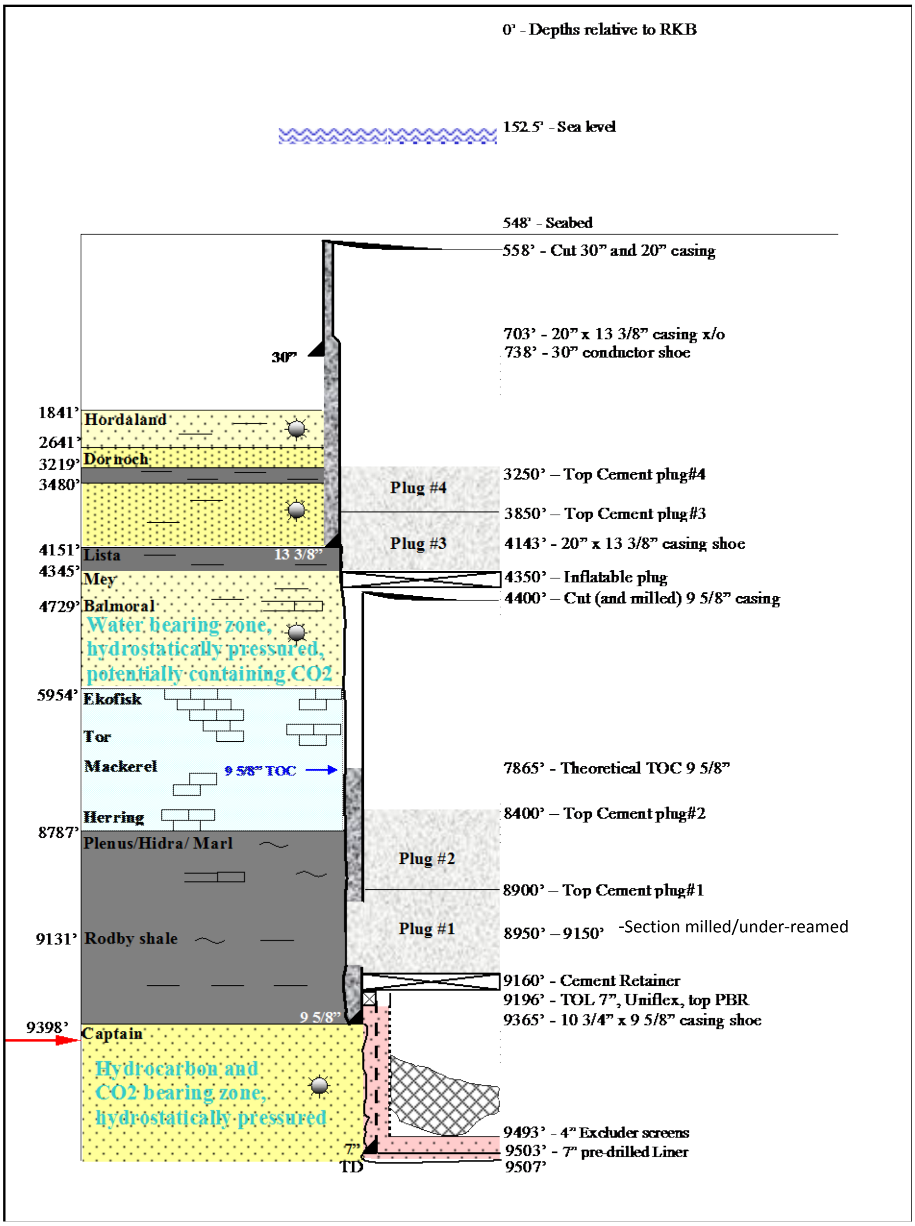


Figure 7-1: GYA03. Abandonment Proposal 1

7.6.2. Abandonment Proposal 2

For this proposal, it has been assumed that (some of the) CO_2 has migrated to the Balmoral formation and is therefore present in both the Captain reservoir and the Balmoral formation. Each formation will therefore require a minimum of two permanent barriers between the formation and seabed.

For the wells with the production packer positioned at the Chalk level, the production packer will have to be removed in order to get deeper into the well to the reservoir sealing formations (Rodby shales/Hidra marl). For this particular well it will be difficult to get two individual permanent barriers installed at the Rodby/Hidra level, even with removal of the SC-2R packer and 200ft [61m] of window milling. This is due to the relative position of the completion components to the sealing formations. The second permanent barrier (plug#2) for the Captain reservoir will therefore be the same as the first permanent barrier for the Balmoral.

The Balmoral formation is assumed for this proposal to have been charged with CO_2 and therefore requires two permanent barriers opposite the Lista shales for containment. The Lista shales are the seal for the Balmoral formation. Since two permanent barriers are required at the Balmoral level, the second barrier at this level (plug#3) will be set on top of (plug#2) opposite the Dornoch shales.

7.6.3. Well Abandonment Proposal 3

For this proposal, it has been assumed that the CO_2 is contained at the Captain reservoir level only. The Balmoral formation is therefore water bearing and hence only requires a single barrier from surface.

Due to the position of the production packer in relation to the caprock, it is believed that only a single barrier (plug#1) can be placed above the packer taking the TOC and the formations behind the casing into account. The Chalk formations are assumed not to be a seal due to the presence of micro-fractures. This proposal is only an option for wells with the production packer positioned across the Rodby/Hidra formations with sufficient height for a cement column to the top Hidra.

The second barrier (plug#2) is placed across the Lista formation and also serves as the single barrier for the Balmoral formation. See Figure 7-2.

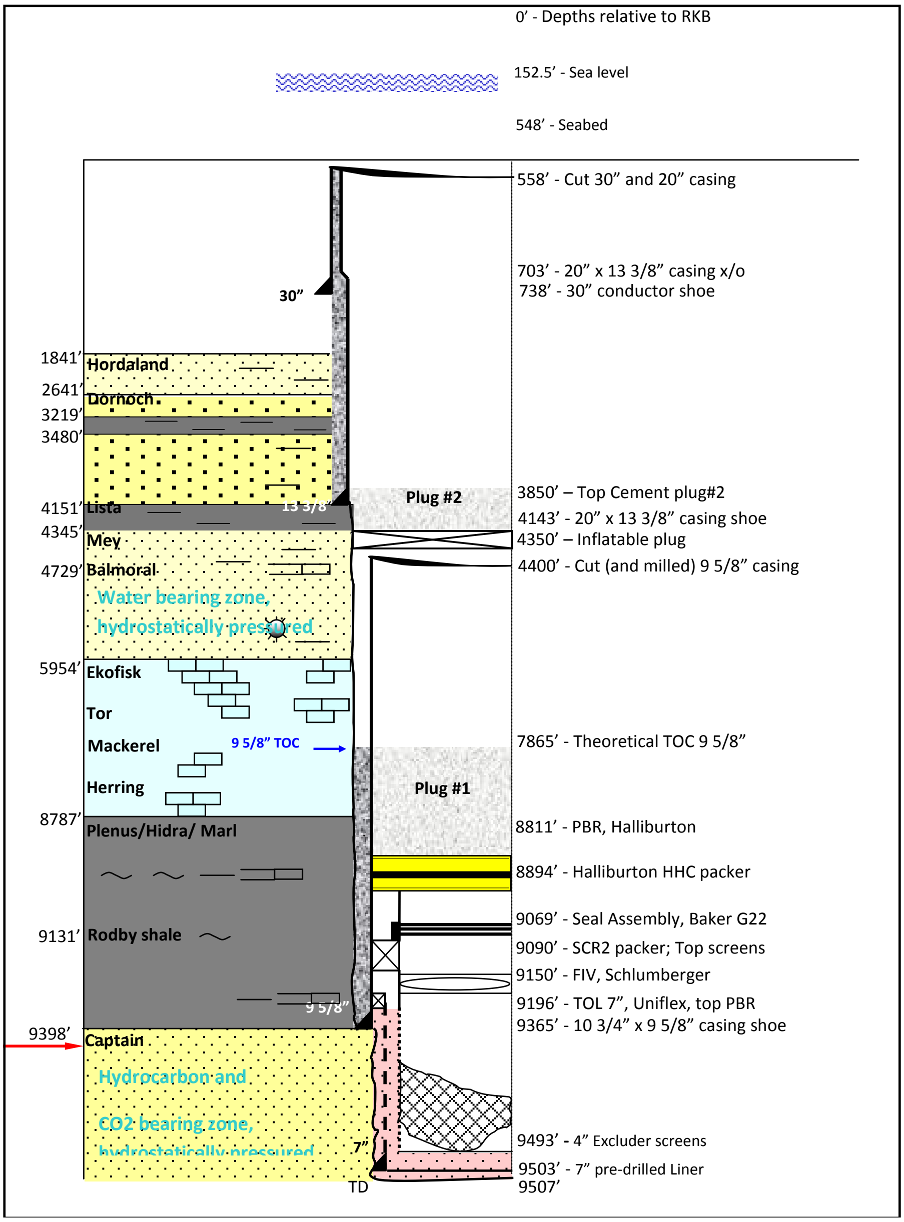


Figure 7-2: GYA03. Abandonment Proposal 3.

The abandonment of the injection wells will be carried out after the injection phase (~20 years in the future). At that time, the well abandonment will be carried out according to the existing guidelines and best industry practices. Planned data gathering during the conversion workover such as cement logging and casing calliper logs will help to develop an understanding of the cement quality, top of cement and casing condition. The packer will be set across the primary seal which will facilitate the abandonment operation. Based on the well condition and available information the abandonment concept will be selected on a well by well basis.

8. Number of wells

The Peterhead CCS bid submission, made in mid 2012, included ***four*** wells converted for injection/monitoring, with the recommendation to decide the way forward of the fifth well during further stages of the project.

The number of required injector wells depends mainly on the injection estimates (reservoir pressure and injectivity), capture plant rates, CO_2 management, monitoring requirements and life cycle risk management.

The well(s) not converted for CO_2 injection will also need to be considered for the Peterhead project. Options included are to complete as an injector/monitor or to abandon the well.

The installation of small bore tubing in the wells limits the operating envelope of each well. In order to accommodate the range of injection rates at the different reservoir pressures during the injection life, each well will be completed with a different tubing size/configuration tailored to a specific rate range. The wells will then have overlapping operating envelopes and any rates specified in the integrated consortium basis-for-design will then be achievable through the choice of a specific combination of wells.

A single well will not be able to inject from the minimum to the maximum CO_2 injection rate for the duration of the project. This is due to the limited injection envelope per well and the increase in reservoir pressure with injected CO_2. By using multiple wells, several different completion sizes should be designed such that they can handle fluctuating injection rates arriving at the platform.

The current plan is to recomplete the five existing production wells by means of a workover – replacing upper completion. Whilst purely for CO_2 injection, based on the latest scheduled volumes of captured CO_2 from the Peterhead power plant, there is a requirement for three injection wells only. There is an additional requirement for one monitoring well (GYA03) and a decision was made to convert the remaining fifth well to CO_2 injection, instead of abandonment or long-term suspension. This decision will be re-evaluated during early FEED phase.

9. Initial Well Modifications

The workover required to change the wells from hydrocarbon production to CCS will involve the replacement of the existing upper completion with a tapered slim string.

The workover will take place prior to commencing any CO_2 injection hence the workover shall be in a hydrocarbon environment. A workover of this nature is standard within the industry and does not involve any extra complexity compared to other workovers carried out in a similar environment.

The reservoir will be sub-hydrostatic at the moment of the workover. The exact depletion level will be defined close to the workover operation as the reservoir pressure is currently increasing with time. A heavy duty jack-up is required (~400ft [102m] of water). One of the challenges will be the availability of a suitable jack-up rig as the Goldeneye platform lies in a water depth of 400ft.

During the operation diligence will have to be paid to the lower completion which is not planned to be replaced. In addition the reservoir is depleted and all measures must be taken to avoid formation damage and skins. Measures to ensure this will be explored and may involve a mechanical or fluid barrier.

Prior to running the new completion logging operations will be carried out. These shall involve CBL and casing calliper runs. This will help evaluate the top of cement, quality of cement bond and condition of the casing. It is essential to carry this out for correct packer placement and future abandonment.

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11. Glossary of terms

Term	Definition
13Cr	13 percent chrome content metallurgy
'A' annulus	Annulus between the production tubing and production casing string
Annuli	The space between adjacent strings of tubing or casing
'B' annulus	Annulus between the production casing and intermediate casing string
Barrier	Barriers prevent of mitigate the probability of each threat or prevent, limit the extent of, or provide immediate recovery from the Consequences
Base oil	Oil with carcinogenic elements removed
BHP	Bottom Hole Pressure
BHP&T	Bottom Hole Pressure and Temperature
Blowout	Uncontrolled release via the wellbore to surface
BOP	Blow Out Preventer
Cap rock	The shale layers above a reservoir that provide geological isolation to upward migration and provide the primary seal
CBL	Cement Bond Logging
CCS	Carbon Capture and Storage
Cement squeeze	Injection of cement to isolate a leak in the cement behind casing
CITHP	Closed-In Tubing Head Pressure
CO_2	Carbon Dioxide
Completion	The conduit for production or injection between the surface facilities and the reservoir. The upper completion comprises the tubing and packer, etc. The reservoir completion is the screens, etc., across the reservoir interval.
CoP	Cessation of Production
CTU	Coil Tubing Unit
DAS	Distributed Acoustic Sensing
DECC	Department of Energy and Climate Change
DIANA	Software package from TNO that solves, with the aid of FEM, problems relating to design and assessment activities in concrete, steel, soil, rock and soil-structure.
DP	Differential Pressure
DTS	Distributed Temperature Sensing
ECP	External Casing Packer
EOR	Enhanced Oil Recovery
FEED	Define phase of the project - Front End Engineering Design

FIV	Formation Isolation Valve
FWHP	Flowing WellHead Pressure
FWHT	Flowing WellHead Temperature
FWL	Free Water Level
HHC	Halliburton Hydrostatic Set Retrievable Packer
ID	Inside Diameter
JT	Joule-Thomson
MFP	Manifold Pressure
MFT	Manifold Temperature
MMscfd	Million Standard Cubit Feet
MMV	Measurement, Monitoring and Verification
NUI	Normally Unattended Installation
Open shoe	An annulus that is open to a formation
Packer	A device that both anchors and seals the tubing to the production casing. The term production packer is still used even when the well is in injection mode
PBR	Polished Bore Receptacle
PDG	Permanent Downhole Gauge
PDHG	Permanent Down Hole Gauge
PEC	Pulsed Eddy Currency
Production casing	The casing providing the secondary wellbore barrier during production or injection (valid term even in injection mode)
PVT	Pressure, Volume, Temperature
Relief well	A well constructed specifically to intersect the wellbore or reservoir of a blowing out well
RKB	Rotary Kelly Bushing
S13Cr	Super 13 percent chrome content metallurgy
SITs	Non-flow wetted tests
SSSV	Sub Surface Safety Valve
Straddle	A device comprising two packers and tubing designed to isolate leaking tubing or casing
TDS	Total Dissolved Solids
TOC	Top of Cement
TRSSV	Tubing Retrievable Subsurface Safety Valve
TVD	True Vertical Depth
TVDss	True Vertical Depth sub-sea
WFS	Well Functional Specification

WITs Well Integrity Tests

XLOT Extended Leak Off Test

12. Glossary of Unit Conversions

For the provision of the SI metric conversion factor as applicable to all imperial units in the Key Knowledge Deliverable.

Table 12-1: Unit Conversion Table

Function	Unit - Imperial to SI Metric conversion Factor
Length	1 Foot = 0.3048m Metres 1 Inch = 2.54cm Centimetres 1 Inch = 25.4mm millimetres
Pressure	1 Psia = 0.0690 Bara
Temperature	1°F Fahrenheit = -17.22°C Centigrade
Weight	1lb Pound = 0.45kg Kilogram