Peterhead CCS Project

Doc Title: Well Technical Specification

Doc No.: **PCCS-05-PT-ZW-7770-00001**

Date of issue: **20/05/2015**

Revision: **K03**

DECC Ref No: **11.099**

Knowledge Cat: **KKD - Subsurface**

KEYWORDS

Goldeneye, CO_2, Carbon Capture and Storage, Technical Specification, Wells, Completion, Materials, Intervention.

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 Goldeneye platform consists of five wells which were completed as hydrocarbon producers and are currently suspended. To retain well integrity over the injection life the existing wells require a workover (re-completion). This requirement is explained in the Conceptual Completions and Well Intervention Design Report (Key Knowledge Deliverable 11.093) (1). It is planned to workover three of the wells for CO_2 injection and one well as a monitoring well.

The purpose of this document is to identify the technical requirements required to deliver the wells and to establish the basis of how the wells will work and how they will be built. It also provides an update to and builds upon information previously included in the Well Functional Specification (Key Knowledge Deliverable 11.098) (2).

Establishing the technical requirements at this stage of the well delivery process allows the well design to be developed in accordance with the expected conditions over the lifecycle of the project.

The report includes relevant information on:

- Well specification and expected conditions.
- Reservoir information and field geology.
- Expected injection conditions: rate, pressure and temperature.
- Material selection.
- Casings, conductor and cement.
- Upper completion design and component evaluation.
- Lower completion evaluation.
- Fluids, completion and packer fluid selection.
- Well start-up requirements.
- Well intervention operations.

The document identifies the well technical requirements from the Well Functional Specification (2) and in doing so highlights the challenges in developing the conceptual design into a robust and technically sound detailed design. Areas of the design requiring further development have been identified and a forward plan has been developed to continue to mature the well design. There are no fundamental concerns with the constructability or execution of the proposed workovers and the well design can be developed to deliver the specified project requirements.

For clarification the Select Phase is pre Define/pre FEED phase, The Define phase is the FEED phase and the Execute phase is post FEED.

1. Introduction

The Goldeneye platform consists of five wells which were completed as hydrocarbon producers and are currently suspended. The requirement for working over (re-completing) the wells to make them suitable for CO_2 injection and to retain well integrity over the injection life is demonstrated in the Conceptual Completion and Well Intervention Endorsement Report (Key Knowledge Deliverable 11.093) (1) and the Well Functional Specification (Key Knowledge Deliverable 11.098) (2). It is planned to workover three of the wells for CO_2 injection and one well as a monitoring well for reservoir surveillance.

The well technical specifications are translated from the Well Functional Specification (WFS) (2) directly after the concept select phase. The Well Technical Specification (WTS) report identifies and records the technical requirements for delivery of the completion in accordance with the WFS (2).

For clarification the Select phase is pre Define/pre FEED phase, The Define phase is the FEED phase and the Execute phase is post FEED.

1.1. Asset description & storage development

A summary of The Storage Development Plan (Key Knowledge Deliverable 11.128) (3) is presented in this section for easy reference and to illustrate the main elements of the CCS system.

During the yearly updates of the WRM (Well and Reservoir Management) plan (Key Knowledge Deliverable 11.126) (4) this section should include a summary of the activities carried out in the previous year and their implications on the asset surveillance, management of the asset, and plans for MMV.

The Peterhead Carbon Capture and Storage (CCS) project proposes to separate, capture and permanently store CO_2, thereby reducing greenhouse gas emissions from the Peterhead power plant. Around 1 million tonnes per annum, of 99% purity CO_2, will be injected over a period of up to 15 years for storage in the UK Continental Shelf within the depleted Goldeneye hydrocarbon field. The Storage Development Plan (1) details the main parts of the development.

The three main components of the Peterhead CCS project are:

- Post-combustion removal of CO_2 from a portion of the flue gases from Peterhead power station by retrofitting the power station with a Carbon Capture & Conditioning Plant (CCCP). This part of the project falls out with the scope covered by this document.
- The captured CO_2 will be conditioned, compressed and transported in a dense phase via a portion of new build offshore pipeline and then the majority of the re-tasked 102 km Goldeneye gas export pipeline to the Goldeneye platform (Figure 1-1) in the North Sea.
- The CO_2 arrives at the platform where it is filtered before injection into the reservoir. The CO_2 flows to an injection manifold where the flow will be directed to one or more wells. Reusing existing hydrocarbon production wells, the CO_2 will be injected into the depleted Goldeneye gas field for geological storage, at a rate of approximately one million tonnes per annum.

  The injection target is the upper part of the Captain 'D' sub-unit where the CO_2 will displace and mix with the remaining reservoir hydrocarbon and the aquifer water that has swept the reservoir during production (Figure 1-2). The CO_2 will refill the voided hydrocarbon structure. As the refilling takes place there will be a front of CO_2 moving though the original hydrocarbon volume, displacing the invaded water.

The reservoir pressure will increase due to the CO_2 injection and the aquifer recharge.

Figure 1-1: Goldeneye Platform

The same document (3) highlights the plan for the Peterhead CCS, in summary:

- Following capture, compression and conditioning at the Peterhead Power Station the dense phase CO_2 will be metered prior to transfer into a pipeline system.
- It will be transported from the power station in a short new build pipeline tied into the existing undersea Goldeneye pipeline.
- The current Goldeneye hydrocarbon processing facilities at St Fergus will not be required but the MEG (Mono Ethylene Glycol) system will be converted to methanol and reused.
- The 20" [508 mm] offshore pipeline will be cleaned and reused after testing for integrity. Some valves and spool pieces will need to be replaced. The CO_2 will be transported in dense phase at a pressure of around 1740 psia [120 bara].
- In addition to the 20" CO_2 export pipeline, the existing 4" pipeline from St Fergus will be reused to enable injection of methanol into the wells.
- The Goldeneye platform will be reused. The installation is normally unmanned which is suitable for CO_2 operations. Hydrocarbon producing facilities will be decommissioned. Vent and safety systems will be modified for CO_2 service and much of the pipework will be replaced with low temperature rated pipework. Filtration equipment will be installed in the platform.
- Goldeneye production wells will be reused for CO_2 injection. The completions will be replaced to accommodate the phase behaviour of the CO_2.
- The system is required to handle varying CO_2 rates from the capture plant, ranging from 89.3 to 137.05 tonnes per hour.
- Five existing wells are available for injection. Three wells will be recompleted as injectors, the fourth well will be used for monitoring and the fifth well will feature a subsurface abandonment with downhole cement plugs at the primary seal level.
- At any specific flow rate, one or two out of a selection of three injector wells will be called upon to provide the desired surface and subsurface pressures.

- Transient well operations (closing-in, starting-up and subsurface safety valve (SSSV) testing) are operations which require attention and monitoring.
- Late in injection life as the CO_2 plume grows the value of information from well monitoring will reduce allowing the monitor well to be used as a spare late-life injector.
- The fifth well will be a subsurface abandonment with downhole cement plugs at the primary seal level. Monitoring of this partially abandoned well would be performed during the project injection period. Information will be gained for assessing the final abandonment of this well and the rest of the injectors at the end of the life of the project.
- CO_2 injection rates will be metered at the platform and at the wells and integrity monitoring will take place. Conformance monitoring of the CO_2 injection will be executed as will containment and environmental monitoring.
- The wells each have a non-cemented completion with gravel pack and sand screens. These are to be re-used. The risk of plugging posed to these completions from fines in the offshore pipeline (residual after cleaning or from potential de-lamination of an internal coating) is being mitigated by the installation of a filtration package on the platform.
- The CO_2 injection facilities will be decommissioned at least 1.5 years after the end of injection and post-closure monitoring will be executed until handover of the CO_2 store to the UK authority.

The CO_2 will be injected into the storage site at a depth >8255 ft [2516 m] below sea level into the previously gas bearing portion of the high quality Captain Sandstone Member – in total 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 produced 568 Bscf [16.1 Bscm] of gas and 23 MMbbl [3657 MMl] of condensate. During production, the field experienced moderate to strong aquifer support – which also served to end the gas production from the wells as each well sequentially cut water.

The primary CO_2 storage mechanism will be accommodation in the pore space previously occupied by the produced gas and condensate from the Goldeneye field. A secondary mechanism will be immobile capillary trapping in the water-leg below the original hydrocarbon accumulation combined with dissolution of CO_2 in the formation water.

When CO_2 is injected into the field it will displace the invaded aquifer back into the aquifer. The CO_2 will form a layer due to gravity and unstable displacement effects and some of the injected CO_2 be displaced towards and possibly below the original oil-water contact. Once CO_2 injection has stopped the CO_2 is predicted to flow back into the originally gas bearing structure. However, between 20% and 30% of the CO_2 that was displaced into the water-leg will remain trapped in place due to capillary forces.

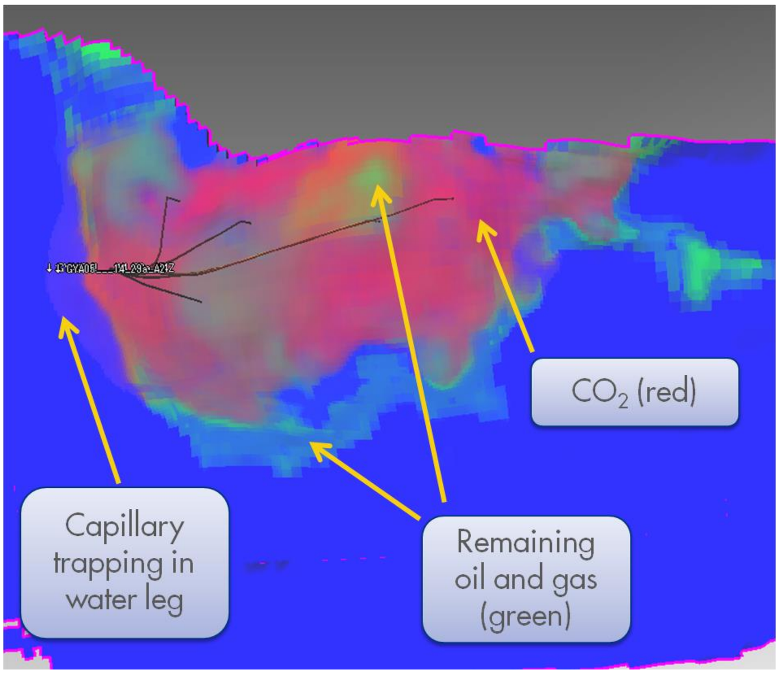


Figure 1-2: CO_2 plume after injection. Green: hydrocarbon, Red: CO_2, Blue: water

Analysis and modelling have shown that the field and water-leg have sufficient capacity to store over 30 million tonnes of CO_2 – more than sufficient for the 15 million tonnes proposed in the UK competition.

The Goldeneye field is hydraulically connected through the Captain Aquifer water-leg to the neighbouring fields in the east (Hannay, 14/29a-4 discovery – named Hoylake by Shell – and Rochelle) and in the west (the no longer producing Atlantic & Cromarty fields and, potentially the still producing Blake field). The pressure support from the Captain Aquifer has limited the decline in Goldeneye pressure, from an original of 262 bara to a little under ~145 bara (at datum level of 2560 m [8400 ft] TVDSS).

Injection of 15 million tonnes of CO_2 will raise the pressure in the main interval, the Captain D to around ~259 bara at the end of injection.

Vertical containment is provided by the 130 m thick *storage seal*, a package including part of the Upper Valhall Formation, Rødby Formation, Hidra Formation and the Plenus Marl Bed. No gas chimneys are observed above the Goldeneye complex. The sealing capacity of the Rødby Formation is considered to be excellent as it acts as the primary seal for all hydrocarbon fields in the Captain fairway.

The site contains four exploration and appraisal (E&A) wells within the Captain reservoir and one immediately to the north (Figure 1-3). All of the E&A wells have good quality abandonment plugs at reservoir seal level.

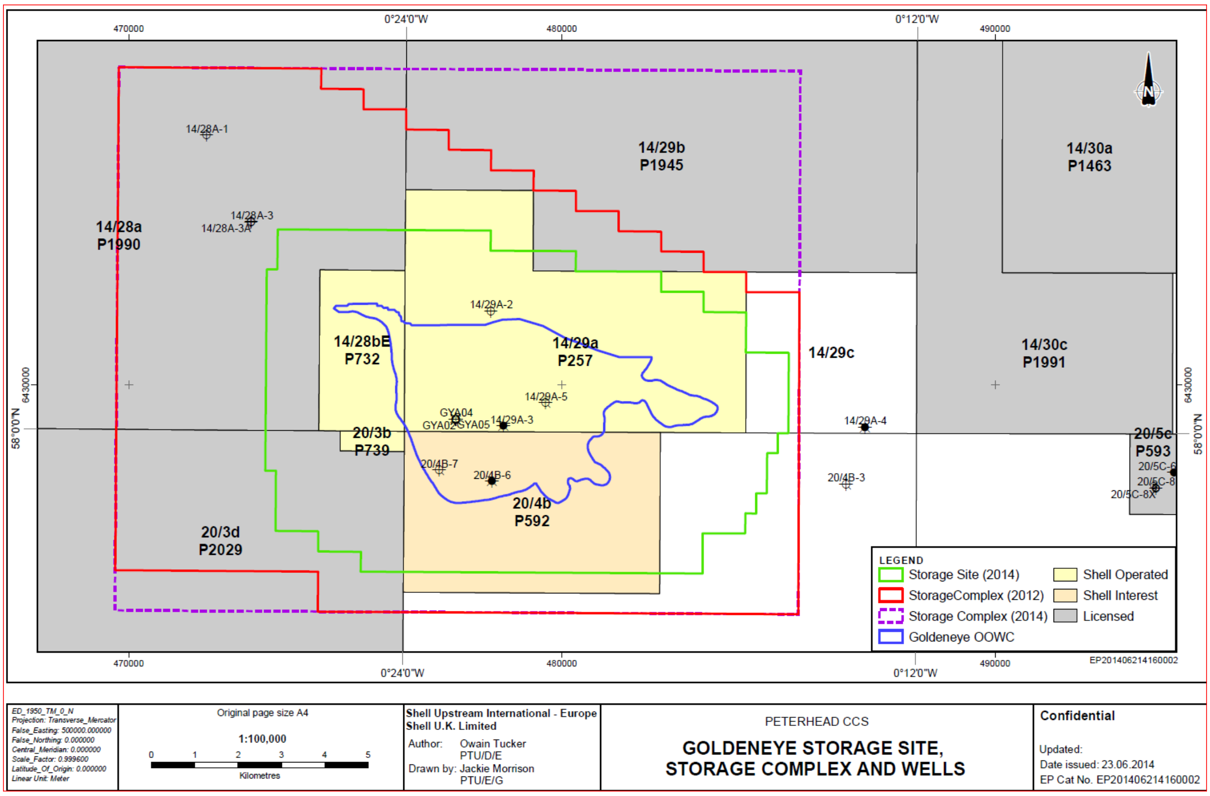


Figure 1-3: Wells in the site (demarked by green line).

1.2. Summary of Content

This document outlines the information needed to define the technical requirements of a well. It differs from the WFS (2), which looks at how the system works rather than how it is going to be constructed. The WFS (2) states the requirements and the WTS builds on these and specifies the activity in more detail.

As part of the project the Goldeneye wells specification changes from hydrocarbon production to CO_2 injection. It is therefore essential to ensure that the wells can accommodate the new conditions detailed in the WFS (2). This document presents the WTS of the planned base case i.e. well workovers on the Goldeneye platform for CO_2 injection.

The Technical Specification includes:

- Well Specification.
- Reservoir Information.
- Expected injection conditions: rate, pressure and temperature.
- Material selection.
- Casings, conductor and cement.
- Upper completion design.
- Lower completion design.
- Fluids, completion and packer fluid.
- Well start-up requirements.
- Well intervention operations.

The Figure 1-4 taken from the WFS (2) summarises the changes required to the existing wells for conversion to CO_2 injection. These requirements were identified early during the select phase and have been incorporated in the completion and well intervention detailed design. Some of the highlighted changes such as the SSSV and its qualification are part of ongoing technology maturation and require further attention during the later phases of the project i.e. execute and operation.

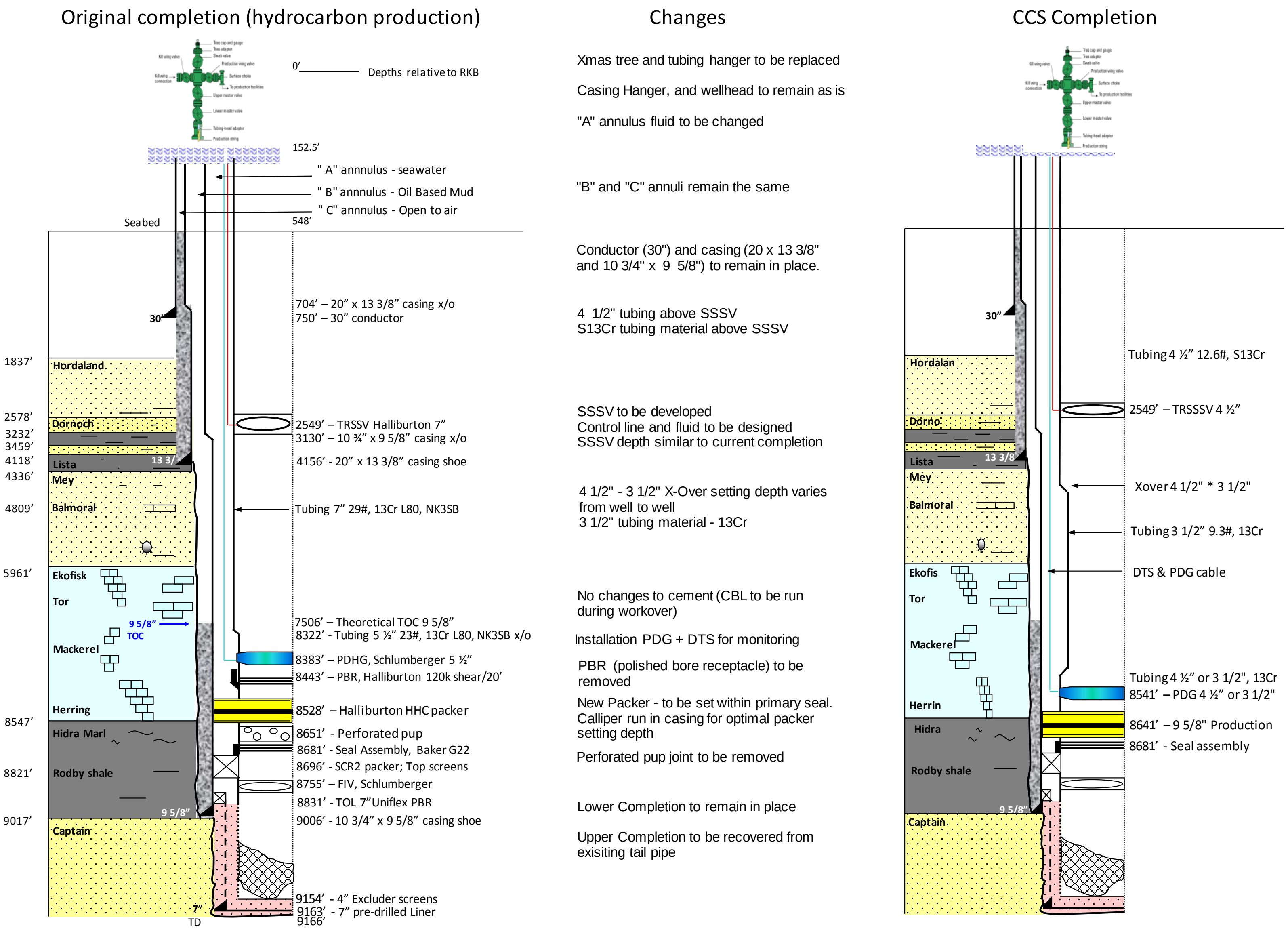


Figure 1-4: Summary of changes required during workover for CCS operation.

2. Goldeneye wells

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 were drilled and completed to produce hydrocarbons from the Captain Sands, Table 2-1 . The abbreviated well names are used in this document.

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	5/10/2003
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.

For completeness information from the Conceptual Completion & Well Intervention Design Report (Key Knowledge Deliverable 11.093) (1) and WFS (2) has been included in this section.

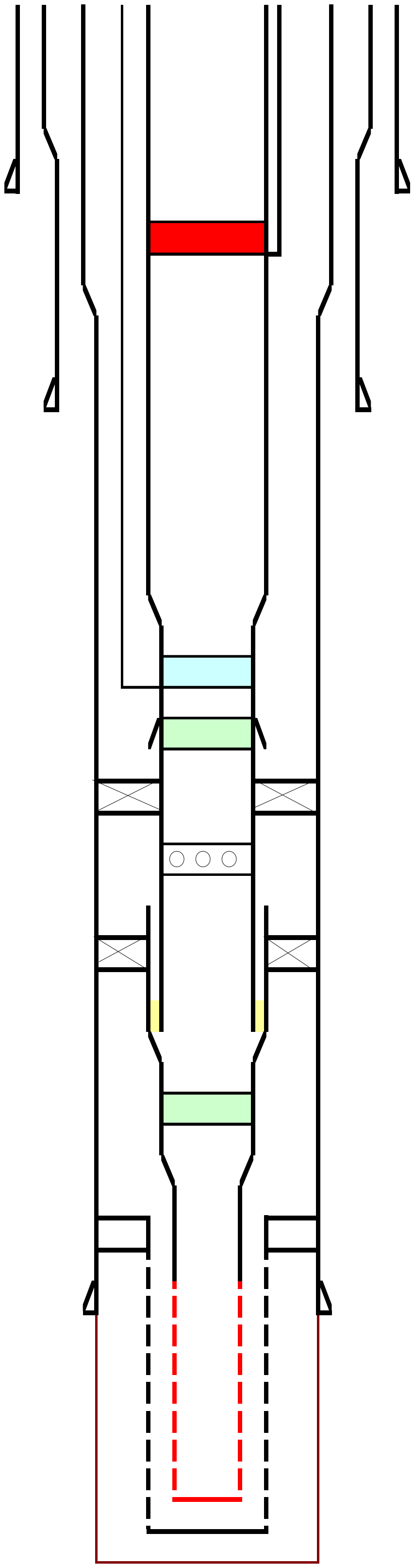
2.1. Existing wells construction summary

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

Table 2-2: General well construction characteristics

Attribute	Value/Data
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
DFE	152.5ft (46.5m) (Drilling Rig)
Water depth	395ft [120.4m]
Number of wells	5 existing, 3 slots available.
Top reservoir (ft TVDSS)	Approximately 8300ft [2529.84m]

The five Goldeneye wells are of similar construction. Figure 2-1, provides a simplified schematic of one of the existing wells (GYA01).



	AHD (ft)	TVD (ft)
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

Note: Not to scale

The upper and lower completion of the current wells comprises of:

- Upper Completion

  SSSV 5.875" [149mm], 7" tubing 6.184", 5" tubing 4.67", PDG 4.576", Polished Bore Receptacle (PBR) 4.577", Packer 4.65"
- Lower Completion

  Formation Isolation Valve (FIV) 2.94", Screens 3.548", X-over 3.515"

The maximum well deviation (measurement of a borehole's departure from the vertical) is shown in Table 2-3 below:

Table 2-3: Well deviation of the existing wells

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

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) are shown in Figure 2-2. GYA02S1 is the sidetrack of well GYA02

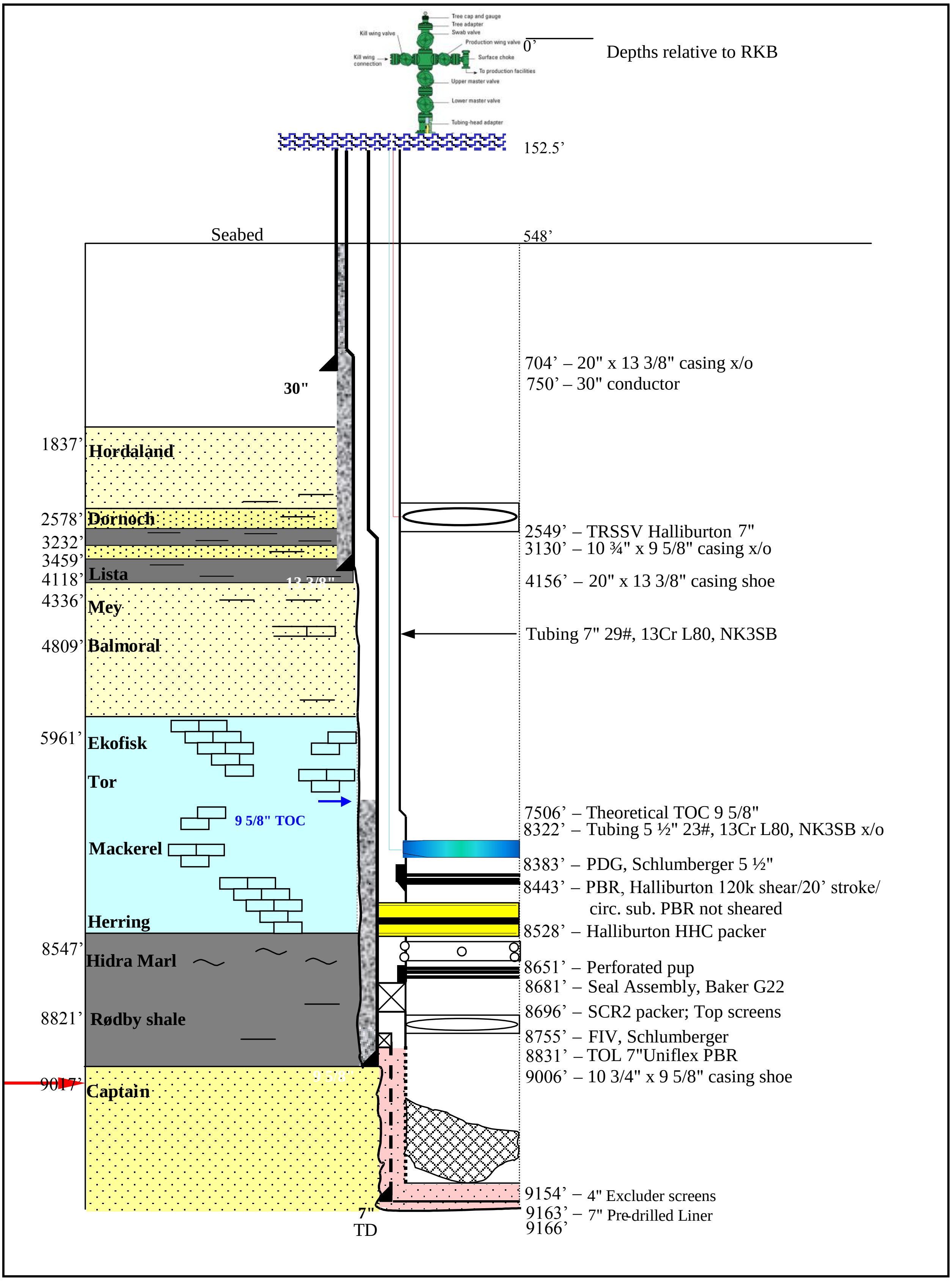


Figure 2-2: GYA01 well schematic including formations

2.1.1. Lower Completion in Hole Tally (GYA01)

A list of equipment installed in the lower completion (in hole tally) is provided in Table 2-4.

Table 2-4: GYA01 Lower Completion in-hole tally

Description	OD	ID	Length	Cum. Length	Depth
SC-2R Packer, Size 96B-60, 7-5/8" 29.7 lb/ft Hunting Boss Box Down, 13 Cr	8.313	6.000	5.79	5.79	8,696.09
Upper Extension, 7-5/8" 29.7 lb/ft Hunting Boss Pin x 7-5/8" 8 TPI Acme Pin, 13 Cr	8.124	6.870	3.65	9.44	8,701.88
Model S GP Sliding Sleeve, 7-5/8" 8 TPI Acme Box 7" 26 lb/ft Hunting Seal Lock HT Box, 13 Cr	7.810	6.000	3.75	13.19	8,705.53
Lower Extension, 7" 26 lb/ft Hunting Seal Lock HT Box x Pin, 13 Cr	7.000	6.290	15.70	28.89	8,709.28
Model A Indicating Coupling (Circulating Position), 7" 26 lb/ft Hunting Seal Lock HT Box x Box, 13 Cr	7.640	5.500	1.12	30.01	8,724.98
Spacer Extension, 7" 26 lb/ft Hunting Seal Lock HT Pin x Pin, 13 Cr	7.000	6.270	1.72	31.73	8,726.10
Model A Indicating Coupling (Honed), 7" 26 lb/ft Hunting Seal Lock HT Box x Box, 13 Cr	7.630	6.266	1.12	32.85	8,727.82
Indicating Extension, 7" 26 lb/ft Hunting Seal Lock HT Pin x Pin, 13 Cr	7.040	6.275	6.85	39.70	8,728.94
Quick Connect (Upper Half), 7" 29 lb/ft Hunting Seal Lock HT Box x QC Upper, 13 Cr	7.685	6.000	1.99	41.69	8,735.79
Quick Connect (Lower Half), 7" QC Lower x 7" 29 lb/ft Hunting Seal Lock HT Pin, 13 Cr	7.800	6.000	1.67	43.36	8,737.78
Pup Joint, 7" 29 lb/ft Hunting Seal Lock HT Box x Pin, 13 Cr	7.690	6.185	5.00	48.36	8,739.45
Casing Sub, 7" 29 lb/ft Hunting Seal Lock HT Box x 5" 15 lb/ft Vam Top HT Pin, 13 Cr	7.655	4.350	0.90	49.26	8,744.45
Pup Joint, 5" 15 lb/ft Vam Top HT Box x Pin, 13 Cr	5.585	4.400	5.35	54.61	8,745.35
Pup Joint, 5" 15 lb/ft Vam Top HT Box x Pin, 13 Cr	5.605	4.404	4.80	59.41	8,750.70
Schlumberger FIV, 5" 15lb/ft Vam Top HT Box x Pin, 13 Cr	5.504	2.945	19.52	78.93	8,755.50
Pup Joint, 5" 15 lb/ft Vam Top HT Box x Pin, 13 Cr	5.523	4.394	5.15	84.08	8,775.02
Pup Joint, 5" 15 lb/ft Vam Top HT Box x Pin, 13 Cr	5.600	4.395	5.38	89.46	8,780.17
Casing Sub, 5" 15 lb/ft Vam Top HT Box x 4" 9.5 lb/ft New Vam Box x Pin, 13 Cr	5.480	3.515	1.21	90.67	8,785.55
Pup Joint, 4" 9.5 lb/ft New Vam Box x Pin, 13 Cr	4.378	3.548	7.87	98.54	8,786.76
Blank Pipe, 4" 9.5 lb/ft New Vam Box x Pin, 13 Cr	4.378	3.548	39.17	137.71	8,794.63
Blank Pipe, 4" 9.5 lb/ft New Vam Box x Pin, 13 Cr	4.378	3.548	38.45	176.16	8,833.80
Blank Pipe, 4" 9.5 lb/ft New Vam Box x Pin w/ 5.5" OD Fins, 13 Cr	5.500	3.548	40.14	216.30	8,872.25
Blank Pipe, 4" 9.5 lb/ft New Vam Box x Pin w/ 5.5" OD Fins, 13 Cr	5.500	3.548	40.01	256.31	8,912.39
Excluder2000 Screen (medium), 4" 9.5 lb/ft New Vam Box x Pin w/ 5.75" Econo-liser, 13 Cr	5.750	3.548	40.14	296.45	8,952.40
Excluder2000 Screen (medium), 4" 9.5 lb/ft New Vam Box x Pin w/ 5.75" Econo-liser, 13 Cr	5.750	3.548	39.85	336.30	8,992.54
Excluder2000 Screen (medium), 4" 9.5 lb/ft New Vam Box x Pin w/ 5.75" Econo-liser, 13 Cr	5.750	3.548	40.15	376.45	9,032.39
Excluder2000 Screen (medium), 4" 9.5 lb/ft New Vam Box x Pin w/ 5.75" Econo-liser, 13 Cr	5.750	3.548	40.14	416.59	9,072.54
Excluder2000 Screen (medium), 4" 9.5 lb/ft New Vam Box x Pin w/ 5.75" Econo-liser, 13 Cr	5.750	3.548	40.13	456.72	9,112.68
Bullnose, 4" 9.5 lb/ft New Vam Box Up, 13 Cr	4.355	N/A	0.80	457.52	9,152.81
				Depth to Bottom of Bull Nose	**9,153.61**

2.1.2. Existing wells status

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.

Safety valve control line integrity issues were noted on wells GYA01 and GYA03 in 2012 and therefore an intervention campaign was carried out and suspension plugs were set in all the wells (Figure 2-3). Maintenance was also performed on some tree valves.

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 2-5.

Table 2-5: Suspension plugs – Setting depths

	GYA01	GYA02	GYA03	GYA04	GYA05
Suspended	Nov 2012	May 2012	April 2012	May 2012	Feb 2013
Plug 01	139 ft	124 ft	134 ft	118 ft	148 ft
Plug 02	2669 ft	10362 ft	2618 ft	2976 ft	7731 ft
Plug 03	8595 ft		9017 ft		
	Gas migration through SSSV control line		Gas migration through SSSV control line		

As discussed in the Well Integrity Assessment Report (Key Knowledge Deliverable 11.113) (5) none of the wells are subject to major integrity issues.

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.

Well integrity tests (WITS) are carried out on an annual basis. All well integrity information is captured and stored in eWIMS (global electronic database that captures well integrity data for Shell operated wells) under the responsibility of a Well Integrity Focal Point. Additionally, the St. Fergus control room monitors annulus pressure gauges on all wells continuously, with alarms at predetermined levels.

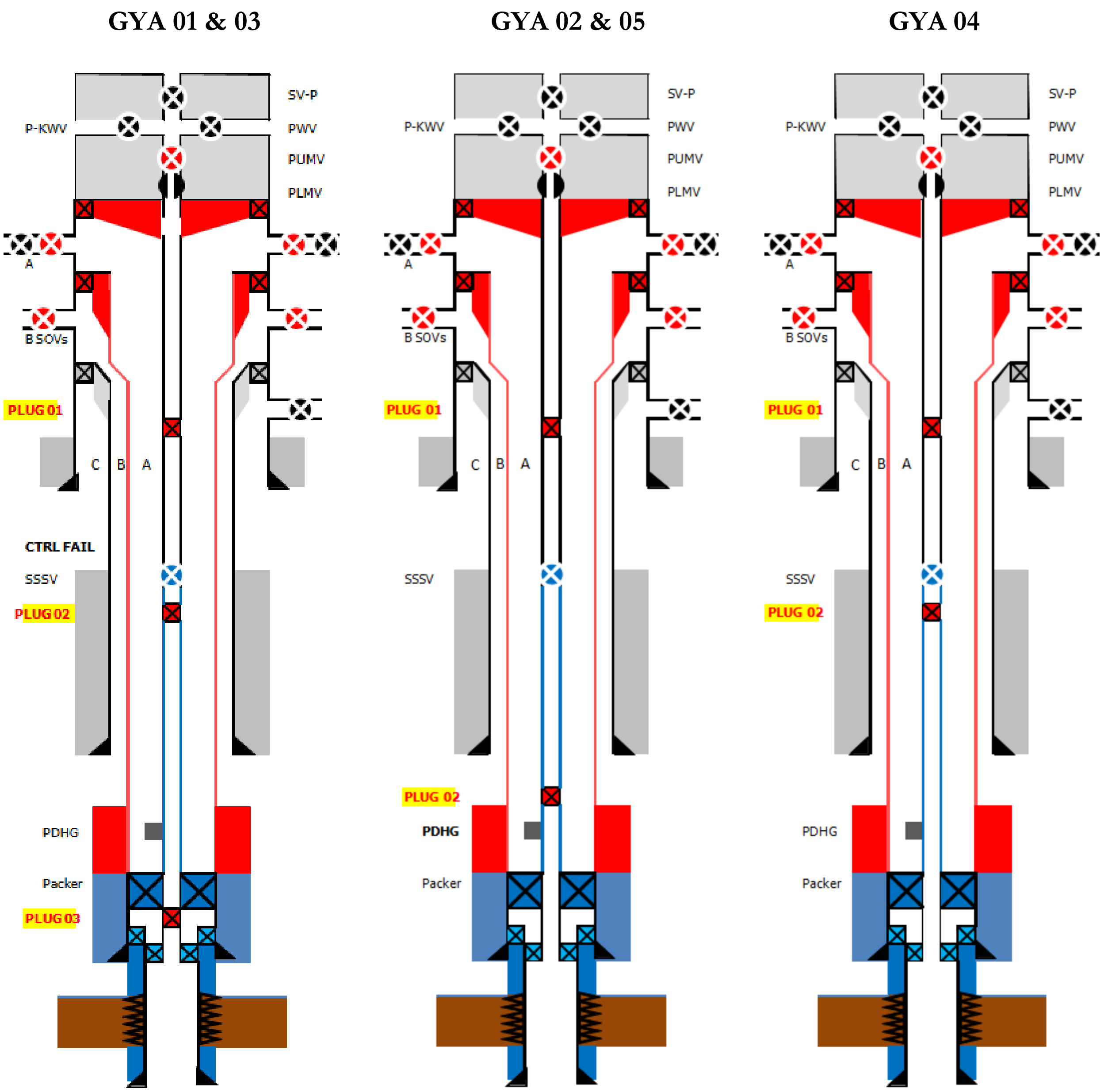


Figure 2-3: Wells Suspension Status

2.2. Peterhead – Goldeneye CCS Information

2.2.1. General Information

The Table 2-6 below summarises key metadata from Goldeneye platform and reservoir.

Table 2-6: Goldeneye General Information

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

2.2.2. Goldeneye field - Geology

The injection reservoir is the Captain Sandstone (Figure 2-4). Vertical containment is provided by the 300 m thick primary storage seal, a package including part of the Upper Valhall Formation, Rødby Formation, Hidra Formation and the Plenus Marl Bed.

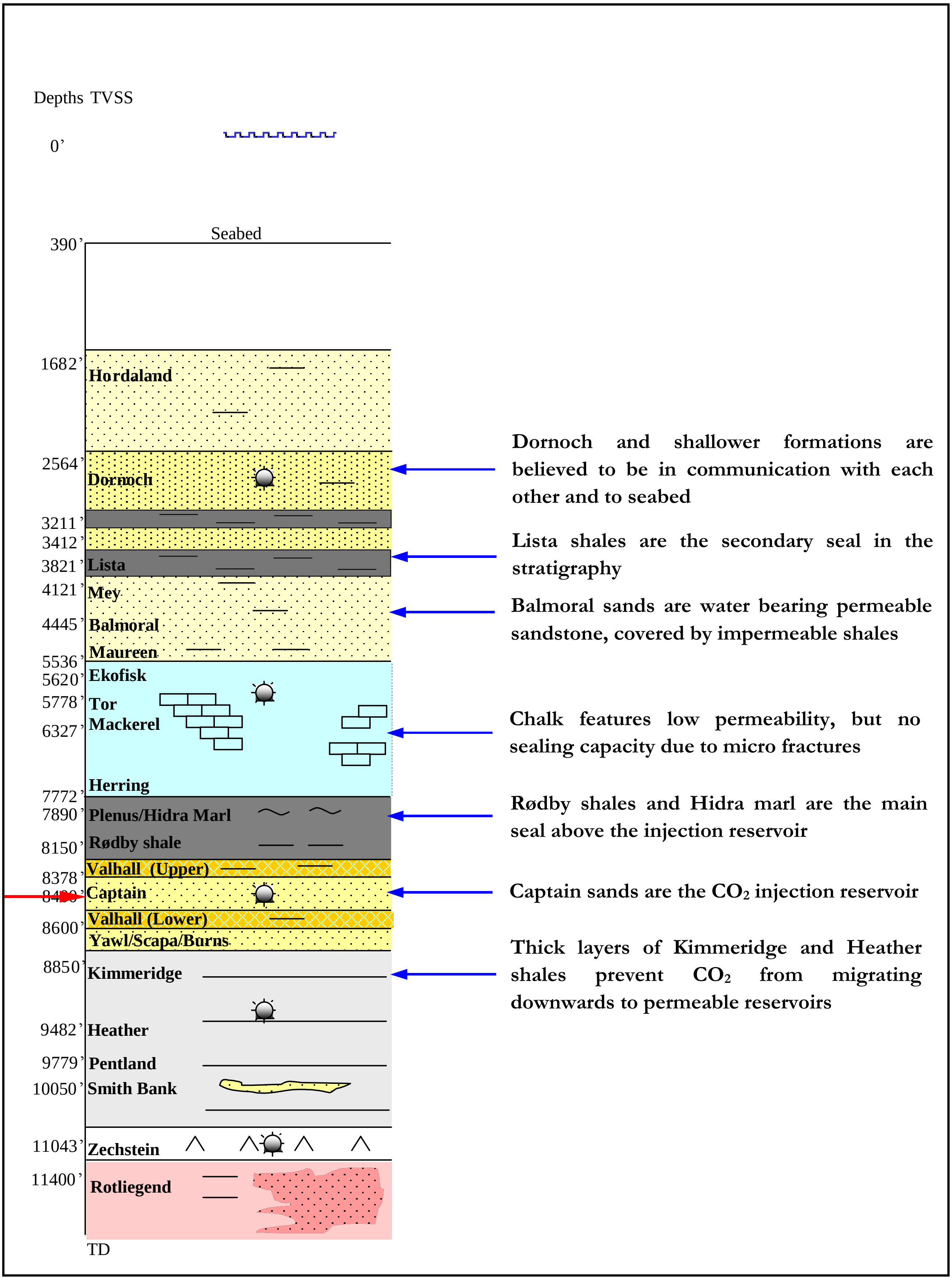


Figure 2-4: Main Stratigraphy for Goldeneye area, average depths of formation tops

2.2.3. Reservoir Characteristics

The reservoir characteristics are summarised in Table 2-7 below:

Table 2-7: Reservoir Characteristics

Attribute	Value/Data
Type	Sandstone Captain formation
Formation temperature	Approximately 83°C @ 8400 ft [2560m] TVDSS Lower temperature to be encountered during injection
Formation Water	Present in the bottom of the well.
	Water will be initially at the sand face. Evidence of water from downhole pressure gauges in GYA03.
	Formation water around the wellbore will reduce significantly after 6 to 9 months of continuous CO_2 injection. However, water might return after long periods of no injection or insufficient cumulative volume.
Average Reservoir (Captain D) Porosity and Permeability	~25% porosity 790 mD permeability The Captain D is a clean sandstone with very high Net to Gross Captain D presented an excellent connectivity during the hydrocarbon production phase.
Pressure Regime	(The pressure regime is given as an indication for general well/completion design selection. It will be re-calculated before any well operation and before working over the wells). An active aquifer supports the field. All the wells are currently shut in due to water breakthrough and isolated with deep and shallow downhole plugs.
	Original Reservoir Pressure ~ 3815 psia [263bara] @datum 8400 ft TVDss Minimum Reservoir pressure after depletion ~ 2100 psia @ datum Current pressure is ~2650 psia (@ end of December 2013) @ datum
	Minimum expected reservoir pressure before CO_2 injection (approximately Year 2019): 2650 psia, Pressure Gradient Range - 0.319 psi/ft (see note below)
	Maximum expected reservoir pressure after 10 million tonne of CO_2– (~Year 2031) 3450 psia, Pressure Gradient: 0.416 psi/ft Information is of enough quality for this analysis/report on WFS. Different section of tubing (4 ½" and 3 ½") to be installed in each well will depend on this information.

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

2.2.4. Fluids Characteristics

The fluids characteristics are summarised in Table 2-8 below:

Table 2-8: Fluids characteristics

<table>
<tr><th>Attribute</th><th>Data</th></tr>
<tr><td>CO_2</td><td>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): ~56000 ppm (52000 ppm – Sodium Chloride - 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.</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>

2.2.5. CO_2 Injection Conditions

The CO_2 injection conditions are summarised in Table 2-9 and Table 2-10 below:

Table 2-9: CO_2 injection rates

Attribute	Description
Total CO_2 available	The project requires to inject up to 15 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 15 years for up to 15 million tonnes (including downtime).
CO_2 fluctuation	For the injection years, the turndown case will be 65%. All the surface equipment should be design to minimum turndown of 65%. The reference case is to operate the capture plant at based load (i.e. continuous flow) during the first five years on injection. 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 hours to 4 hours of CO_2 injection depending on the operating conditions of the pipeline).

Table 2-10: CO_2 arrival temperature at the platform

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

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

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

The bottom hole temperature (BHT) will depend on the injected fluid temperature and the rate of injection, the expected BHT is between 23°C to 35 °C. These steady state injection characteristics are summarised in Table 2-11 below.

Table 2-11: Steady state injection characteristics

Attribute	Description
Wellhead pressure (WHP)	Minimum: 50 bara It can be optimised during cold months considering the arrival temperature of the CO_2 to the platform. CO_2 will be injected in a single phase with wellhead pressures kept above the saturation line. Maximum: 120 bara This is the maximum arrival pressure to the platform limited by the offshore pipeline
Manifold CO_2 temperature (MFT)	CO_2 arrival temperature will present some minor seasonal variations. This will be similar to the seabed temperature with some variations due to CO_2 riser expansion For design purposes – the minimum temperature is estimated at 2.3°C, the maximum is 10.1°C For operational purposes the expected fluctuation is between 5.3°C to 8°C
Wellhead CO_2 temperature (FWHT)	There will be some JT effect across the choke being more pronounced at lower wellhead injection pressure The minimum temperature is 0.5°C at 50 bara injection pressure The maximum temperature is 10.1°C at 120 bara injection pressure
Bottom Hole temperature (BHT)	The bottom hole temperature (BHT) will depend on the injected fluid temperature and the rate of injection. There will be reduction of temperature around the injectors due to cold CO_2 injection. For the CCP rates in the Peterhead project, the expected BHT is between 23°C to 35 °C. Reference Case 23°C bottom hole injection temperature

2.2.6. 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 shown in Table 2-12 as follows:

Table 2-12: Results of transient calculations – design case (base oil in annulus)

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

Strict operational procedures need to be implemented and adopted by the Goldeneye Well Operations Group to avoid extreme cooling of the well components due to temperature limitation of the well components. These are detailed in the Well Operation Guidelines (Key Knowledge Deliverable 11.104) (6).

Frequent opening-up and closing-in events should 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.

2.2.7. Closed-in Tubing Head Pressure

The closed in tubing head pressure (CITHP) will depend on the reservoir pressure (or downhole pressure) and the fluid inside the tubing. Two extreme cases exist: Well filled with CO_2 and well filled with CH_4.

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 at the end of the 15 million tonnes injection period, the CITHP is relatively low (approximately 50 bara) at the maximum predicted reservoir pressure of around 3800 psia (Figure 2-5).

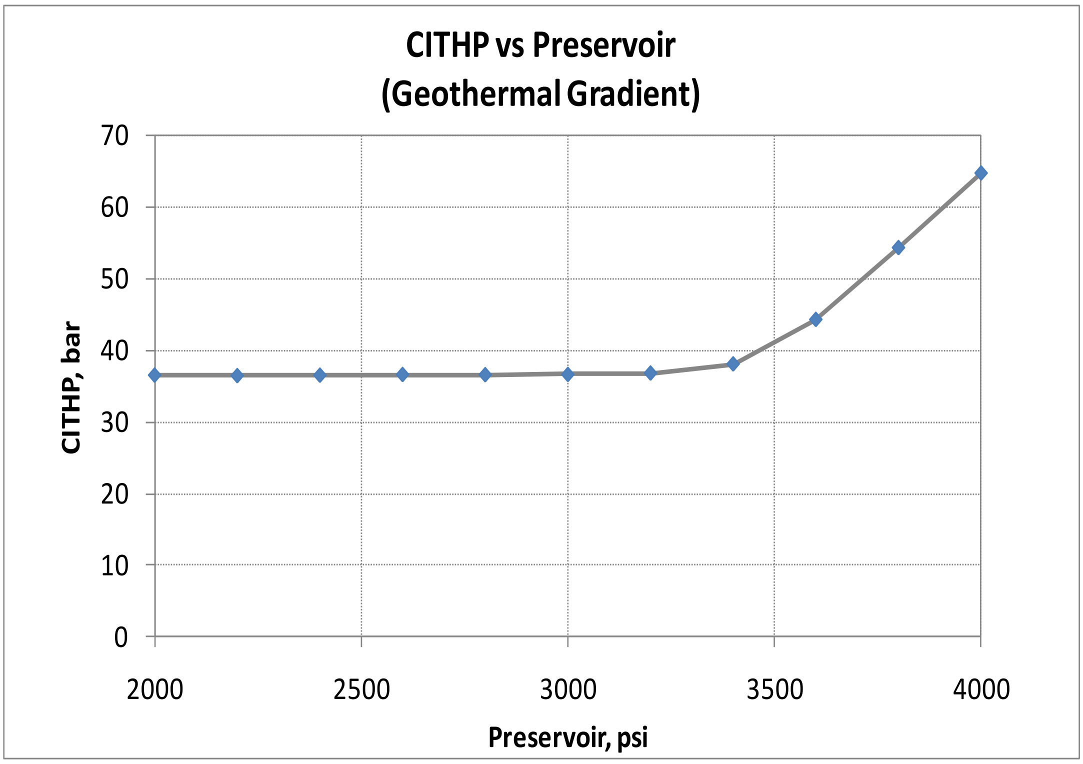


Figure 2-5: CITHP for a well filled with CO_2

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

In case the well is full of hydrocarbon gas then the predicted CITHP at the same reservoir pressure (3800 psia) would be in the order of 220 bara (assuming methane filling the tubing), see Figure 2-6.

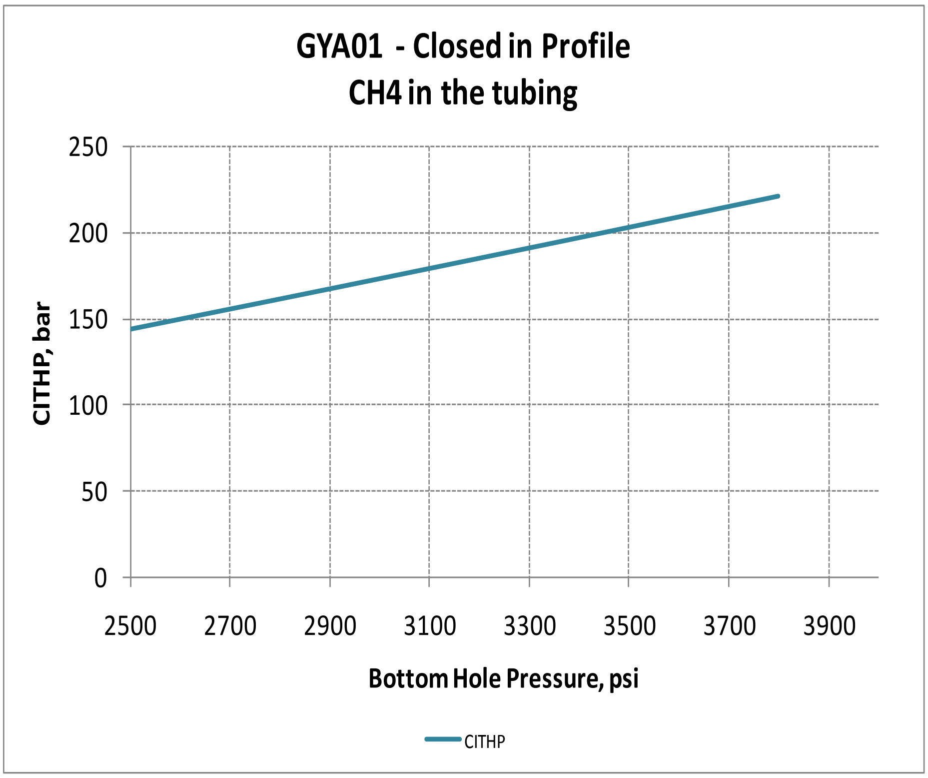
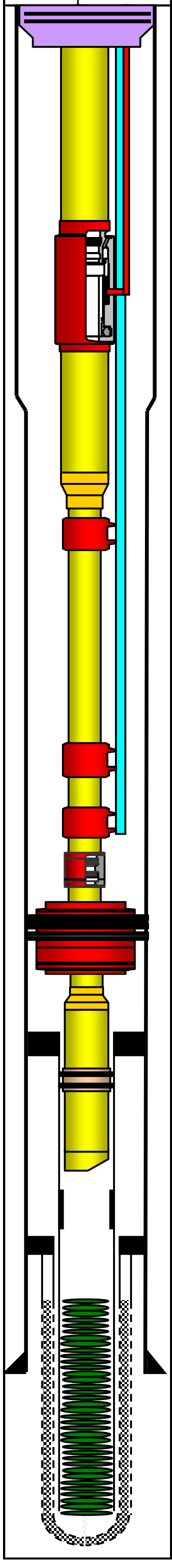


Figure 2-6: CITHP for a well with Methane in the tubing

2.2.8. Proposed Completion Well Design (Schematic)

The proposed completion schematic is shown in Figure 2-7 below.



GYA 01 Proposed	Depth MD (ft)	Description of Item	ID (Inches)
	79	Tubing Hanger	
		4 1/2" 13.5# Vam Top HT Tubing S13Cr	3.920
		Control Line protectors	
		1/4" SSSV Control Line (low pour point fluid) 11x11mm	
	2550	4 1/2" SSSV (non self equalising)	3.812
	3130	Casing XO 10 3/4" x 9 5/8"	
		4-1/2" 13.5# Vam top HT Tubing 13Cr	
	6700	XO 4 1/2" 13.5# x 3 1/2" 10.2#	
		3 1/2" 10.2# Vam Top Tubing 13Cr	2.922
	6750	3 1/2" PDGM for PDG (tubing gauge)	
		Proposed 1/4" Hybrid gauge line (electric + FO) 11x11mm	
	8300	3 1/2" PDGM for PDG (tubing gauge)	
		3 1/2" 10.2# Vam Top Tubing 13Cr	
	8550	3 1/2" PDGM for PDG (tubing & annulus gauge)	
		3 1/2" 10.2# Vam Top Tubing 13Cr	
		3-1/2" Circulating Device	
	8596	9 5/8" x 3 1/2" Packer (cut to release)	2.940
		3 1/2" 10.2# Vam Top Tubing 13Cr	
		XO 3 1/2" 10.2# Vam Top Tubing X G22 dummy seal unit	
	8696	Baker SC-2R packer/screen hanger 13Cr (existing)	
		G22 dummy seal units	
		4 1/2" WEG	
	8755	Schlumberger FIV (existing)	2.940
	8952	Top of 4.00" Screens (existing)	3.548

Figure 2-7: Proposed Completion Schematic – Well GYA01

3. Completion Design & Components

The objective of the workover is to provide a well capable of maintaining integrity under CO_2 injection and to manage the phase behaviour of the CO_2 and limiting the effects of Joule Thomson (JT) cooling associated with CO_2.

The existing Polished Bore Receptacle (PBR) will be replaced as there is concern around its integrity under CO_2 injection. This is due to extreme low CO_2 injection temperatures modelled if the existing completion string (7" x 5 ½" [178mm x 140mm] nominal diameter) is utilised for injection purposes. This cooling effect will lead to contracting of the tubing and create sufficient force to shear the 120,000 lb [54,431kg] rated shear ring in the PBR. Ensuing movement of the PBR mandrel due to variations in downhole pressure and temperature will cause the PBR seals to fail. This will allow CO_2 to enter the "A" Annulus and mix with existing water based completion brine resulting in the formation of Carbonic Acid. This will have an immediate and significant threat to the integrity of the 9 5/8" L80 casing by corrosion.

Another concern around utilising the existing Goldeneye wells in CO_2 injection service is the presence of a perforated pup joint in the tubing below the production packer which can accelerate corrosion of the 9 5/8" production casing (see Figure 2-2) due to stagnant water between the existing completion string and the production casing.

The concerns around using the existing completion for CO_2 injection are detailed in the Conceptual Completions and Well Intervention Design Report (1).

The potential low temperatures pose restrictions in terms of well design including special well materials, fluids, equipment and procedures. To avoid the low temperatures, the CO_2 stream will be kept in dense phase by increasing the required injection wellhead (WH) pressure above the saturation line (liquid at the WH). The resultant WH temperature will be in the design range for the wells and operations. The required extra pressure drop in the well can be achieved by increasing friction or back pressure. Decreasing the tubing size leads to an increase of the velocity for a particular injection rate which in turn increases the frictional force in the tubing resulting in an increase of the WH pressure. With an appropriate change in the upper completion the WH pressure may be increased to the extent that it lies above the saturation line. As such, the minimum WH pressure in the well is determined by the requirement to operate the well in single phase.

Another consideration which defines the technical specification is the potential low temperatures which will be encountered under a highly unlikely isenthalpic expansion of CO_2 to atmospheric pressure. The CO_2 phase behaviour is described by Figure 3-1. It is however important to highlight that these scenarios are highly unlikely.

The CO_2 phase behaviour is described by the diagram below.

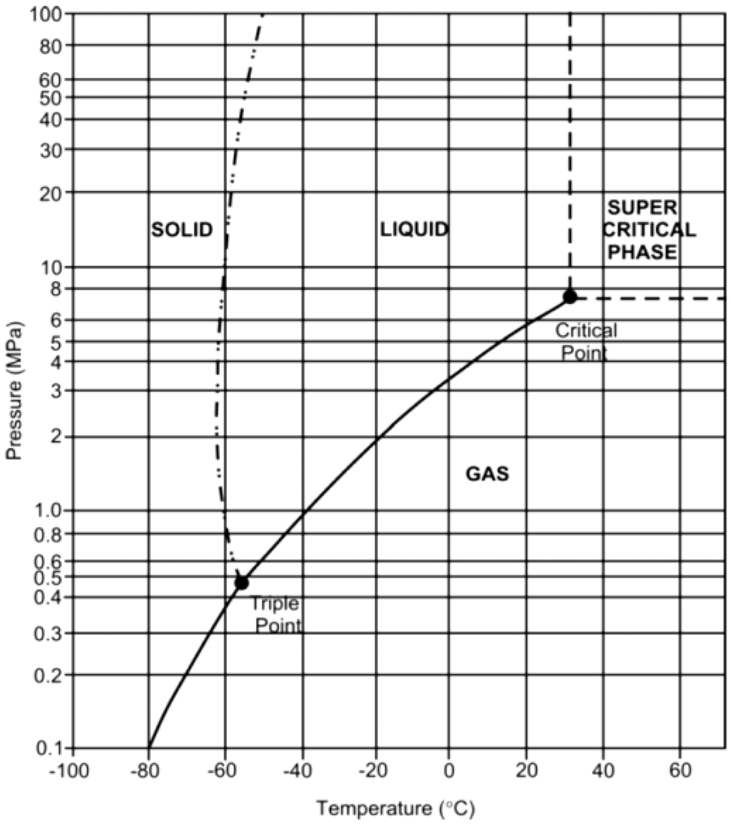


Figure 3-1: CO_2 phase behaviour diagram (7)

The requirement to workover the upper completion provides opportunity to optimise the well design to be best suited for CO_2 injection during the life of the project and future well decommissioning. The tubing geometry, materials, seals and fluids have all been evaluated and best fit components and technologies designed into the detailed completion and well intervention design, see proposed completion schematic Figure 2-7.

The workovers also provide the opportunity to evaluate the cement behind the production casing (cement bond log, CBL) and to carry out casing analysis to confirm the suitability for placing the new production packer. This also provides an opportunity to place the new production packer deeper in the well opposite the Hidra formation which forms part of the primary seal. This also facilitates future abandonment of the wells as highlighted in the Abandonment Concept for Injection Wells (Key Knowledge Deliverable 11.100) (8).

The new completion also acts as a means to convey additional downhole instrumentation which allows for the optimisation of the in-well surveillance.

Suitable annulus fluid and elastomers will also be used as part of the new completion design thereby enabling the well to operate and maintain integrity under CO_2 injection service for the duration of the project.

3.1. Material/Corrosion

Key well construction materials and their performance in the presence of CO_2 are discussed in Table 3-1 below.

Table 3-1: Well Construction Materials

Material	Properties
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. In carbon steel tubulars, CO_2 corrosion is mitigated by control of the water content 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 elastomer to be in contact with CO_2 needs to be checked for its compatibility.
Cement	Degradation rates are proportional to temperature, pressure and the square root of time. From literature, estimates for cement degradation vary from 0.05 m to 12.36 m in 10,000 years. Goldeneye conditions are predicted to be approximately 2m in 10,000 years.

3.2. Casing, Conductor and Cement

The base case plan for the workovers involves utilising the existing casing strings and conductors. The casing strings were cemented in place with a Portland class G based cement slurry. These items of the well have been evaluated for their suitability for use in CO_2 injection without any major concerns. A summary of the evaluation process is provided in the Conceptual Completion and Well Intervention Design Endorsement Report (1). For completeness the following information has been included here with some recent updates from the detailed well design.

3.2.1. 30" Conductor

The 30" conductor was driven 200 ft [61m] into the seabed. The 20" [508mm] surface casing was cemented to seabed, but not cemented to surface. Hence the 30" and 20" pipes are freestanding and independent of one another. 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. It follows that no load transfer to the conductor is expected.

The 30" conductor will not be in direct contact with CO_2 and no significant cooling of the carbon steel conductor is expected.

An additional Pulsed Eddie Current (PEC) survey was carried out in 2014. It is also planned to carry out periodic Remote Operated Vehicle (ROV) and PEC surveys of the conductor.

3.2.2. 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 4150 ft. The 20" 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" 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 and included a negative wellhead growth calculation to provide an indication of level of movement expected in the casing strings as the well is cooled down during CO_2 injection. Periodic PEC corrosion surveys have been run on both the conductor and the surface casing. A recent survey was carried out in 2014. Periodic surveys will continue in the future.

It has been concluded that 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.

3.2.3. 10 ¾ x 9 5/8" Production Casing

The second casing string or 10 ¾" x 9 5/8" taper production casing was set at the bottom of the Rødby formation. This casing was cemented to approximately 1500 ft AHD 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 negligible 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 or CO_2 during the injection phase. The new S13Cr and 13Cr tubing will prevent the CO_2 contacting this casing string.

Underneath the existing production packer, a section of production casing has been exposed for the period of approximately 6 years to the hydrocarbon production environment (natural gas with 0.3% CO_2). It is possible that this has led to some corrosion of the casing. As an estimate of maximum corrosion, assuming wetting for the full 6 years of field production, the corrosion loss is estimated to be of the order of 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 is probably less and of therefore of little significance.

The same section of the carbon steel production casing (underneath the production packer), will 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/yr. it would take a little more than 1 year of wet exposure to corrode through the ½" thickness of the casing. This implies 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 axial 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 Rødby also present adequate sealing characteristics.

In the existing well completion (see Figure 2-2), a perforated pup joint is present between the production packer and the top of the screen hanger; this section creates a stagnant volume between the tubing and the production casing. It is planned to remove the perforated tubing section during the workover operations to give more protection to the casing. This is explained further in the section on well construction (Section 4).

Due to injection of cold CO_2, the load cases are driven towards tensile loading due to thermal contraction. Normal CS shows adequate physical properties down to 0°C. For lower temperatures, carbon steel requires to be impact tested. Available certificates that support the quality of the installed production casing were analysed and Charpy values demonstrating adequate toughness down to -40°C were confirmed.

3.2.4. Cement

The primary cement sheath of the production casing is a barrier to contain the CO_2 downhole in the well. The cement used in the slurry is normal Portland class G cement. The theoretical top of the cement (TOC) in the B-annulus between 9 5/8" production casing and the 10 ¾" hole has been estimated for all five wells during the cementing operations. The cement column from the 9 5/8" casing shoe to the theoretical TOC is calculated at 1,500 ft. along-hole depth (AHD) above the shoe, which is well above the formation seals of the reservoir. Cement evaluation logs were not run during the drilling phase of the wells, but are planned 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 ft and 1,351 ft. AHD depending on the well. The cement is covering the primary seal formations (Rødby and Hidra) in all five wells up into the Chalk formation. There 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.

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 and case studies related to the potential degradation of Portland based cements when exposed to high CO_2 environments. Degradation rates have been found to be proportional to temperature, pressure and the square root of time. From literature, estimates for cement degradation vary from 0.05 m to 12.36 m in 10,000 years. For Goldeneye conditions it is estimated to be approximately 2 m in 10,000 years.

Diana software, a specialist mechanical cement model was 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 indicated 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.

3.3. Wellhead, Tree & Tubing hanger

The existing Goldeneye Christmas tree and wellhead is suited to CO_2 injection for the specified steady state operating parameters. The system was primarily designed for gas production, which makes it a good candidate for CO_2 injection. A feasibility study was carried out to evaluate the suitability of the existing system for CO_2 injection. The three main areas of concern are ED (Explosive Decompression) resistance, corrosion resistance and low temperature performance.

ED (Explosive Decompression) Resistance; The Goldeneye Christmas tree provided good ED resistance in gas production service. The elastomers, which could be susceptible, are in the annulus regions, which would require breakdown of the primary seals for them to become exposed to CO_2. If the elastomers were exposed to an ED environment, they would show signs of ED damage on the side exposed to the gas, however as they are constrained in the groove severe damage does not occur until the seal is removed allowing it to expand and tear as gas escapes from inside the elastomer.

Corrosion resistance; The existing Goldeneye Christmas tree and wellhead system is resistant to dry CO_2. However if the CO_2 becomes wet, it can form carbonic acid, which will corrode carbon steel and depending upon the Ph. level may corrode stainless steel.

Low temperature performance; The Goldeneye Christmas tree is designed for API 6A temperature class U (-18°C to 121°C). The 7.00" Tubing Hanger is designed for temperature class S, T, U, V (-18°C to 121°C). The10-3/4" Casing Hanger is designed for temperature class P-U (-18°C to 82°C). The 18-3/4" 3 Stage compact housing is designed for U (-18°C to 121°C). Notably the elastomers reviewed for ED resistance have a greater temperature range than those of the metallic components, as low as –50°C [-58°F] for some component parts.

As previously stated the Goldeneye Christmas tree and wellhead is suited to CO_2 injection for the specified steady state operating parameters for temperatures down to -18°C (0°F). However an analysis of the material specifications revealed that the same metallurgy is utilised on lower temperature rated equipment (API 6A, temperature class 'K') with additional (lower temperature) impact tests.

Due to low transient temperatures (in the order of -20°C in the CO_2, see Figure 3-2) during opening and closing of the wells and even lower temperatures which might be encountered in highly unlikely CO_2 release scenarios, surface trees and tubing hangers will require to be changed to low temperature compatible equipment (API 6A temperature class 'K'). These well items will be manufactured and installed as part of the workover operations.

Under uncontrolled leaks, the temperature of the CO_2 might get very cold (metal temperatures estimated at the triple point -56°C and jet temperatures of around -80°C). The Christmas tree and the tubing hanger can be changed to accommodate this highly unlikely event. However, some well elements such as the wellhead system and casing hangers cannot be changed. Detailed thermal simulations of the wellhead/Christmas tree system were carried out to evaluate the extension of the low temperature during highly unlikely leak scenarios in order to evaluate the suitability of these components.

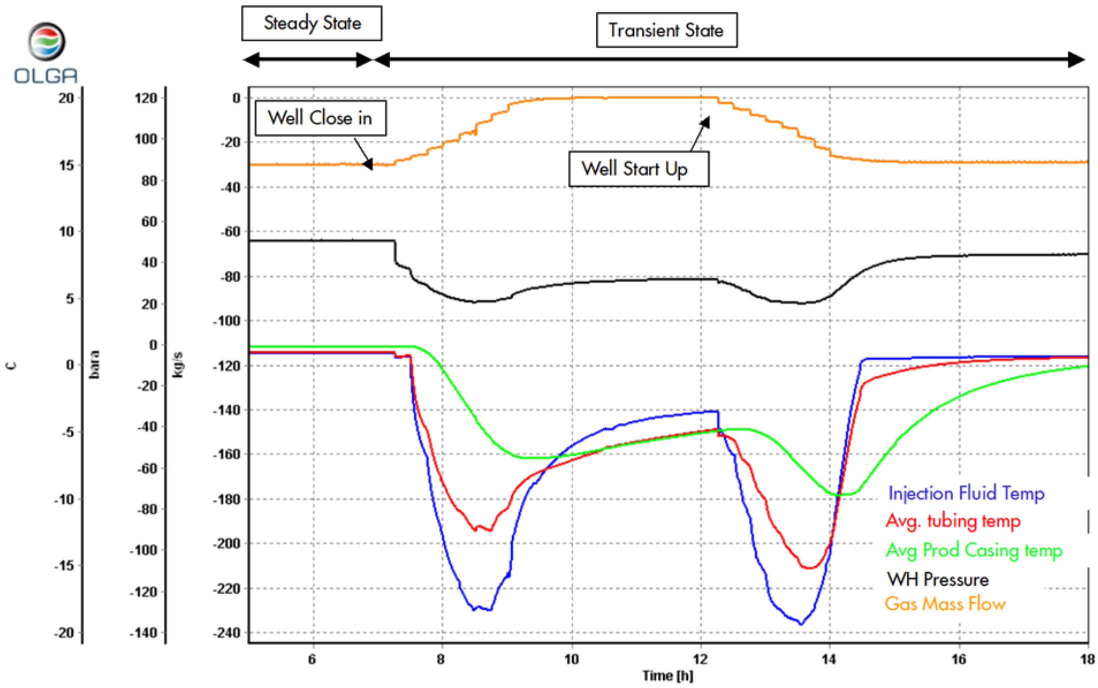


Figure 3-2: Well Component Temperature (top well section during transient conditions)

Computational Fluid Dynamic (CFD) modelling was carried out based on predicted temperatures results from OLGA simulations, see Figure 3-3. The CFD models showed that for small weeps and seeps and releases of up to 28 mm diameter there is no significant cooling at the wellhead. For larger releases i.e. 50 mm in diameter modelling revealed that components of the wellhead system will see an excursion below the design rating. However there is no credible scenario leading to a continuous release of CO_2 from a leak point of such a size. Containment will be achieved via one of the tree valves.

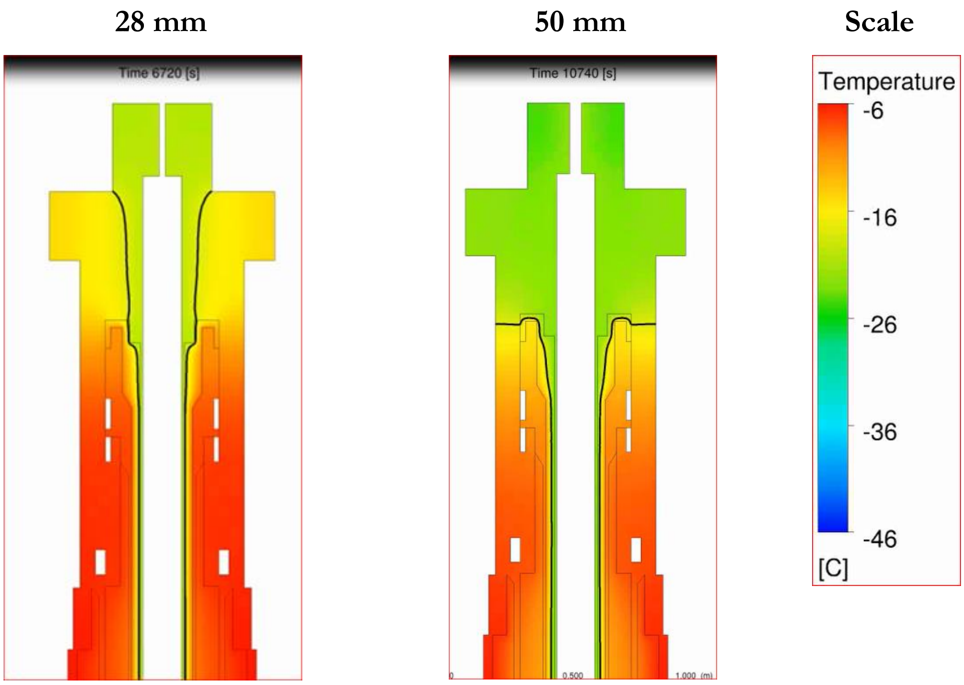


Figure 3-3: Computational Fluid Dynamic (CFD) analysis of wellhead system

A number of workshops were conducted to understand the effects the reduced temperatures would have on the wellhead/tree system, followed by engagement with vendors to share the project requirements and issue statements of requirements (SOR) allowing for expert input. The work to date has led to the decision to replace existing components with lower temperature rated alternatives providing an opportunity for optimisation.

Instead of retaining the existing design with a 7" tubing hanger this will be replaced with a smaller 4-1/2" design tubing hanger in line with the upper completion tubing design. The tree will be replaced with a more compact system. It also allows for integration of some key features into the existing tree design including additional metal to metal sealing systems, redundant sealing mechanisms such as double bonnet and stem seals, and reconfiguration of the tree cap seal design.

A schematic of the proposed wellhead and Christmas tree system is provided in Figure 3-5. The schematic shows the new proposed equipment stacked on the existing wellhead.

3.3.1. Proposed changes to existing wellhead and new equipment

The proposed changes include:

- Dummy hanger – to replace existing tubing hanger and provide interface with new tubing spool.
- Single stage tubing head spool housing.
- Metal sealing tubing hanger.
- Gate valves and actuators for wellhead and Christmas tree.
- Sealing technology for above spool and hangers.
- Remove and blank original 'A' annulus valves.
- Remove and blank original control line exit blocks.

The additional equipment to be installed on the existing Wellhead and new Christmas tree and are shown in Figure 3-5.

For sealing between the neck of the **dummy hanger** and the new **single stage tubing head spool** a combination of double T seals and metal seals has been selected, see Figure 3-4. The selected metal seal is a pressure energised unidirectional, straight bore seal. An initial sealing interface is created by radial interference of each seal lip when installed into the mating seal bore. Pressure acts on the unbalanced portion of each lip to produce the contact forces necessary for high pressure sealing.

In order to achieve the required temperature rating the **tubing hanger** incorporates metal sealing technology. This too is a field proven design and Shell UK has experience using this design of tubing hanger. The metal to metal seal is achieved by a combination of axial loading and a tapered interface creating contact stress at four radiused nibs. This is sufficient to create a gas tight seal. Any pressure acting on the seal increases the contact pressure on the nibs to enhance the seal performance.

There are two ports machined through the tubing hanger body. These are to accommodate continuous control line for the TRSSSV (Tubing Retrievable Sub Surface Safety Valve) and a signal cable for the permanent downhole monitoring. Both ports will be fitted with ¼" NPT (National Pipe Thread) x ¼" tube male fittings top and bottom and will incorporate plugged side outlets for testing the top and bottom fittings. The option to incorporate additional ports exists and this has yet to be finalised based on the number of control line penetrations required.

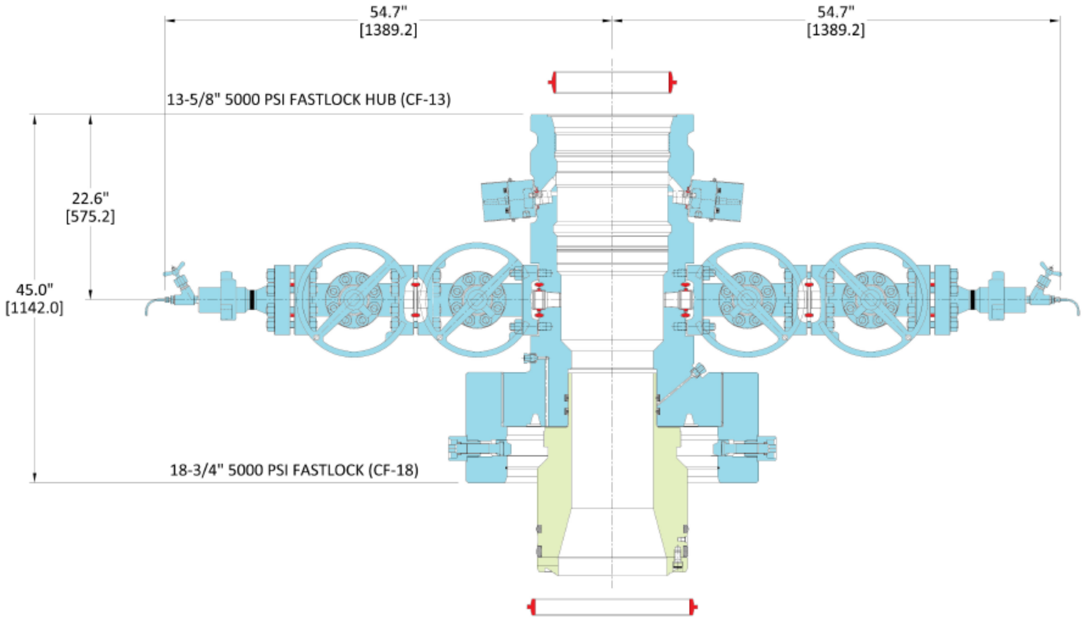


Figure 3-4: Proposed Single Stage Tubing Head Spool and Dummy Hanger

Note: Figure courtesy of Schlumberger

The proposed **Christmas Tree** incorporates 4-1/8" production wing, kill wing and top connection with a wirecutting actuator on the Upper Master Valve (UMV) and non-wirecutting actuator on the Flow Wing Valve (FWV). The assembly comprises of a single string solid block, gate valves, tree cap, instrument flange, double block and bleed needle valve, gauge, ring gaskets, studs and nuts all of which have been selected for the ability to perform in the prescribed environment. The **grease** applied to any of the valves also requires additional attention to ensure its suitability to perform at potentially reduced temperatures.

The requirement for **double bonnet and stem seals** was stipulated for enhanced reliability, again this is a field proven design and has been utilised in the North Sea.

It is also proposed to remove the standard quick union profile in the Christmas tree cap in order to remove this elastomeric seal. The quick union is a redundant feature as planned intervention rig up is designed to utilise flanged connections to reduce the potential for small releases. Also the cap to tree connection will be optimised to suit the future intervention requirements and lubricator design.

In order to withstand the potential severe low temperatures that occur under the highly unlikely event of an uncontrolled surface release of CO_2 the proposed tree and wellhead components will be clad with alloy 625, alloys such as 825 and 718 have also been proposed for some of the components.

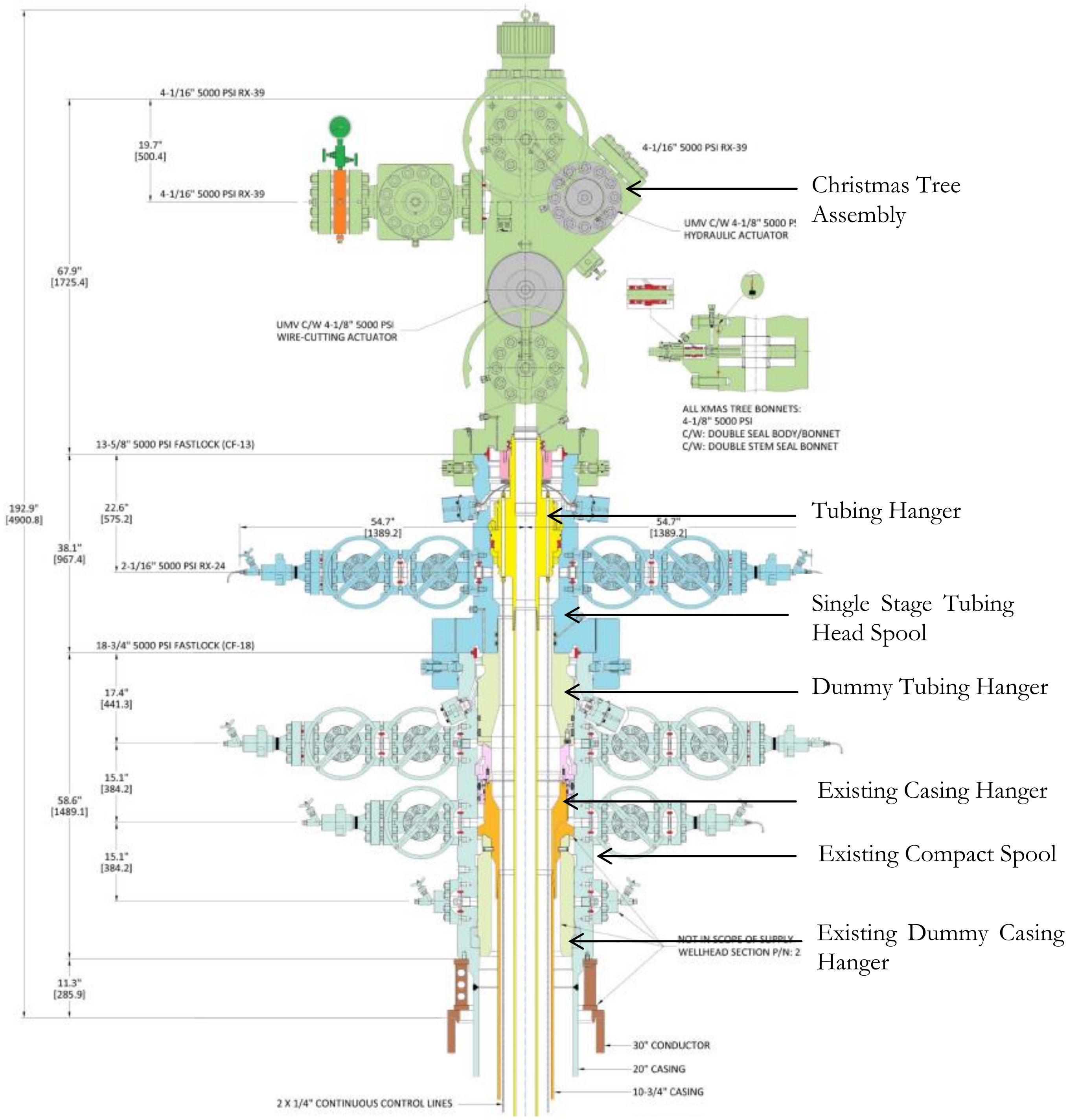


Figure 3-5: Proposed equipment on existing wellhead

Note: Figure courtesy of Schlumberger

3.4. Tubing Design, Material & Connections

Re-completion of the wells will involve replacing the 7" tubing with a smaller (diameter) size. This is in order to provide back pressure in the well, thereby keeping the CO_2 in single state during injection. As the pressure and CO_2 injection rates will vary over the duration of the project, the injection rates will be accommodated by different tubing sizes in the injection wells – initial injection period low rates with smaller tubing and later stage higher rates with larger tubing. This tubing size optimisation will be based on reservoir pressure, injection rates and power plant power generation cycles. The optimisation is reflected in the wells by the placement depth of the 4 ½" x 3 ½" crossover, leading to wells with different operating envelopes, see Table 3-3.

The completion design allows for standardisation of the top and bottom part of the upper completion. The preferred tubing size in the top of the well (from the tubing hanger to the SSSV) is 4 ½". Considering the low temperatures expected in the top of the well during transient operations it has been decided to utilise Super 13Cr (S13Cr) tubing in the top of the well (from tubing hanger to SSSV) which has enhanced physical properties in lower temperatures when compared with 13Cr, some additional testing of the S13Cr material is required and discussions are underway with the Oil Country Casing and Tubing (OCTG) supplier. There may also be a requirement to utilise 2 or 3 joints of alloy 825 tubing directly above the SSSV in order to withstand the potential extreme low temperatures that will occur at the SSSV flapper in the highly unlikely event of a significant and continuous surface release of CO_2. The involvement with the OCTG supplier on the S13Cr material properties will also be able to confirm this requirement.

Below the Subsurface Safety Valve (SSSV) 4 ½" 13Cr tubing will be utilised down to the crossover.

At the crossover the tubing will change from 4 ½" 13Cr to 3 ½" 13Cr, see Table 3-2.

There are no plans to replace the existing lower completion which consists of a gravel pack and premium screens. The lower completion tubing, screens and liner are also 13Cr material. A detailed study into the use of the existing lower completion for CO_2 injection and its suitability was conducted and no causes were found that would lead to the requirement of a lower completion workover/sidetrack. The study involved an analysis of the materials, corrosion, screen performance under reverse flow, plugging and erosion of the screens and formation. The details of this study and its findings are included in the Conceptual Completion and Well Intervention Design Endorsement Report (1). A summary of the analysis and its findings is provided in this report.

Table 3-2: Upper completion tubing size and material selection

Tubing	Tubing Size (Inches)	Tubing Weight (lbs/ft)	Tubing material
Tubing Hanger to SSSV	4 ½	13.5	S13Cr
2-3 Joints directly above SSSV	4 ½	13.5	Alloy 825/S13Cr
SSSV to Crossover	4 ½	13.5	13Cr
Below Crossover	3 ½	10.2	13Cr

13Cr is susceptible to localised corrosion in wet conditions when O_2 is present. Under typical Goldeneye injection conditions a limit of 1 ppm (by volume) 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. In case O_2 is present at higher levels, it is still only a threat under wet conditions which are not expected to occur under normal operation conditions.

A single well will not be able to inject from the minimum to the maximum injection rate due to the limited injection envelope per well. A combination of available injector wells should be able to cover the injection rate ranges arriving to the platform. The completion sizing also considers overlapping of well envelopes to give flexibility and redundancy in the system for a given CO_2 arrival injection rate.

Table 3-3: Proposed tubing crossover depths

Well No.	Crossover depth (ft.)
GYA01	6700
GYA02s	7200
GYA03	~8000
GYA04	5400

The top section of tubing (above the SSSV) will be exposed to cold temperatures during transient conditions i.e. well start up, close in or periodic safety valve testing. In addition, under uncontrolled releases of CO_2 the tubing above the safety valve will be subjected to low temperatures around -60°C. (The likelihood of such a significant uncontrolled release of CO_2 leading to these cold conditions is extremely low). In order to withstand these conditions Vam Top HT has been selected as the optimal thread connection for all the tubing and equipment to be installed above the SSSV. For standardisation this has been extended to all the 4 ½" in components. Further finite element analysis (FEA) is underway to validate this selection.

As the 3 ½" tubing and components will not see vast reductions in temperature (always submerged in dense phase CO_2) Vam Top connections have been chosen for this section.

The sealing mechanism in premium thread connections relies on having sufficient stress on the seal face. When the connection is cooled the box and pin will undergo some shrinkage. The rate of shrinkage will most likely not be the same for the box and pin end of the connection. The Vam Top HT connection is made up to higher torque values which will help compensate for this relative shrinkage effect.

The loads in the different tubing section in the wells have been calculated using WellCat. These load cases represent standard injection operation, transient conditions such as shut in and well start up and some highly unlikely events which lead to extreme conditions. Under all cases the tubing sections present loads within the design criteria. Examples are presented for the 4 ½" and 3 ½" tubing sections in Figure 3-6 and Figure 3-7 respectively.

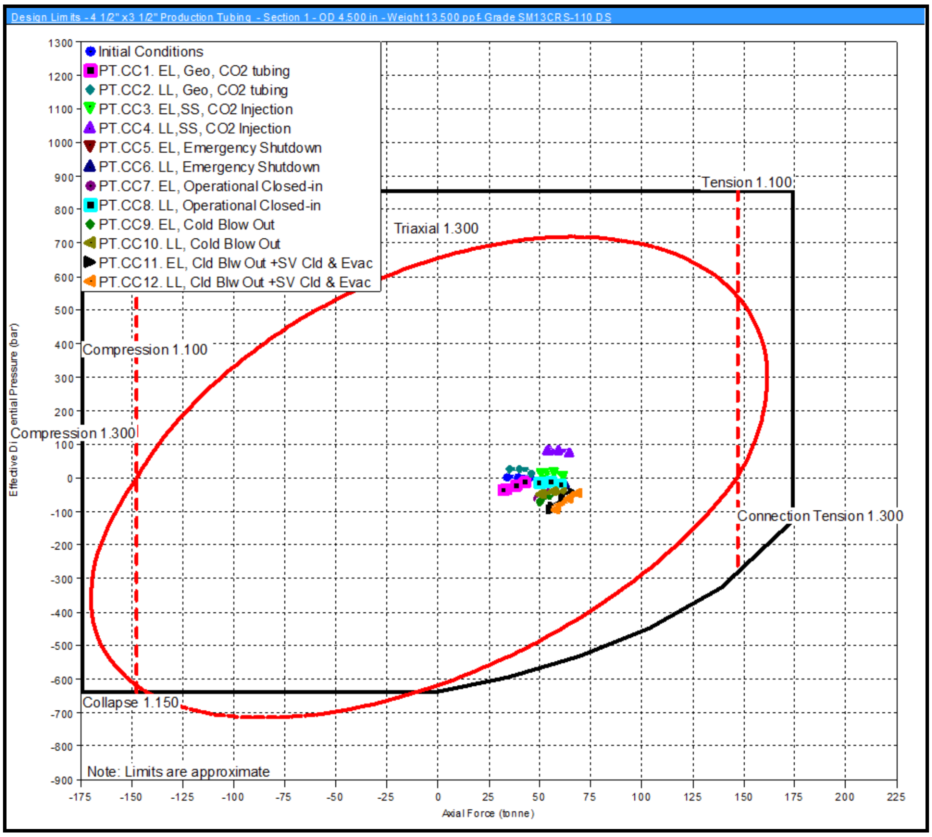


Figure 3-6: **Design limits for 4 1/2" 13.5 lb/ft. S13Cr110 tubing in GYA02S1 proposed completion**

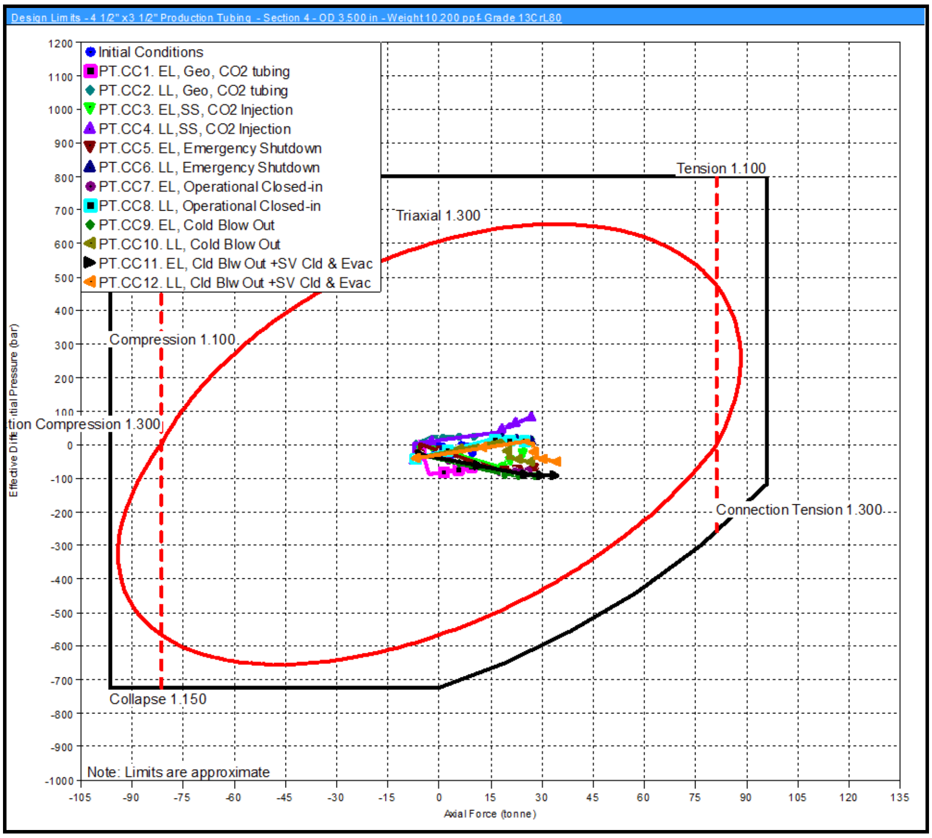


Figure 3-7: **Design limits for 3 1/2" 10.2 lb/ft. 13Cr L80 tubing in GYA02S1 proposed completion**

3.4.1. Flow Induced Vibration and Instability

High fluid velocities are expected in the wells during CO_2 injection. These velocities raise concerns with respect to flow-induced vibration and the effect that this condition may have on the tubing and tubing connections. In order to eliminate this as a potential risk to the integrity of the tubing string a vibration analysis was undertaken. The scope of the analysis was to make an assessment of the mechanical integrity of the tubing crossovers due to internal excitation of the fluid resulting from high fluid velocities. The results of the analysis are discussed in the Well Completion Concept Select (Key Knowledge Deliverable 11.097) (9). As a result of the analysis a maximum velocity in the tubing of 12 m/s will be used to restrict the wells envelope.

The 12 m/s maximum velocity is equivalent to having the following injection rates in different tubing sizes (see Table 3-4).

Table 3-4: Maximum injection limit due to velocity in tubing

Tubing Size, (inch)	Internal Diameter, (inch)	In-situ Injection Rate for 12 m/s in the tubing, m^3/d	Injection Rate for 12 m/s in tubing, MMscfd (CO_2 ~ 970m m3/d)
4 ½"	3.958	8230	120
3 ½"	2.922	4700	68

With 3 ½" tubing the maximum injection rate per well would be 68 MMscfd which is higher than the capacity of the capture plant (63 MMscfd).

3.4.2. Low Temperature Material Embrittlement

From modelling the CO_2 temperature during transient conditions is predicted to be in the order of -20°C. The tubing temperature will be in the order of -15°C. The estimated effect on the production (10 ¾" x 9 5/8") casing is that the temperature will drop to -10°C.

Minimum service temperatures for metals are listed in Shell design standards. When the metals cool, they lose toughness, which could then become an issue when subjected to mechanical load. The minimum service temperature of metals is the temperature above which they will show acceptable toughness if subjected to shock loading.

For standard 13Cr steel, the minimum service temperature of -30°C is well below the expected -15°C for the tubing wall. In addition to the transient conditions another hypothetical (highly unlikely) scenario was modelled involving a release of CO_2 at surface. If the leak size is modelled to be conservatively large it indicated cooling of the tubing to -60°C. It is for this reason that Super 13Cr has been selected for the tubing material above the SSSV. Super 13Cr shows adequate toughness down to the prescribed temperatures but requires impact testing to qualify at those temperatures. This is under review with Shell material experts and OCTG supplier.

In order to prove that the existing L-80 CS casing is suitable down to -10°C, it is necessary to demonstrate by low temperature impact toughness tests that embrittlement is not an issue. Available certificates that supported the quality of the installed casing were analysed and Charpy values demonstrating adequate toughness down to -40°C were noted.

3.5. Safety Valve

A subsurface safety valve (SSSV) is installed in the completion to provide emergency closure of the producing conduits in the event of an emergency. The safety valve forms part of the emergency shutdown (ESD) system and is designed to be fail-safe. Hydraulic pressure is maintained on a control line down to the valve in order to keep it open. Loss of pressure in the control line leads to the closure of the valve, see Figure 3-8.

Given the presence of hydrocarbons in the reservoir, the ability of the CO_2 to flow to the external environment and its health, safety and environmental (HSE) implications in case of an uncontrolled release it has been decided to include a safety valve in the upper completion. This is in line with well integrity management standards which state that wells capable of natural flow of hydrocarbons will be fitted with a surface controlled SSSV that has pump through capability.

The SSSV will be positioned deep enough in the well so as to be unaffected by the same failure mechanisms that can compromise surface ESD systems, and shallow enough that closure times are not compromised by having to overcome high hydrostatic pressures in the control line and to facilitate the testing of the valve by reducing the volume to bleed off. Other factors that determine the final setting depth for the SSSV are the predicted depth that hydrates form, the temperature limitations of the valve and the crater depth. The proposed SSSV depth in the CO_2 injection wells will be similar to the current SSSV setting depth (~2500 ft).

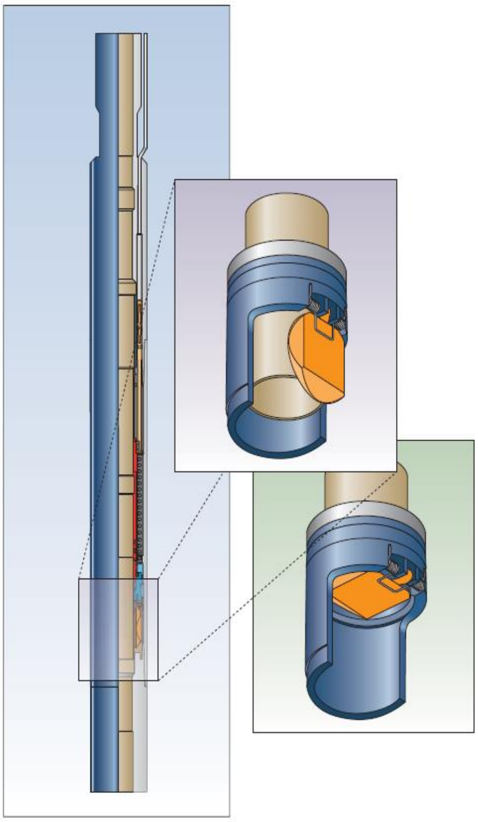


Figure 3-8: SSSV in open & closed position

Note: Figure courtesy of Schlumberger

The lower end of the temperature rating of SSSVs available in the market is -7°C.

OLGA™ simulation has indicated that in the transient design case for 'A' annulus with base oil, -7°C temperature is observed at around 1500ft. and sub-zero temperature is expected in the well at 1950 ft depth. For the transient design case with a N_2 cushion in the 'A' annulus the depths are 1650 ft for -7°C and 2050 ft for sub-zero temperatures in the CO_2 stream. This implies depths below 2050 ft are ideal for the placement of the SSSV.

In a highly unlikely scenario where CO_2 is released into the atmosphere, the CO_2 temperature will drop which will affect the well components, see Figure 3-1. In the case of a surface release, the SSSV will be closed after the release is detected. A limited amount of CO_2 will be released to the atmosphere as the SSSV is closed. Figure 3-9 illustrates how the tubing contents above the closed SSSV flapper will empty out from the well. The release size will determine how fast the tubing will be emptied. The CO_2 liquid/gas interface and associated cold front will travel down the well until it reaches the SSSV and will stay there until all liquid CO_2 boils off into gas at low pressure. This will create cold conditions at the SSSV. Such a scenario will be avoided by shutting the Christmas tree valves where the release is upstream of these valves. Setting the SSSV deep in the well allows it to effectively shut before the cold front reaches it.

The tubing volume between the Christmas tree and the SSSV is approximately 6.3 m^3. Should this volume be released to atmosphere the SSSV temperature will drop close to the triple point (-56.6°C). If the SSSV has a migration path across the flapper for dense phase CO_2 to cross then further cooling will take place localised to the SSSV. SSSVs currently available on the market will require additional testing/qualification and possibly some design modifications to suit the conditions in the well in this highly unlikely event. This information has been formally shared with SSSV vendors.

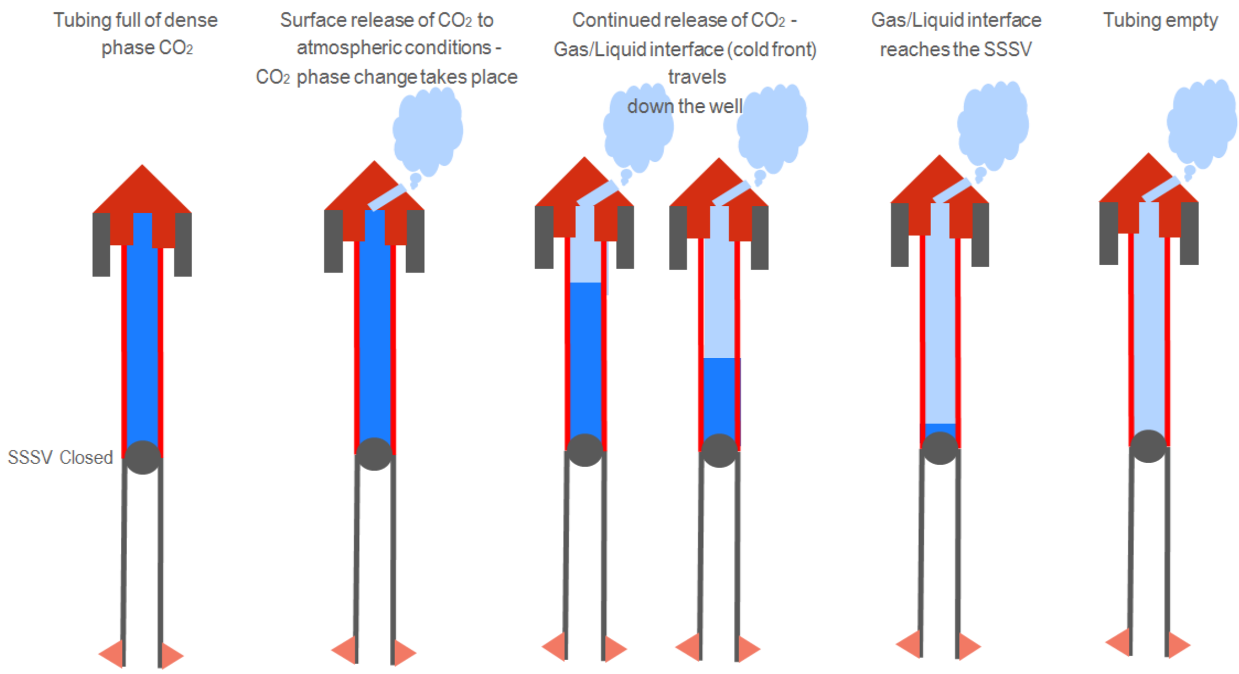


Figure 3-9: Process of emptying the tubing in a highly unlikely surface release scenario

Testing of the SSSV is a controlled operation. The pressure above a closed flapper is typically bled off to 10% of the closed in tubing head pressure (CITHP) and the pressure is then monitored. To conduct an unambiguous test the surface pressure needs to be monitored in a single phase. In the case of CO_2 this implies gaseous phase. In order to manage the temperature of the well during the SSSV testing the pressure will have to be maintained above a certain value. The testing procedure is predicted to be a lengthy process (approximately 24 hours.). Distributed temperature sensing (DTS) will be installed as part of the in-well monitoring will assist in this operation and reduce the overall time required. The procedure for testing the SSSV is detailed in the report Well Operation Guidelines (6).

To reduce the risk of hydrate deposition it is proposed to displace Methanol as an inhibitor between the SSSV and the Christmas tree when the well is closed in. The exact volume of Methanol to be displaced varies with the reservoir pressure and is explained in the Well Operation Guidelines (6).

3.5.1. Hydraulic Control line & Fluid

A ¼" alloy 825 control line will be used to maintain hydraulic pressure on the SSSV. This control line will be terminated to the SSSV using the vendor's proprietary connection. The control line will be run to surface along with the upper completion tubing string. It will be secured to the tubing with cross coupling protectors installed at every tubing joint, see

Figure **3-10**.

The ¼" control line will be encapsulated in 11mm x 11mm protective material such as Teflon or Tefzel.

It is crucial that the encapsulation material is suitable for the environment in which it will be installed i.e. Annulus fluid and expected temperatures.

The hydraulic fluid needs to be compatible with all the seals and is required to have suitable thermal properties i.e. low pour point to ensure that it does not freeze under the low temperature excursions described in this report.

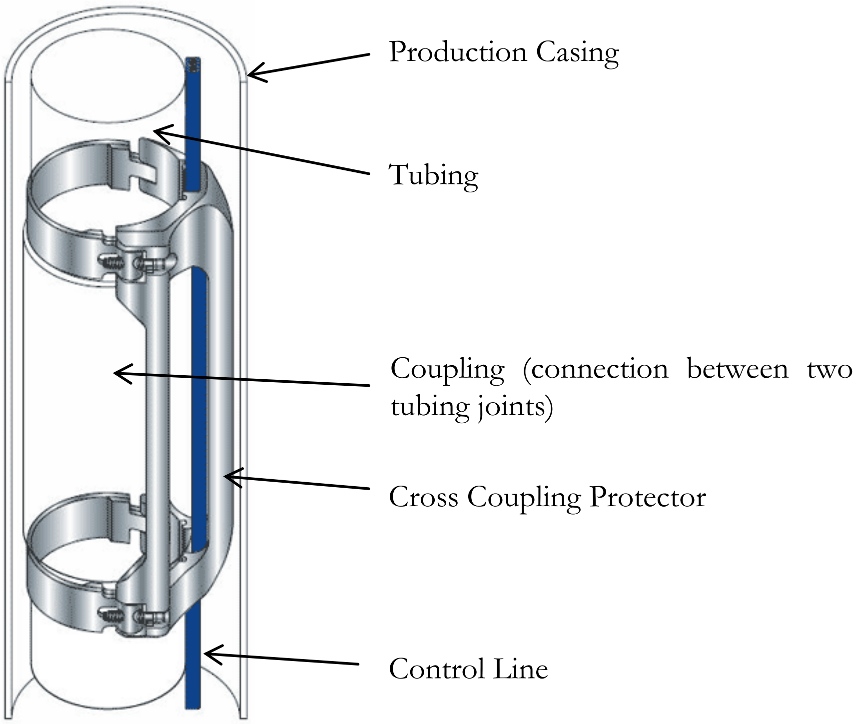


Figure 3-10: Cross Coupling Protector securing control line to tubing

3.6. Production Packer

The production packer has two primary functions, to seal differential pressures effectively and to anchor the tubing to the casing over a large variety of operating conditions. The packer provides a barrier in the annulus preventing well bore fluids from interacting with the production casing above the packer setting depth thereby protecting the casing. A standard 9 5/8" x 3 ½" inch hydrostatic/hydraulic set production packer made from 13Cr material has been selected, see Figure 3-11. Due to the application an ISO 14310 V0 specification has been applied to the packer. The packer is placed deep in the well where even under highly unlikely surface release of CO_2 scenarios the CO_2 remains in a dense phase and it is hence not subject to low temperature cooling due to JT effects. The current bottom hole temperature (BHT) is 83°C. The expected temperature during injection conditions is around 20°C.

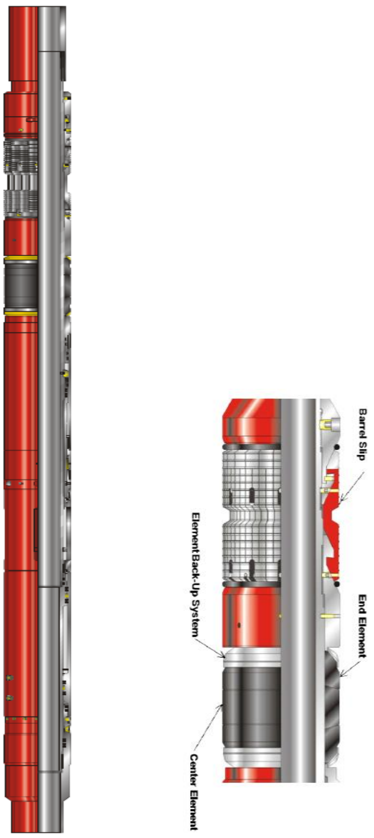


Figure 3-11: Production Packer

Note: Figure courtesy of Halliburton

It is proposed to use a HNBR (Hydrogenated Nitrile Butadiene Rubber) elastomer-sealing element. HNBR, also known as "Highly Saturated Nitrile" (HSN), is a special class of nitrile rubber that has been hydrogenated to increase saturation of the butadiene segment of the carbon polymer backbone. Improvements to the material properties, over that of a nitrile rubber (NBR), include greater thermal stability, broader chemical resistance, and greater tensile strength. HNBR can be formulated to meet application temperatures ranging between -50°C and 165°C (-58°F-329°F). The element package uses a three piece multi durometer system consisting of a soft centre and hard end elements. The harder end elements expand against the packer mandrel and provide an extrusion barrier for the softer centre element. This provides an effective seal in both high and low pressure applications and casing irregularities which may be encountered as the existing production casing string is being re-used and the production packer is being set deeper in the well in a section of casing that has previously been exposed to wellbore fluids.

The use of barrel slips allows for the packer to casing loads to be distributed more evenly and over a larger contact area.

An incorporated cut to release feature ensures a large enough packer envelope to cover the load cases expected during the entire injection lifecycle. The cut to release feature allows for ease of retrieval of the packer when required. It requires an accurate radial cut to be made at a specified target zone in the packer mandrel. For correlation purposes it is possible to include a PIP tag. This can be built into the packer as a sub or can be incorporated in a cross coupling protector. Having a reference point of this form assists in future packer retrieval operations. Another option that can be incorporated is the inclusion of a latching sub below the packer. This can then be used to locate a radial cutting torch (RCT) to cut the packer mandrel.

3.6.1. Packer placement

It is planned to position the packer in the well across the Hidra marl which is considered part of the reservoir seal. The existing lower completion screen hanger is either set at the Rødby formation or the Hidra formation. Currently, the production packers in GYA01 and GYA05 are set in the Chalk group, see Figure 2-2. In these wells the plan is to install the packer deeper in the Hidra formation. The existing production packers in GYA02S1, GYA03 and GYA04 are currently set in the Hidra formation. The final placement of the new packers for CCS operations within the Hidra will depend on the status of the production casing at the time of the workovers. 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. At the same time it also planned to carry out cement bond analysis. This will ensure correct packer placement and facilitate future abandonment operations.

The proposed production packer placement depth in relation to the existing lower completion and key production casing features are shown in Figure 3-12.

Injection Wells depths vs Top of Cement (ft.)

	GYA-01	GYA-02s1	GYA-03	GYA-04	GYA-05
Theoretical Top of Cement	7506	9490	7865	11510	6895
Top Plenus/Hidra Marl	8547	10485	8799	12154	7961
Proposed Packer Setting Depth (40'-100' above SC-2R packer)	8656 - 8596	10800 - 10740	9050 - 8990	12668 - 12608	8055 - 7995
Cement to Top Plenus/Hidra	109 - 49	315 - 255	251 - 191	514 - 454	94 - 34
SC-2R Packer (screen packer)	8696	10840	9090	12708	8095
Cement to Top Plenus/Hidra	149	355	291	554	134
FIV (cut point)	8755	10900	9150	12768	8155
Cement to Top Plenus/Hidra	208	415	351	614	194
Uniflex 7.00" Liner Hanger	8831	10955	9196	12832	8237
Cement to Top Plenus/Hidra	284	470	397	678	276
9-5/8" Casing Shoe	9006	10990	9365	13010	8395
Cement to Top Plenus/Hidra	459	505	566	856	434
Proposed packer above 9-5/8" Shoe	350 - 410	190 - 250	315 - 375	342 - 402	340 - 400

Existing Well Scehmatic GYA-01

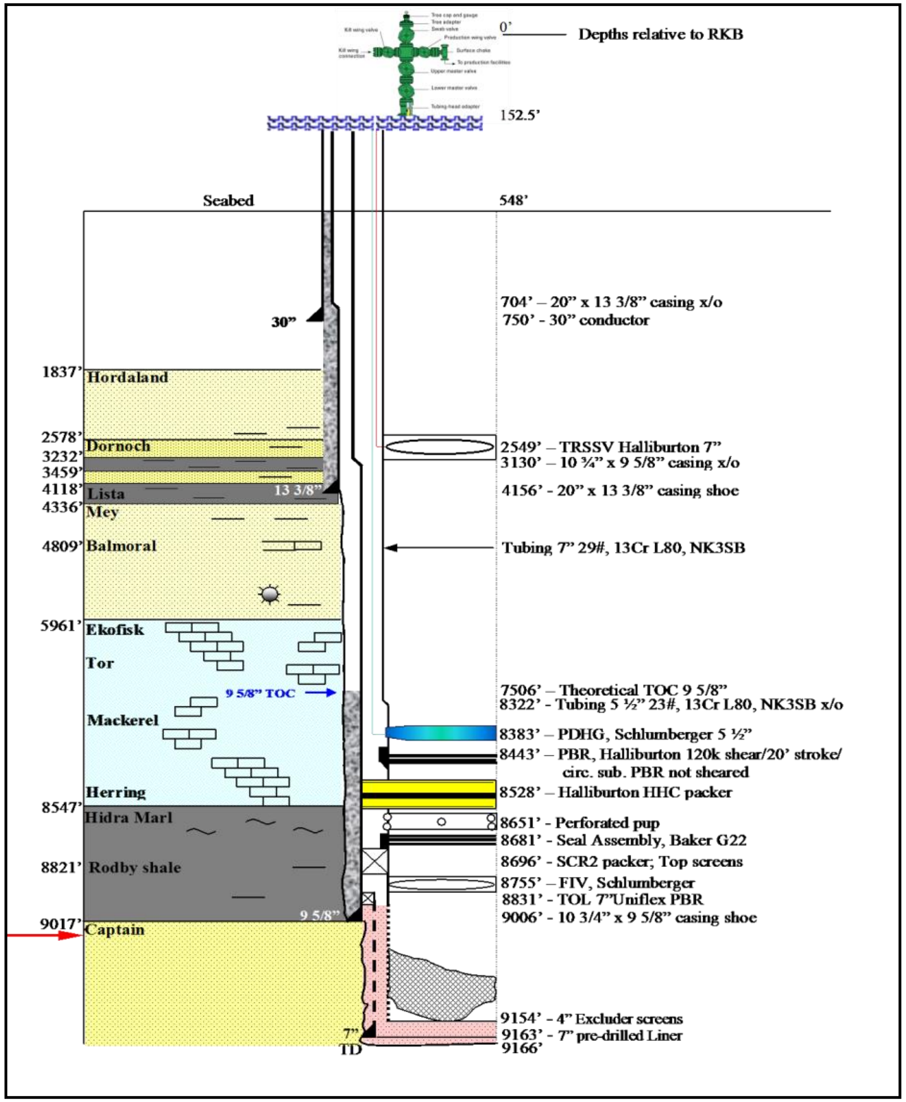


Figure 3-12: Proposed production packer placement depth

3.6.2. Landmark WELLCAT analysis

Tubing stress analysis is a fundamental component of all completion designs. The analysis allows for all the installation and injection life load cases to be modelled and it provides a check to confirm none of the cases exceed the design limits of the components installed in the well. The proposed well design was modelled in Wellcat and all the expected load cases were built into the software. In addition to the expected load cases some highly unlikely scenarios (worst case) were also modelled to define the limits of the design. All results were found to meet the criteria of the Shell casing and tubing design manual (CTDM).

As part of the analysis packer loads were investigated and all loads were found to lie within the packer design limit. Figure 3-13 shows all the modelled loads (Well GYA02S1) at the packer are within the packer performance envelope.

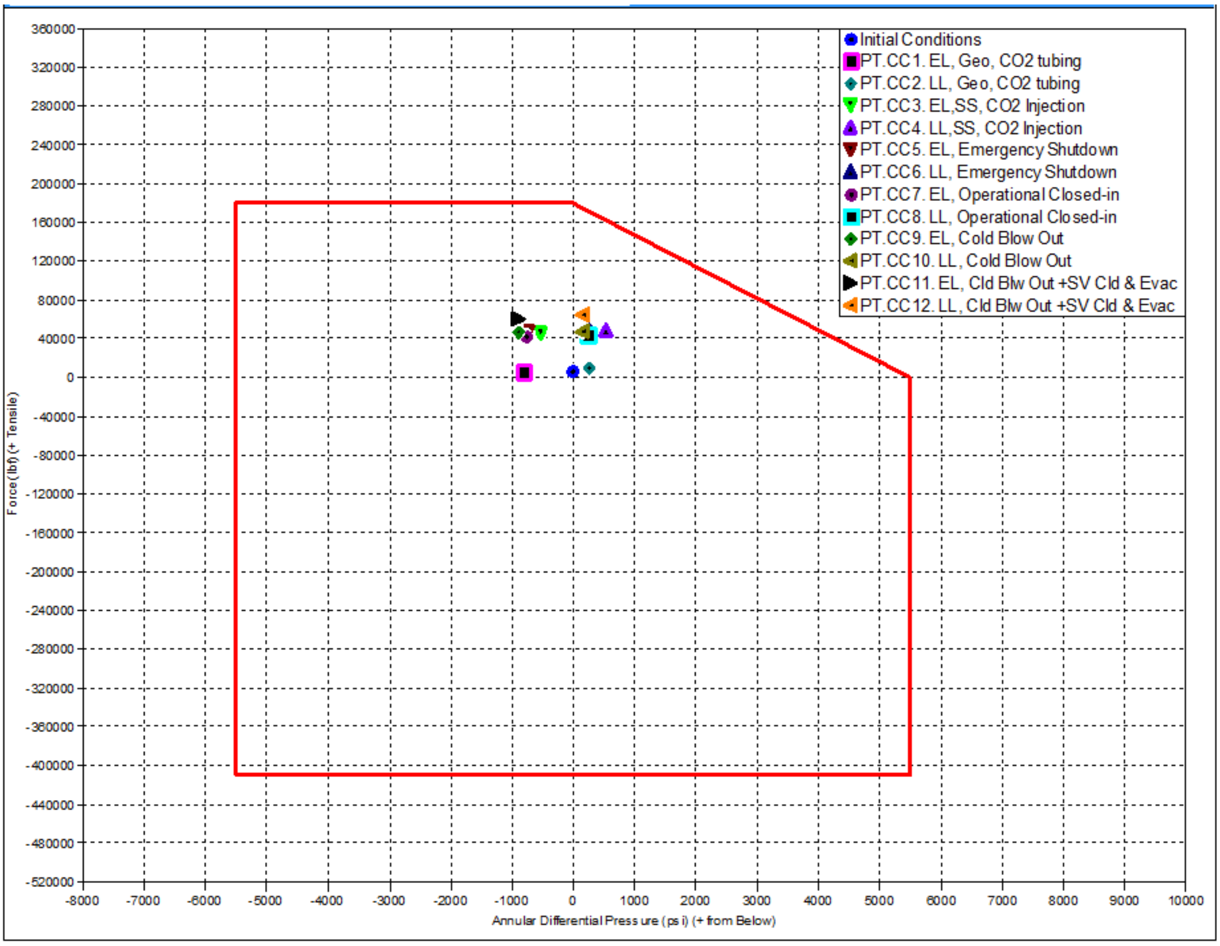


Figure 3-13: Design limits for proposed production packer, well GYA02S1

When CO_2 injection commences, well temperatures will drop. This was studied in detail and is reported in the Well Completion Concept Select report (9). This drop in well temperature is similar to what is experienced routinely in water injection wells.

The drop in temperature will lead to casing contraction and negative wellhead growth (i.e. the wellhead made up to the 20" casing will move down, and the tensile stress in the 9 ⅝" production casing will decrease). This was modelled using the software mentioned above and the results confirmed that the existing casing strings remain within their tensile and compression design limits, see Figure 3-14.

In addition, the results for the combined casing string contraction predict that the wellhead will move down 1 1/7" under CO_2 injection conditions. This means that the wellhead, annulus valves and flowline will remain above the top of the 30" conductor, and that the Christmas tree flowlines will not clash with other wellbay items due to wellhead movement.

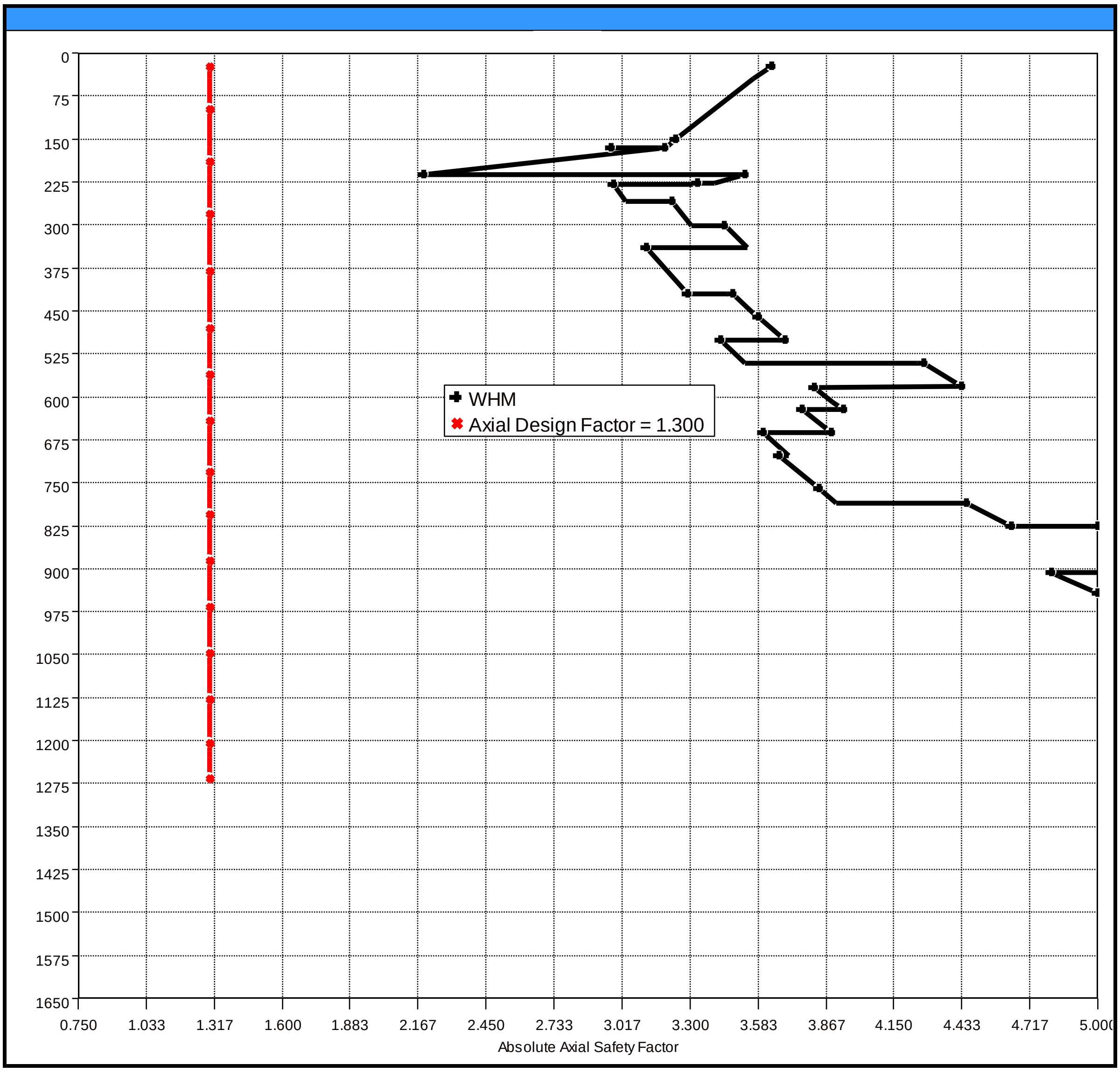


Figure 3-14: Surface casing axial loading under injection conditions

3.7. Circulation device

In order to circulate out and replace the A annulus fluid to base oil and to install the required N_2 cap in the A annulus the inclusion of a circulation device in the completion design is essential. A sliding sleeve (Figure 3-15) run as part of the upper completion tubing string above the production packer allows for ports to be mechanically opened and closed allowing controlled communication between the annulus and tubing. Another option available is the inclusion of a gas lift mandrel and valve as part of the upper completion above the production packer.

Figure 3-15: Sliding Sleeve – Circulation Device

The sliding sleeve is designed to perform and maintain seal integrity over repeated cycles. For this application the intention is to use the device only once at the workover stage. The sliding sleeve uses a non-elastomeric seal package which provides resistance to down-hole environments. The non-elastomer seal package comprises PEEK, Teflon and an engineered composite which is chemically inert and has friction reducing/lubricating qualities and good abrasion resistance. This leads to increased sealing reliability and reduced shifting forces. The shifting tool provides positive indication that the sleeve has been shifted. The sleeve design also incorporates a collet lock mechanism that keeps the sleeve in its required position.

The benefits of the gas lift mandrel and valve option is that it removes the need to run a shifting tool to open and close the circulating port. The circulation path is created by applying pressure in the annulus. Designs exist where additional pressure applied to the annulus allows for the gas lift valve to be locked in the closed position after its use. This helps ensure a leak tight seal is maintained for the duration of the well life. Gas lift valves with metal to metal seals and ISO 17078 V0 testing (most stringent testing criteria) are available. The gas lift mandrel unlike the sliding sleeve does not create a restriction in the tubing and isn't susceptible to accidental opening during other planned slickline intervention activities.

The gas lift mandrel also provides a protected channel for the permanent monitoring control line to pass across its body. Placement of the control line in this channel keeps the control line away from the injection ports. A similar arrangement can be requested for the sliding sleeve. This is only applicable if the monitoring gauges are to be installed below the circulating device.

In addition to the options described above remote operated circulating valves are also available which allow tubing-annulus communication to be achieved simply by applying tubing pressure. These valves are again deployed as part of the tubing string above the production packer. Once the packer is set a pressure signal is sent to the device by tubing pressure application which opens the circulating ports. Once closed these valves also offer a metal-to-metal V0 rated seal.

3.8. Monitoring

As described earlier re-completing the wells provides an opportunity for optimising the well monitoring capabilities. The new upper completion will be used to deploy a number of well monitoring technologies such as permanent downhole pressure and temperature gauges, distributed temperature and acoustic sensing. These technologies will allow for long term and real time reservoir monitoring, understanding of CO_2 behaviour and plume migration in the reservoir, early identification of injectivity issues and tubing to annulus communication. The distributed temperature sensing (DTS) will also assist in activities such as the SSSV testing and will help reduce the time required for these periodic tests. Distributed acoustic sensing will allow for flow profiling and analysis and vertical seismic profiles to be acquired which will collect seismic velocity data.

Multiple permanent downhole pressure and temperature gauges will be installed in the wells to monitor pressure and temperature at critical points. These will be multi dropped on a single electric line to surface, see Figure 3-18. The gauges are connected to the completion string via gauge mandrels that are made up to the tubing, see Figure 3-16.

Figure 3-16: Gauge Mandrel & Gauge

Each gauge is then connected to an electric line which is run to the surface along with the tubing string. The electric line is clamped to the tubing at each tubing connection with a cross coupling protector. As per the design a gauge will be installed deep in the well close to the production packer to acquire data as close to the reservoir as possible. At a predetermined height from this a second gauge will be installed. This will provide redundancy to the first gauge and also allow for a density measurement to be inferred. The lowest mandrel will also carry a gauge which shall monitor the annulus pressure and temperature. A final gauge will be installed at the cross over from 4 ½" to 3 ½" tubing. This will be installed to understand the CO_2 behaviour at this critical point in the completion. This will only be effective in the injection wells and hence in the monitoring well this will be installed deeper in the well to provide an additional measurement in the tubing which will help further understand the complexity of fluids in that well through recorded pressure (density) changes. In total

4 permanent downhole gauges will be installed per well, 3 monitoring the pressure and temperature in the tubing and 1 measuring the pressure and temperature in the annulus. Deployment of such systems is standard practice within the North Sea and extensive knowledge of this exists within Shell UK. There is an option for reducing the number of gauges in wells GYA04 as this well is planned to be put on injection later in the project by which time the project would have collected sufficient amount of data to understand the CO_2 behaviour in the tubing removing the need for the x-over gauge.

Pressure and temperature modelling suggests that the bottom hole Temperature (BHT) is likely to be in the region of 17°C-35°C [63°F - 95°F]. Currently pressure and temperature gauges are routinely calibrated for temperatures in the range 25°C-150°C [65°F-302°F]. Therefore further qualification of the system will be required before it can be utilised on Goldeneye for CCS operations.

In addition to the single point pressure and temperature sensors described above distributed temperature sensing (DTS) will be installed in the wells. This will provide a temperature profile along the entire path of the well from surface to close to the production packer. In order to deploy DTS a fibre optic line will be run along with the electric line. This may be bundled together with the electric line in a single encapsulated control line or it may be deployed as an independent ¼" line with multiple fibre lines for redundancy. The DTS will assist in understanding the behaviour of CO_2 in the well, during transient conditions (opening and closing the well and SSSV inflow testing) the temperature profile will assist in operations and also help reduce the time for some of these operations. In the unlikely event of a tubing leak, the distributed temperature readings would facilitate the location of the leak. DTS will also help identify the position of a gas/liquid interface (Figure 3-9) in the well and follow its movement down the well.

Distributed acoustic sensing (DAS) will also be incorporated within the monitoring package. Similar to the DTS system this involves running an additional fibre optic line to surface. Again this line may be bundled with the electric line or may be run as a separate ¼" line with the DTS and DAS fibre lines combined. Having DAS installed in the well is similar to having acoustic receivers stationed along the wellbore and as such it allows for periodic vertical seismic profiles (VSP) to be acquired. Using DAS for this technique provides excellent coverage along the entire length of the well. The sensitivity of the system is not as good as having dedicated geophones in the well and with DAS some of the directionality is also lost. The technology is still in its early stages and improvements are being made. With these improvements the sensitivity is also increasing and DAS may also be used for monitoring seismicity.

The control lines (¼" tube) are fed through the tubing hanger and exit the wellhead through a dedicated wellhead outlet. If a combined electric and fibre optic control line is deployed then a hybrid well head outlet will be installed at surface where the electrical and fibre optic lines are split and connected to the surface lines to the control room where the respective surface acquisitions units will be placed, see Figure 3-17.

If separate electric and fibre optic control lines are deployed then two ports will be required in the tubing hanger for the monitoring system and two wellhead outlets will be required at surface, one electrical wellhead outlet and one optical wellhead outlet.

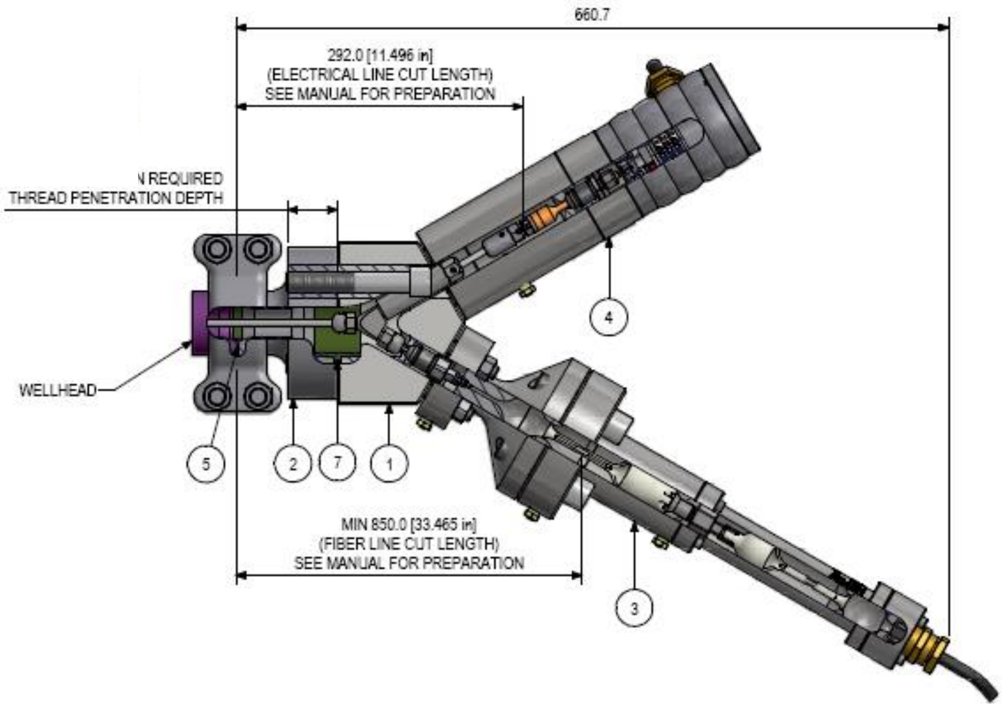


Figure 3-17: Hybrid Wellhead Outlet

Note: Figure courtesy of Schlumberger

As part of the topside refit new cables will be laid between the wellhead area and the control room. In addition to the standard electrical lines this surface cabling will also incorporate fibre optic lines for the DTS and DAS communication with the surface acquisition units. A summary of information on the surface units (space required, bandwidth requirement for data transmission and power requirements) is provided in the Well and Reservoir Management Plan (4).

Data from the permanent down hole pressure and temperature gauges will be available live through the PI server. DTS data is considered critical during transient operations such as well start up and activities like SSSV inflow testing during these periods of interest the DTS data will be made available. Due to the high number of data points available in DTS (spacial resolution can be set to as low at every half meter) it is not planned to have all the data available in PI. The data will therefore bypass the platform distributed control system (DCS). This reduces the number of PI data tags required. The optimal methodology to manage and transfer this data is currently under review and will be developed in the next project phase.

Due to the large volume of data generated by DAS the data will be retrieved as and when required, some of the data computing for DAS may also be carried out in the control room to reduce the amount of data that is required to be transmitted. The actual DAS data may then be retrieved from the rig and hand carried onshore if required. These measures allow the total bandwidth requirement to be limited.

Requalification of the in-well components to maintain integrity in potential low temperatures and to withstand the cold front (gas/liquid interface) will be required prior to deployment. The worst case conditions have been shared with vendors and the vendors have been engaged to develop a timeline for the necessary qualification/testing.

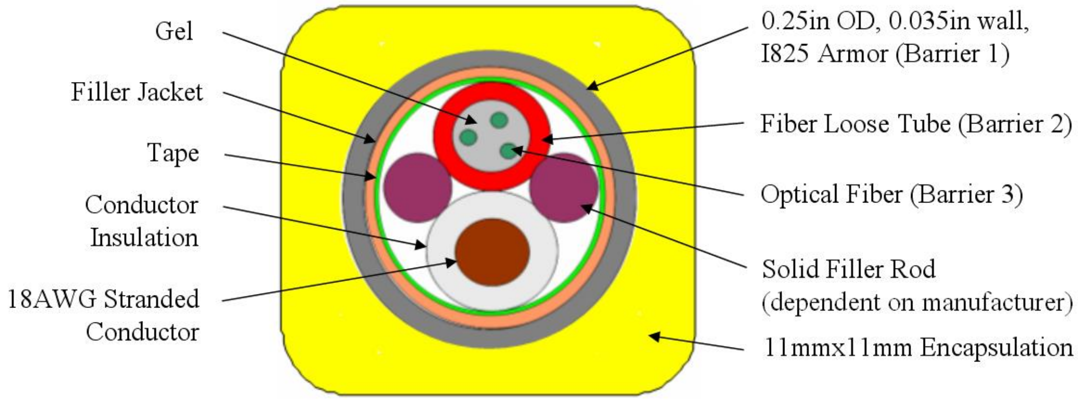


Figure 3-18: Hybrid Cable – Combined Electrical and Fiber Optic Line [from Schlumberger]

Note: Figure courtesy of Schlumberger

3.9. Lower Completion

The lower completion consists of a gravel pack including 4" premium screens set inside a 7" pre-drilled liner across the reservoir. The current wells were drilled only in the top 60 ft - 70 ft [18.3-21.3m] (vertical depth) of the main reservoir - Captain D. See Figure 2-2, and Figure 2-4.

The lower completion comprises of 13Cr steel. This is valid for the 4" Screens and 7" Pre-perforated liner. To avoid expensive side-tracks it is recommended to control the Oxygen in the injection fluid to acceptable levels. This has been calculated at 1 ppm Oxygen in the CO_2 stream.

From the analysis to date, there is no reason to sidetrack the wells to install a new lower completion and hence the lower completion will not be changed during the workover operations. There are some operational restrictions related to the characteristics of the CO_2 and some limitations related to the size of particles in the injected CO_2. Based on the productivity during the hydrocarbon production phase it is not required to stimulate the wells for the CO_2 injection. A detailed review of the lower completion is included in the Conceptual Completion and Well Intervention Design Endorsement Report (1).

Plugging

Plugging will reduce the injectivity through the screens and gravel with time. Under injection any particles bigger than a critical size will start to accumulate internally at the screens, smaller solids can pass the screens but may accumulate in the gravel; even smaller solids may travel through the gravel.

Due to the possible presence of solids in the injection stream filtration of the CO_2 is required. The internal volume of the screens across the Captain D reservoir is very small, from 0.31 m^3 to 0.55 m^3 (1.9 bbl - 3.4 bbl.) (depending on the well). There is no allowance for accumulation of solids inside the screens. It is therefore recommended to carry out filtration to 17 micron to avoid the plugging of the lower completion; more stringent filtration to 5 microns is required to avoid the plugging of the formation. A 5 micron filtration system with redundancy is planned to be installed on the platform during the topside construction phase.

Erosion

Erosion is one of the most common mechanisms of screen failure. Screen erosion is a progressive failure that depends on fluid velocity, particle size and concentration and fluid properties. Erosion of the screen can be caused by the high downhole flow of fluid through the screens. The presence of solids will increase the erosion rate. The use of filtration methods described above reduces the potential for erosion.

During the injection process the CO_2 will contact the screens before the gravel and as such the restrictions for stand-alone screens (SAS) related to erosion should be applied (instead of the gravel pack restrictions). Liquid limitations (instead of gas limitations) should be used as the density of the CO_2 at bottom hole injection conditions will be very high ~920-940 kg/m^3. For liquid flow the normally accepted industry velocity is 1 ft/s [0.3m/s] for production conditions.

In order to avoid high downhole injection rates during injection start-up it is recommended to start-up the injection over a 30-60 minute interval. This is explained in the Well Completion Concept Select report (9).

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 lower completion will be surrounded by water at the time that CO_2 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 and consequently 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. The cooling of the injection well and the surrounding reservoir matrix will create conditions favourable for the formation of hydrates.

In order to reduce the risk of hydrate formation during the first years of injection (once water is displaced from the wellbore) it is required introduce batch hydrate inhibition prior to injection start-up. If water is subsequently introduced into a well and/or it is suspected that water is present in a wellbore, then batch injection should continue. Methanol is currently preferred as an inhibitor. Batch hydrate inhibition features as an instruction in the well operational procedures included in the Well Operation Guidelines (6).

3.10. Fluid Selection

In order to workover the wells it is required that the wells are first "killed" (operation of placing a column of heavy fluid into as well bore to prevent the flow of reservoir fluids) and the reservoir isolated; the workover carried out; and then the recompleted well put "on injection". These stages of well construction are discussed in Section 0 Constructability. At each of these stages there are different fluid requirements in the well.

Prior to working over the wells reservoir isolation will be required. For this it is possible that a fluid based pill might be used with a fluid column above the pill to maintain a hydrostatic pressure overbalance. During the well clean out operation prior to running the new upper completion there is a requirement for clean-up fluids and circulation fluids, these are discussed in section 4.3.

The completion fluid and packer fluid options and selection criteria are discussed here.

3.10.1. Completion Fluid

Once all workover operations have been carried out, the tubing hanger and tree will be installed and pressure tested. This will then allow for final well hook up and flow of CO_2 through the pipeline to the platform. The completion fluid left in the tubing will be compatible with the well components and with the formation. Additionally, the fluid will help minimise the JT effect caused by expansion of CO_2.

From the injectivity perspective it is preferred to have water or gas, rather than base oil or diesel to avoid the introduction of a new phase in the wellbore, which might affect the relative permeability to CO_2. However, the volume of base oil to be displaced by the CO_2 is small and the CO_2 will fully displace the base oil around the wellbore due to its predicted miscibility. Additionally, there will be enough injection pressure available during the initial stage of injection to overcome any relative permeability effects.

The ideal case is to have a fluid in the tubing which will lead to a wellhead (WH) pressure in the order of 35 bara to 70 bara. Under this scenario, the JT cooling will be minimal during initial start-up operations. In the case of a single fluid in the tubing which gives a WH pressure of 35 bara at 196.5 bara bottom hole pressure, the required fluid column density is 0.283 psi/ft [0.064bar/m]. This will however lead to difficulties of running the completion in an underbalanced well.

In the case of having water in the tubing, the WH pressure will be close to atmospheric pressure. In this scenario at CO_2 injection start up the CO_2 will flash and JT cooling effect will prevail.

In the case of base oil (pressure gradient of 0.35 psi/ft) the hydrostatic pressure exerted by the base oil will be in the order of 2860 psia [197 bara] at reservoir level. This pressure is not sufficient for well control.

The current design plan is to carry out workovers in inhibited seawater. This fluid is compatible with the completion equipment. The expected WH pressure is around atmospheric due to the fluid column weight and the low reservoir pressure. Prior to injecting CO_2 it is therefore necessary to install a N_2 cushion in the top of the well to increase the tubing WH pressure to 35 bara in order to reduce the JT effect during the initial injection.

The true vertical length of the N_2 cushion in order to obtain 35 bara (500 psia) in the top of the well assuming water of 0.44 psi/ft gradient below the N_2 and 2850 psia reservoir pressure is estimated at around 2900ft. The initial well start-up process is described in the Well Operation Guidelines (6).

3.10.2. Packer Fluid

During transient operations (close-in and start-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, see Figure 3-2. As a result of this the annulus fluid in the top of the well will also see a reduction in temperature. This forms a key factor in the annulus fluid selection.

The fluid left in the A annulus for Goldeneye Wells will have the following characteristics:

- Avoid/minimise corrosion of the tubing and production casing.
- The rheological properties of the packer fluid will be stable during injection period.
- It will have a low freezing point to cope with the well transient conditions and will be stable in terms of phase envelope.
- The fluid will be solids free.
- It will allow for a positive pressure to be maintained at all times which will assist in monitoring of the annulus.

After running the completion and setting the production packer the annulus fluid will be replaced with Base oil. The advantages of base oil over a water based fluid are described in Table 3-5.

Table 3-5: Comparison between base oil and water based fluid in the A annulus.

	Base Oil	**Water based fluid**
Corrosion Management	No corrosion (if no water present) Depends on injection time and place of the tubing leak	Corrosion in the casing (CS) in the case of CO_2 tubing leak (water present in the A-annulus) 1year allowance
Thermal expansion	High ~186 psi/°C For average 30°C temp. change Change in pressure ~5560 psia Or Change in height ~225-330 ft (well)	Medium ~62 psi/°C For average 30°C temp. change Change in pressure ~1850psia Or Change in height ~54-80 ft (well)
Freezing point	Can be tailored to the required temperature (e.g. -11°C or -60°C)	Freezing Temperature Seawater ~-1.8°C Theoretical Min. freezing depression temperature (saturated brine): NaCl -21°C, KCl -9.5°C, $CaCl_2$ -45°C
CO_2 injection aspects	No difference Steady State ~1-4°C top Transient ~-20°C fluid, -11°C A annulus for a short period of time	No difference

The expected A-annulus surface temperature with water based fluid during transient condition is approximately -11°C. Fresh water will freeze at this start-up A-annulus temperature. Seawater will freeze around -1.8°C. If possible, water should be avoided in the well due to formation of carbonic acid and formation of hydrates. In the case of leak there will be limited time to avoid corrosion of the production casing made of carbon steel. Oil based packer fluid will help to avoid/minimise corrosion in the tubing and production casing.

The main concern with base oil as packer fluid is the high thermal expansion/contraction (~180 psi/°C) with respect to water base fluids (~60 psi/°C). For an annulus filled with base oil frequent platform visits would be required to manage the expansion/contraction of the base oil column by topping up during the injection period and bleeding off during the closed in period if a positive pressure is required to be maintained in the A annulus. The proposed solution is the installation of a compressible fluid in the top of the annulus. The benefits of installing a N_2 cushion in the A annulus are outlined in Table 3-6.

Table 3-6: Benefits of installing a N_2 cushion in the A annulus.

	A annulus with N_2 cushion	A annulus Without N_2 cushion
Initial conditions	N_2 cushion: 300 psia, 300 ft of N_2	Positive pressure 150-300 psia Base oil to top of the well
Thermal contraction (from geothermal to injection)	Low - Compressible fluid in the top Fluid interface deeper + pressure reduction (more vol. and lower T for the N_2) +ve pressure maintained. ~140 psia after cooling N_2 Level down to 525-630 ft	Top of the well to vacuum No +ve pressure maintained Change in height ~225-330 ft (well) To keep +ve positive pressure then ~16.5 - 24 bbl of fluid to be topped-up
Thermal expansion (from injection to geothermal)	Low N_2 level rise and pressure increase To ~installation (300 psia, 300 ft N_2 level)	If the well is topped up during the injection (and level at the tree). Change in pressure ~5560 psia due to thermal effects
CO_2 injection aspects	Steady State ~1-4°C top same Transient (short time): -22°C CO_2, -22°C tubing, -6°C A annulus	Steady State ~1-4°C top Transient (short time): -20°C CO_2, -15°C tubing, -11°C A annulus
Well Integrity	OK	Pressure above casing burst pressure of the production casing (8150 psia for 9 5/8" 53# L80), equivalent to a surface pressure of ~5000 psia for 8150 ft TVD and 0.375 psi/ft base oil gradient.
Well Operations	Keep minimum ~60 psia at geothermal conditions (to keep +ve pressure during injection). Echometer to know N_2-fluid level	Frequent platform trips. Topping Up or bleeding off fluid in the annulus for keeping positive pressure.

With a N_2 cushion installed the 4 ½" tubing will get colder by a couple of degree centigrade due to the insulation properties of the N_2. The tubing will be at the same temperature as the injection CO_2; this does not pose a threat as it is planned to install S13Cr tubing in the top part of the well. The "A" annulus fluid and production casings will remain warmer which is another positive effect of installing the N_2 cushion.

The packer fluid placement technique will require review pre execution as part of the detailed well completion programme.

4. Constructability

A heavy-duty jack up is required for the workover activities due to the 400 ft [122m] this is not the water depth at the platform but more likely to be the height of the X-mas tree above the sea bed (which is key for a jack up rig) water depth. There are only a small number of jackups worldwide that can work in the water depth at Goldeneye location.

The wells will be worked over by establishing a downhole barrier to plug the well. The existing production packer and completion will be removed. A new packer will be installed along with the tubing and a tail pipe assembly stabbed into the top of the existing sand screen packer. An outline programme is presented below:

- Rig to location.
- Kill Well / set downhole barriers.
- Remove Christmas tree.
- Rig up & test BOP's (Blow Out Preventers).
- Recover downhole barriers.
- Recover existing completion tubing.
- Recover packer.
- Clean scrape 9 5/8" [245mm] casing.
- Carry out cement logging.
- Run new completion tubing.
- Set packer.
- Test tubing, annulus and SSSV.
- Install and test Christmas tree.

4.1. Reservoir isolation

In order to perform a work over and replace the existing upper completion the integrity of the well has to be managed in order to protect the surroundings from any remaining hydrocarbons in the well. This includes ensuring two effective barriers are in place. Selecting a suitable means to isolate the reservoir during the work over is a challenge due to the restrictions imposed by the internal diameter (ID) of the new proposed upper completion.

The existing upper completion has a 4.47" [113.5mm] minimum ID restriction at the mule shoe. The plug has to travel through the current completion (minimum restriction 4.47") and set in either a 5" tubing section (15 lb/ft weight [20.34Nm], 4.408" ID) or a 7" tubing section (29 lb/ft weight, 6.184" ID). The preferred and most likely position for the barrier is in the 5" section since it is more feasible to set a barrier in 5" that can travel though the current 5.5" completion.

See existing well schematic in **Error! Reference source not found.**. A list of equipment installed in the lower completion (in hole tally) is provided in Table 2-4.

The plug has to be recovered through the proposed upper completion (2.787" tubing drift) or left in the lower completion. If left in the well it must have an ID larger then than 2" to allow tools to pass for future interventions.

There are some other factors that have to be considered when sourcing a suitable plug for the well. The ability of the plug to hold the required differential pressure. The 5" setting section is only 10ft long (made up of two 5 ft pup joints). Below the 5" section there is a Formation Isolation Valve (FIV) with a restriction of 2.94" at the top, again restricting the setting length to 10 ft. The condition of this 5" section is also unknown.

Another key consideration when reviewing the barrier options was to avoid interference with the existing lower completion in order to maintain integrity for maximum injectivity. The lower completion will be left in place and it will form part of the completion design for CO_2 injection. The lower completion of the wells consists of open hole gravel packs including premium screens and pre-drilled liners. These screens have a minimum ID of 3.548". The Sump at the bottom of the well is 3 ft in length. These factors limit pushing anything down hole as an alternative to retrieving it, mainly due to the small sump size and risk of damaging or blocking the screens (reducing injectivity) but also because it is unlikely to be able to pass though the 2.94" FIV restriction.

Another important consideration is around the gravel pack sleeve below the existing sand control packer. All the plug devices discussed rely on sealing in the tubing below this sleeve. If the sleeve is leaking it will be hard to identify the source of the leak.

As well as the feasibility of suitable barriers other important factors must be considered such as; complying with industry and Shell standards, possible cost of development; the cost of the barrier itself and HSSE. A study was carried out to review the plugs available in the market and a range of possible solutions were explored. These solutions included mechanical plugs, inflatable plugs, utilising the existing formation isolation valve in the lower completion, disappearing plugs and fluid based pills such as cross linked polymers with breakers.

The FIV installed in the lower completion is a ball valve that was last actuated at the time of the original well completions i.e. 2004. The valve has been installed in the well for over 10 years and its current condition is unknown. The well is unlikely to be scaled and it did not produce any sand therefore it is possible that the valve could be an effective barrier.

Fluid based solutions such as solids free loss pill with internal breakers capable of reducing the viscosity over a set period of time and internal screen pills utilising sized calcium carbonate to bridge of inside the screens with a subsequent acid breaker have been proposed. These solutions require further engagement with the vendors to formulate the required pill. Modelling is required to understand the interaction with the gravel pack and the formation. Core flood testing is required to confirm fluid stability and any resultant formation damage (reduction of permeability around the wellbore which is the consequence of drilling, completion, injection, chemical treatment, attempted stimulation or production of that well).

The use of a tubing deployed remote operated plug in conjunction with a fluid barrier offers advantages in reduced wireline trips with high reliability. For example remote operated plugs can be deployed below the production packer as part of the tubing string. This plug can be repeatedly opened or closed by remote command and can be used to set the production packer and pressure test the tubing string.

A number of mechanical plug options have been evaluated and proposals have been received from the respective vendors. The solutions either involve a retrievable solution or a disappearing plug (glass/magnesium alloys) deployed on a lock/packer type device. All the proposed solutions require some development work from design modifications and size scaling to re-qualification. The required design modifications, retesting and qualification is achievable in the given timeframe. Suitable inflatable plugs have been identified that can be retrieved through the proposed upper completion. The use of such a plug would have to be adequately risk assessed and reviewed by an independent competent person (technical authority) before each application.

The development work around the reservoir isolation plug will require to be closely monitored and the selected components adequately tested and qualified. For this the Shell Completion and Intervention Equipment Qualification team (CERT/IERT) and QA/QC teams will be engaged.

4.2. Retrieve Upper Completion

Once the reservoir isolation is achieved and the two barrier principle is realised it is possible to remove the Christmas tree and rig up and test the well control stack (blow out preventer, BOP). Another consideration is to install a hold open sleeve in the Subsurface Safety Valve (SSSV) so that the flapper in the valve does not interfere with slickline and wireline activities.

At this stage it is possible to latch the tubing hanger with a running/pulling tool and to take an over pull to shear out the PBR. Once sheared this would allow the upper completion from the tubing hanger down to the PBR to be retrieved. The control line clamps will require to be removed from the tubing coupling, the control lines (SSSV and monitoring) would require to be spooled back at surface and the tubing connection broken out, see Figure 2-2.

If it is not possible to shear the PBR then a cutter device will have to be run in order to cut the tubing below the PBR. After a successful cut is made it would be possible to retrieve this section of tubing as described above. Following this the next step is to make a cut in the packer cut zone to release the HHC packer. The packer will then be speared and pulled to surface once the elements have relaxed (approximately 30 minutes for the slips and element system to relax.). An over pull of up to 60,000 lbs may be required to fully release the slips and element package.

This procedure has been carried out recently and the packer was retrieved successfully on first attempt, see . If the packer fails to release a second attempt to cut the packer may be made following which it is recommended to mill the inner mandrel with the final contingency to mill the packer. This would lead to some junk/swarf in the well which has potential to damage the screens or ultimately lead to that section having to be side-tracked.

Figure 4-1: HHC Packer at rotary table after being retrieved from well Pierce A10

It is essential that after retrieving the packer and tailpipe a robust clean up procedure is followed in order to clean-up the wellbore and remove any debris from the well prior to running the new completion. This requirement is heightened by the presence of any mechanical plug (e.g. FIV) that may be affected by the debris in the well.

It is also the intention to run cement bond logs and ultrasonic imaging tools to evaluate the annular cement placement and quality. At the same time casing calliper evaluation tools will be run in order to determine the exact placement depth of the new production packer.

4.3. Wellbore Clean Out

Having retrieved the existing upper completion in order to remove all debris from the well, avoid formation damage and prepare the well for installation of the new completion string a wellbore clean out operation is planned. As highlighted in the section above it is critical that a good wellbore clean out is achieved and filtered fluid is left in the well for the new upper completion to be run in.

The clean out string incorporates mechanical tools, hydraulics and specialist chemicals. The mechanical wellbore clean up tools will scrape and prepare the 9 5/8" casing for receiving the new completion and isolate the lower completion from losses during clean out operations. It is intended to set the new production packer deeper in the well in a section of casing that has been unprotected during the production life and while the wells have been left suspended. The scraper tool will be run across this section of casing and down to the existing sand control packer circulating at the maximum allowed rate. Any debris dislodged by this action can be flushed to surface or caught in a junk catcher sub included in the string. Some metallic debris can be captured with magnetic subs. If a junk catcher sub is retrieved to surface and it is full this is an indication that the clean out string should be re-run.

The clean-out string will include a temporary packer which allows the casing to be pressure tested against. Once the casing is tested clean up pills can be pumped. The pills are finally chased with clean inhibited seawater (inhibition recipe to include biocide, oxygen scavenger and corrosion inhibitor) until the required clean-up criteria is achieved usually measured in percentage of solids by volume. Table 4-1 provides a list of clean out fluids, volumes and proposed circulation rates.

Table 4-1: Proposed wellbore clean out pills and fluids.

No.	Fluid Type	Volume (bbls)	Pump Rate (bbls/min)
1	Pill A - 10% Surfactant “Wash Pill”	120	As dictated by any losses seen
2	Pill B - Hi-Vis 5% Surfactant “Catch Pill	60	As dictated by any losses seen
3	Clean Inhibited Filtered Seawater (to place pills 500 ft above MFCT in annulus)	As required	As dictated by any losses seen
4	Clean Inhibited Filtered Seawater (to achieve clean out criteria)	As required	15-20

A separate clean out trip is planned to jet the wellhead and BOP as these are areas where debris tends to accumulate.

4.4. Upper and Lower completion interface

The current design includes a tailpipe below the new production packer that stabs into the existing lower completion. There is a limitation on the length of this tailpipe for different tubing sizes indicated in Table 4-2.

Table 4-2: Tailpipe critical length.

Tubing Size	Wall Thickness (mm)	Velocity (m/s)	Critical Length (m)
2 7/8	5.5	11.0	62
3 ½	7.3	7.68	114
4 ½	6.9	4.18	226

A 4 ½" tailpipe has been selected with 4 ½" G22 dummy seals. The dummy seals will act as a baffle to the fluid from entering the annular space between the two packers (existing lower completion packer and new production packer). Using a long tailpipe down to the FIV also supports the concept to restrain the free flow of fluid into this space.

If the new upper completion were to form a perfect seal in the lower completion a closed space (trapped volume) with stagnant fluid is created between the existing lower completion packer and the new production packer. This trapped volume will originally be around 83°C once CO_2 injection is commenced the trapped fluid will cool down to around 20°C. This drop in temperature will lead to vacuum conditions. As a consequence of this the tailpipe becomes susceptible to failure under burst and the new production packer is faced with high differential pressures. This was modelled in Wellcat and the decision was made not to seal in the lower completion.

Not forming a seal in the lower completion does imply that a short section of carbon steel casing below the production packer is exposed to passive CO_2 wetting. The dummy seals and long tailpipe described above prevent this section of casing from being actively washed with corrosive fluids. It is also expected that the dry injection CO_2 will displace water from the wellbore. The fluid left between the two packers will be clean inhibited filtered seawater including corrosion inhibitor as highlighted in the previous section on wellbore clean out.

Should some CO_2 migrate past the tailpipe and dummy seals into the void space and form carbonic acid, corrosion would be expected to take place in the cavity. Given that corrosion in carbon steels relies on an ion exchange between the solution and steel surface, equilibrium (i.e. no further corrosion) will take place once iron saturation is reached and will remain in equilibrium as long as the fluids remain stagnant or replenishment rate is negligible.

As the new production packer will be installed deeper in the well across the Hidra Marl which forms part of the reservoir seal and there is at least 1000 ft of cement in the 'b' annulus above the packer corrosion of this section of the casing does not pose a threat to well integrity as it will not lead to the formation of any leak paths.

Post CO_2 injection abandonment plugs will be set around this depth thereby further removing any concerns around corrosion of this short section of casing.

4.5. Future Well Abandonment

Upon cessation of CO_2 injection, the Goldeneye injection wells will be permanently abandoned. The abandonments will be based on the following conceptual basis of design:

- The Captain and Balmoral formations are the zones which will require isolation during abandonment.
- The abandonment design currently complies with the latest industry standards and Oil & Gas UK, "Guidelines for the Suspension and Abandonment of Wells"
  - However, at the time of abandonment, the designs will be updated to comply with the prevailing legislative or industry standards.
- The Captain reservoir will be abandoned by setting two cement plugs opposite the Plenus/Hidra Marl and Rødby Shale.
- Where sufficient formation length exists, the two cement plugs will be set as a single combination plug.
- In all cases, the upper completion production packer will be removed prior to setting the abandonment plugs for plug length purposes.
- If required for plug length, the lower completion screen hanger and tubulars down to the FIV will be removed prior to setting the abandonment plugs.
- Cement bond logs will be run in each 9 ⅝" casing string to determine the position of top of cement behind the casing, and to evaluate cement quality.
  - The expectation is that top of cement and cement quality will be acceptable, and if this is confirmed, then the abandonments will be conducted by setting cement plugs inside the 9 ⅝" casing and opposite logged cement.
  - In the event that either top of cement and cement quality are deemed to be unacceptable following log evaluation, the Captain reservoir will be abandoned by section milling a window in the 9 ⅝" casing opposite the Plenus/Hidra Marl and Rødby Shale and setting a "rock-to-rock" cement plug across the window. The abandonment plug set across the Lista will provide the secondary barrier to the 9 ⅝" casing annulus in this case.
- The Balmoral formation will be abandoned using a single cement plug, unless it is suspected that CO_2 has leaked into this formation.
  - If leakage is suspected, the Balmoral formation will be abandoned using two cement plugs.
- It is currently planned to use conventional cements with additives to maintain elasticity. However, at the time of abandonment, cement slurry design will be re-evaluated to ensure that any new products developed in the intervening period are incorporated into the abandonment plug design.

The proposed abandonment concepts are discussed in the report Abandonment Concept for Injection Wells (8).

5. Well Intervention

Intervention operations will be carried out periodically on Goldeneye platform to confirm well integrity, to collect bottom hole samples and to monitor the CO_2 plume as it moves through the reservoir. The selected completion allows for well intervention by means of wireline for surveillance and potential remedial activities.

The Measurement, Monitoring and Verification (MMV) tasks outline the required intervention activities and frequency of logging. A summary of the planned intervention activities is shown in Table 5-1 below. In addition to this other unplanned activities may involve running and setting locks and plugs and standard safety valve related intervention. Some corrective measures may also require the use of slickline deployment techniques.

Table 5-1: Planned well intervention

Activity	Area of Interest	Phase	Reason
Cement bond logging	Well Integrity	Pre Injection	Baseline condition of cement bond between casing and formation
Casing integrity logging	Well Integrity	Pre Injection	Baseline condition of casing thickness
Tubing integrity logging	Well Integrity	Injection Phase – Planned yrs. 3 and 7 year 11 based on results from previous logs	Early warning of wall loss (corrosion monitoring)
Downhole sampling	CO_2 Detection (monitoring well)	Injection Phase - Planned years 7, 9, 11 and 13	Identify CO_2 concentration profile for saturation performance
Neutron porosity logging	CO_2 Conformance	Pre-injection & Injection Phase Planned years 7, 9, 11 and 13	Identify breakthrough CO_2 interval profile for saturation conformance

Wireline intervention work was carried out on Goldeneye platform in 2011 and 2012 when a number of suspension plugs were installed; see Figure 2-3 for the current well status diagrams with suspensions plugs. For the CO_2 injection phase the requirement is to leave the same deck space available as in the hydrocarbon phase in order to enable the surface rig up. The current well restriction is the formation isolation valve installed in the lower completion. This has an inner diameter (ID) of 2.94" [74.7mm]. This will determine the size of the tools to be used to access the reservoir level. The proposed tubing has an ID of 2.992"

Maximum deviation recorded in the wells is shown in is shown in Table 2-3 below:

Table 2-3. The most deviated well, GYA04, is close to the wireline deviation limit (<68 degree deviation). Issues might be presented in this well depending on tool string length.

The platform has a limited weatherdeck working area of approximately 16 m x 24 m, see Figure 5-1. This represents the predominant area available for the location of well intervention equipment. This deck is designed for a 25 kN/m^2 loading capacity over the entire area. It is important that the designated escape routes on the platform are not obstructed and that there is sufficient clear space around and between equipment packages for personnel access to operate and maintain the equipment.

For electric logging and slickline intervention activities there is sufficient room on the weather deck to accommodate all the required equipment.

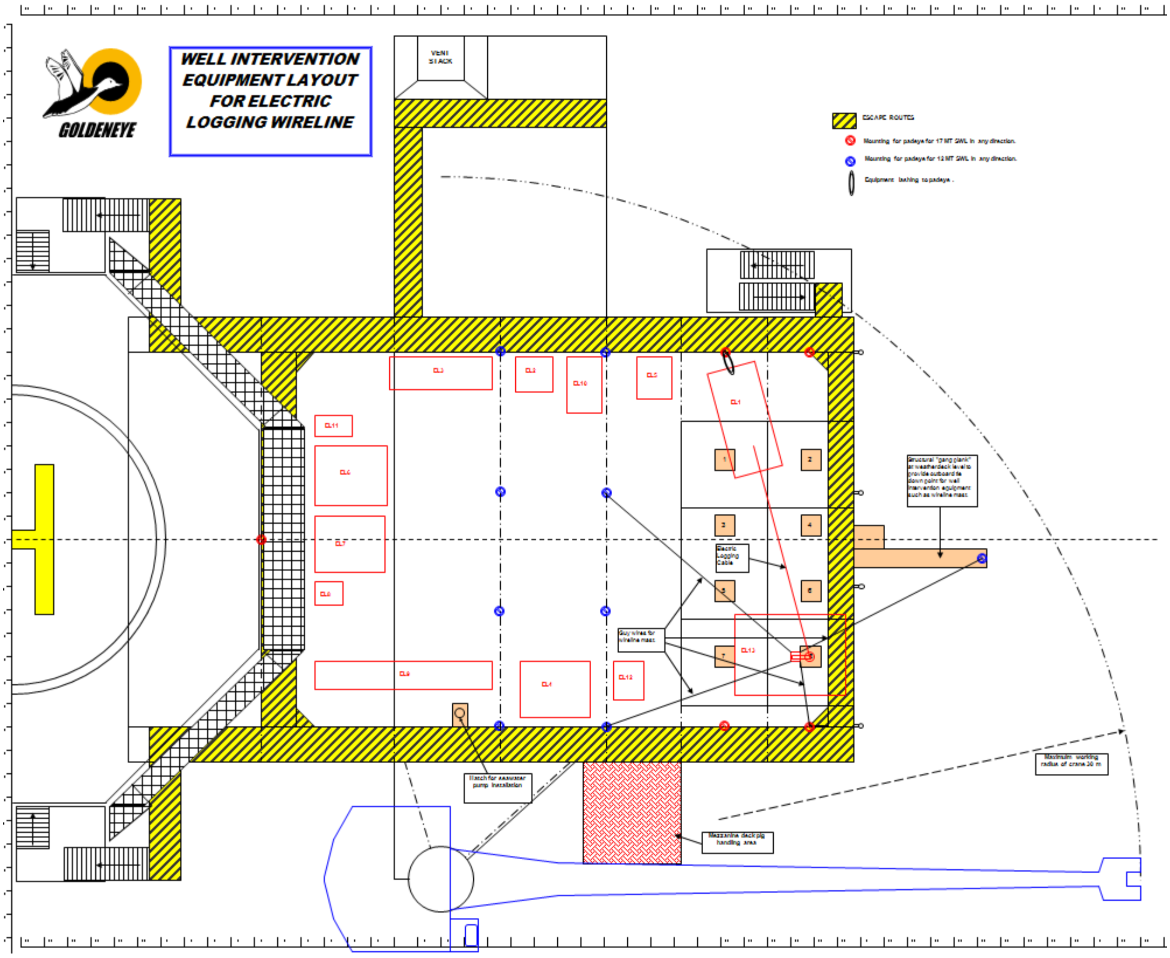


Figure 5-1: Weatherdeck layout with logging equipment

For electric logging and wireline intervention activities a wireline mast is required. A 90 ft [27.4m] mast cannot be utilised because the dimensions of the weather deck are too small to permit the required (15 m) distance from the base of the mast to the guy wire tie-down points. A 60 ft mast can be utilised, though even then there is a requirement to provide an outboard tie down point for one of the guy wires. A temporary “gang plank” structure cantilevered from the top member of the main truss frame is required for this purpose. For a coiled tubing well stimulation/pumping type of intervention followed by well clean-up using production test facilities, it has been identified that it is impossible to accommodate all the equipment on the platform and that the use of a support vessel will be required.

For acid/chemical stimulation pumping activities followed by well back-flow and clean-up, it appears just possible to accommodate all the required equipment on the weather deck. However, a further check will need to be performed when the specific requirements and equipment for a particular job are known in order to ensure that physical hook-up of all the required interconnections is possible without unacceptably obstructing access for operation and maintenance of the equipment and without encroaching on the required personnel escape routes. In the event that such a check concludes there is insufficient room, then the pumping would need to be carried out from a support vessel in a similar way as identified for a coiled tubing job.

The platform accommodation unit is designed for 12 personnel, but can this can be increased to a maximum of 22 by the use of additional drop down beds in 5 of the 6 cabins. This provision should be adequate for all envisaged rig-free well intervention jobs, though it may require some multi-tasking capability. Intervention operations by their very nature usually require that operations be carried out on a 24-hour basis. This should be considered when planning future intervention work along with additional power requirements, additional lighting, bleed down, and fluid handling facilities etc.

Once CO_2 injection commences the well will be considered to comprise of both CO_2 and hydrocarbon and hence the intervention equipment shall have to be qualified for operation in this environment. The presence of CO_2 exposes the surface rig up to the effects of JT cooling (see Figure 3-1) and explosive decompression of elastomers. It is therefore essential to ensure all components such as the lubricator, injector, stuffing box etc. are adequately designed and where necessary procedural changes are incorporated.

Concerns with utilising current intervention equipment and procedures for CO_2 injection wells:

- JT cooling effects if CO_2 in the surface rig up is allowed to expand to atmospheric pressure.
- Rapid gas decompression damage to elastomeric seals in the intervention equipment.
- Low visibility if CO_2 is released at surface.
- CO_2 can interact with water to form hydrates and acids that can plug or corrode the well. During interventions, consideration needs to be applied in pressure testing, where water based fluids are usually used to test equipment.

It is important to note that these adverse effects occur only in the highly unlikely event of a surface release of CO_2.

In order to identify risks associated with intervention in the injection wells a workshop was held with vendors, manufacturers of equipment and subject matter experts and a number of hazards were identified. The main hazards revolved around the effect of low temperatures and rapid gas decompression on equipment/environment and the compatibility of current intervention equipment/processes for the CO_2 injection wells. The hazards were analysed in detail and work required to mitigate the hazards was outlined.

In addition, key opportunities were identified that, if developed, could mitigate the majority of hazards identified and lead to intervention feasibility. These opportunities included usage of a nitrogen cushion to displace the CO_2 in the surface rig up to prevent pure CO_2 leakage and effects such as cooling and low visibility. Additional leak detection measures were recommended to prevent escalation of release scenarios. It was also recommended to review the placement of safety critical equipment and controls in relation to the CO_2 plume. As a measure to reduce leak paths it was also taken as an action to look into the option of employing a Goldeneye specific surface rig up that would incorporate sections of adequate lengths to reduce connections. Metal to metals seals with flanged connections are preferred. Finally the incorporation of a shear valve capable of cutting through all the potential tool strings and rated to the lowest temperature to enable well control under all emergency situations. It was also identified that personnel are not trained and lack experience with working on CO_2 wells. Measures and opportunities were also noted from other similar projects in

CCS/EOR and cold weather operations. Additional development work is required and this will be progressed in the detail design phase.

6. Conclusion

A Well Technical Specification has been developed from the WFS (2). This has been used to identify the technical requirements for the well design. The application of these requirements to the selected conceptual design has led to the basis for the detailed well design.

Development areas have been identified for progress during the detail design phase. These have been incorporated into a forward plan in order to mature the detailed well design.

There are no fundamental concerns with the constructability or execution of the proposed workovers and the well design can be developed to deliver the specified project requirements.

7. Bibliography

1. **PCCS-05-PT-ZW-7180-00002**. *Conceptual Completions and Well Intervention Design Report, (Key Knowledge Deliverable 11.093).* : Shell Peterhead CCS, 2014.
2. **PCCS-05-PT-ZW-7180-00005**. *Well Functional Specification, (Key knowledge Deliverable 11.098).* : Shell Peterhead CCS, 2014.
3. **PCCS-00-PT-AA-5726-00001.** *Storage Development Plan, (Key Knowledge Deliverable 11.128).* : Shell Peterhead CCS, 2015.
4. **PCCS-05-PT-ZR-7180-00002.** *Well and Reservoir Management Plan, (Key Knowledge Deliverable 11.126).* : Shell Peterhead CCS, 2015.
5. **PCCS-05-PT-ZW-7180-00004.** *Well Integrity Asssessment Report, (Key Knowledge Deliverable 11.113).* : Shell Peterhead CCS, 2013.
6. **PCCS-05-PT-ZR-7180-00003.** *Well Operation Guidelines, (Key Knowledge Deliverable 11.104).* : Shell Peterhead CCS, 2015.
7. **APEC Capacity Building in the APEC Region, Phase II.** S. Wong, 2012.
8. **PCCS-05-PT-ZW-7180-00001.** *Abandonment Concept for Injection Wells, (Key Knowledge Deliverable 11.100).* : Shell Peterhead CCS, 2014.
9. **PCCS-05-PT-ZW-7180-00003.** *Well Completion Concept Select, (Key Knowledge Deliverable 11.097).* : Shell Peterhead CCS, 2013.

8. Glossary of Terms

Term	Definition
13Cr	13 percent chrome content metallurgy
'A' annulus	Annulus between the production tubing and production casing string
AHD	Along hole depth
API	American Petroleum Institute
'B' annulus	Annulus between the production casing and intermediate casing string
Base oil	Oil with carcinogenic elements removed
BHT	Bottom Hole Temperature
BOP	Blow Out Preventer
CBL	Cement Bond Logging
CCP	Carbon Capture Plant
CCS	Carbon Capture and Storage
CFD	Computational Fluid Dynamics
CH_4	Methane
CITHP	Closed-in Tubing Head Pressure
CO_2	Carbon dioxide
CoP	Cessation of Production
CS	Casing
CTDM	Casing and Tubing Design Manual
CWI	Completion and Well Intervention
DAS	Distributed Acoustic Sensing
DCS	Distributed control system
DECC	Department of Energy and Climate Control
DFE	Drill Floor Elevation
DTS	Distributed Temperature Sensing
ED	Explosive Decompression
EOR	Enhanced Oil Recovery
ESD	Emergency Shut Down
Execute	Post FEED phase.
FEA	Finite Element Analysis
FEED	Front End Engineering & Design
FIV	Formation Isolation Valve
FWHT	Flowing Wellhead Temperature
FWV	Flow Wing Valve
H_2CO_3	Carbonic acid
H_2S	Hydrogen Sulphide
HNBR	Hydrogenated Nitrile Butadiene Rubber
HSE	Health Safety and Environment
HSN	Highly Saturated Nitrile
HSSE	Health, Safety, Security and the Environment
ID	Internal Diameter
ISO	International Standards Organisation
JT	Joule Thomson
KKD	Key Knowledge Deliverable

MFCT	Multi-function Circulating Tool
MFT	Minimum Film Forming Temperature
MMV	Measurement Monitoring and Verification
NaCl	Sodium Chloride
NPT	Non-Productive Time
NPT	National Pipe Thread
NUI	Normally Unattended Installation
OCTG	Oil Country Casing and Tubing
Operation	Operational phase of the project, post execute phase
PBR	Polished Bore Receptacle
PDG	Permanent downhole gauge
PEC	Pulsed Eddy Current
QA	Quality Assurance
QC	Quality Control
RCT	Radial Cutting Torch
ROV	Remotely Operated Vehicle
SAS	Stand-alone screens
Select	Pre-FEED phase of the project
SOR	Statement of Requirements
SSSV	Sub-surface Safety Valve
TA	Technical Authority
TD	Total Depth
TDS	Total Dissolved Solids
TOC	Top of Cement
TRSSSV	Tubing retrievable Sub Surface Safety Valve
TVD	True Vertical Depth
TVDSS	True Vertical Depth Subsea
UMV	Upper Master Valve
VSP	Vertical Seismic Profile
WFS	Well Functional Specification
WH	Wellhead
WHP	Wellhead pressure
WITS	Well integrity tests
WTS	Well Technical Specification
ppm	Parts per million

Glossary of Unit Conversions

Table 9-1: Unit Conversion Table

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

Table 0-1: Well Name Abbreviation Table

Full well name	Abbreviated well name
DTI 14/29a-A3	GYA01
DTI 14/29a-A4Z	GYA02S1
DTI 14/29a-A4	GYA02
DTI 14/29a-A5	GYA03
DTI 14/29a-A1	GYA04
DTI 14/29a-A2	GYA05

APPENDIX 1. Existing Well Schematic

Existing well schematic including the casing strings and conductor (GYA01).

WELL STATUS RECORD	FIELD:	PLATFORM: GOLDENEYE	DTI NO: 14/29a–A3	WELL NO. GYA–01

WELL TYPE:	GAS/CONDENSATE	TBG VOL TO PERFS:		SWAB:	73FT
DATE SPUDDED:	08/12/2003	ANNULUS VOLUME:	266bbls	MSL:	
FIRST COMPLETED:	14/03/2004	ANNULUS FLUID:	INHIBITED SEAWATER	KOP:	
WORKOVER DATE:		ANNULUS FLUID WT:	460pptf	HUD:	9166FT
DRILLING FLUID:	WMB	TUBING FLUID:		MAX DOGLEG:	2.89deg AT 4785FT AHBDF
MUD WEIGHT:	625pptf IN RES	TUBING WEIGHT:	29 LB/FT	MAX DEV:	36.36degAT 7536FT AHBDF
WEIGHT MATERIAL:		TUBING VOLUME:	TO FIV 318bbls	MINIMUM I.D.:	2.94" AT 8755FT AHBDF

MAASP DATA

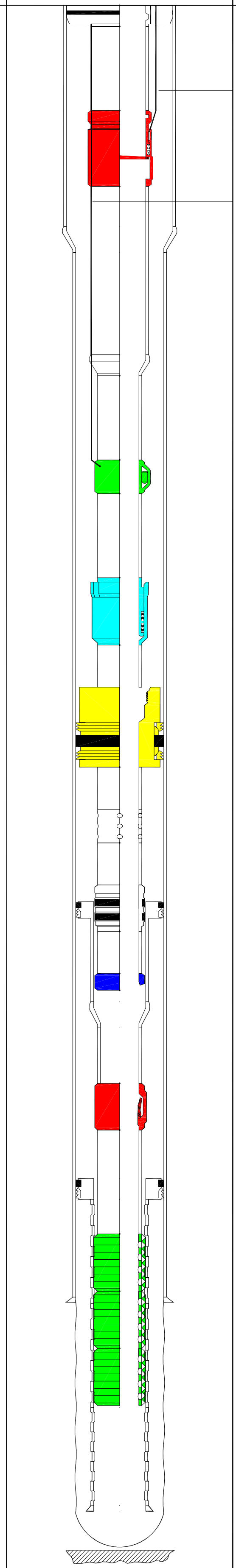
ANNULUS	MAASP (Bar)
ANNULUS "A"	3000 psi
ANNULUS "B"	329 psi
ANNULUS "C"	

WELLHEAD DATA

	MAKER	TYPE	BORE (in)	FLANGES (in)	RATING (psi)
XMAS TREE	CAMERON	MONO BORE	6 3/8"	18 3/4 FASTLOK	5000
WELLHEAD	CAMERON	SSMC STAGE 3	17.755		5000
TUBING HANGER	CAMERON	SSMC	6.169		5000

TUBING DATA

SIZE (in)	JOINTS	WT (lb/ft)	GRADE	THREAD TYPE	CLAMPS
7	203	29	13% CR L80	NK3SB	211
5 1/2	6	23	13% CR L80	NK3SB	3



DEPTH AHDBDF	DEPTH AHDBSV	DEPTH TVDBDF	INCL (°)	DESCRIPTION	MIN ID (in)	MAX OD (in)	DRIFT (in)	COMMENTS
79				CAMERON TUBING HANGER SSMC (CTL 03222)	6.169	18.356	6.059	OD 19.38" OVER SNAP RING
				TRSSSV CONTROL LINE				
2549				HALLIBURTON TRSSSV 7" SP–2 (CTL 03221)	5.875	8.41		5.875 RPT NIPPLE PROFILE
				SCHLUMBERGER PDHG CABLE				
				TUBING 7" 29 LB/FT 13% CR L80 NK3SB	6.184	7.656	6.059	OD 7.656 CONNECTION NOMINAL SIZE
8322				CROSSOVER 7" x 5 1/2" 29 x 23 LB/FT 13% CR L80 NK3SB (CTL 03223)	4.670	7.685		
				TUBING 5 1/2" 23 LB/FT 13% CR L80 NK3SB	4.670	6.150	4.545	OD 6.150 CONNECTION NOMINAL SIZE
8383				SCHLUMBERGER PDHG 5 1/2" (CTL 03224)	4.576	6.989	4.545	
				TUBING 5 1/2" 23 LB/FT 13% CR L80 NK3SB	4.670	6.150		
8443				HALLIBURTON PBR c/w CIR SUB (CTL 03225) 120K SHEAR RING – NOT SHEARED	4.577	8.175		
				TUBING 5 1/2" 23 LB/FT 13% CR L80 NK3SB	4.670	6.150		
8528				HALLIBURTON PACKER 9 5/8" HHC (REP 14637)	4.65	8.305		
				TUBING 5 1/2" 23 LB/FT 13% CR L80 NK3SB	4.670	6.150		
8651				PERFORATED PUP JOINT 5 1/2" 23 LB/FT 13% CR L80 NK3SB (CTL 03227)	4.670	6.150		
8681				BAKER SEAL ASSEMBLY (CTL 03228)	4.799	6.241		
8696				BAKER PACKER 9 5/8" SC–2R (ASSY 738–06)	6.00	8.313		
8705				BAKER RATCHETING MULE 5"	4.470	5.887		
8744				CROSSOVER 7" x 5"				
8755				SCHLUMBERGER FIV (HVF 0084)	2.94	5.500		
8831				UNIFLEX LINER HANGER				
				7" PRE–DRILLED LINER				
				BAKER SCREENS 4"	3.548	4.800		
9153				BAKER SCREEN BULL NOSE 4"				
9163				PRE DRILLED LINER SHOE 7"				
9166				TD				

REMARKS / ADDITIONAL INFORMATION

SIGNED: BILL CONNON

REVISION: 002 REASON: DATA AMENDMENT PREPARED BY: JACKIE WILSON DRAWING DATE: 11/Aug/2004

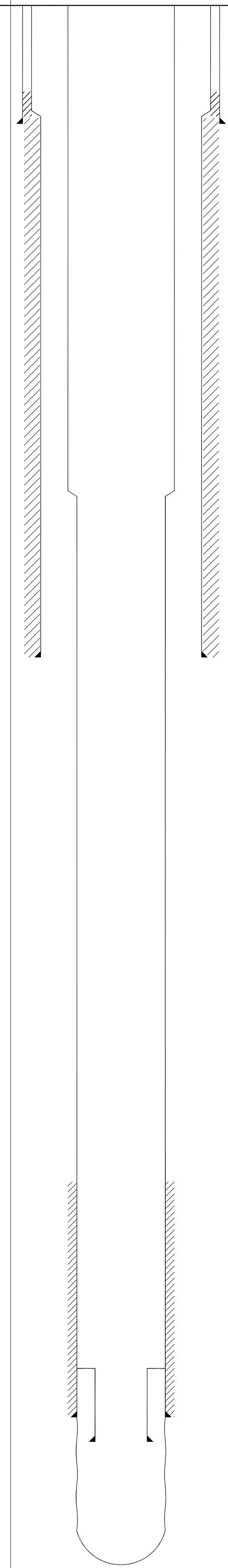
RESERVOIR: CAPTAIN SANDS	LOCATION: CNS CENTRAL GRABEN	SLOT: 01	WELL NO. GYA–01

CASING & LINER DATA

SIZE	WT (LB/FT)	GRADE	CONNECTION	TOP AHBDF	TOP TVDBDF	BOTTOM AHBDF	BOTTOM TVDBDF	TOP OF CEMENT AHBDF	TOP OF CEMENT TVDBDF	EMMG	ANNULUS FLUID	ANNULUS WEIGHT
30"	1.5" – 2"	X52	MERLIN	0	0	749.75	749.75					
20"	202.7	X80–X65	SR20 MERLINE	83	0	704	704	548	548		WBM	
13–3/8"	68	N80	DINO VAM	704	704	4155.57	4076				WBM	630
10–3/4"	55.5	L80	VAM TOP	0	0	3130	3090				OBM	560
9–5/8"	53.5	L80	VAM TOP	3130	3090	9006	8408	7506			OBM	560
7"	29	13% CR L80	NK3SB	8696	8136	9163	8544				BRINE	550

LOG DATA

RUN	LOG	TOP	BTM	DATE
17 1/2"	GAMMA RAY, GYRO AND MAG	750	4182	08/10/03
12 1/2"	D&I, GAMMA, RES	4182	9023	07/01/04
8 1/2"	D&I, GAMMA, RES	9023	9166	04/03/04



DEPTH AHDBSV	DEPTH TVDBDF	INCL (°)	CASING DIAGRAM	LITHOLOGY DIAGRAM	DEPTH AHDBDF	DEPTH TVSS
548	548		20" & 13 3/8" TOP OF CEMENT			
704	704		CASING X–OVER 20" x 13 3/8"			
749.75	749.75		30" 1.5" – 2" LB/FT X52 MERLIN			
3130	3090		CASING X–OVER 10 3/4" x 9 5/8"			
4155.57	4076		13–3/8" 68 LB/FT N80 DINO VAM			
7506			9–5/8" TOP OF CEMENT (THEORETICAL)			
8696	8136		7" TOP OF PRE–DRILLED LINER			
9006	8408		9–5/8" 53.5 LB/FT L80 VAM TOP			
9163	8544		LINER 7" 29 LB/FT 13% CR L80 NK3SB			
9166	8550		8 1/2" TD			

CHECKED BY: BILL CONNON DATE: 11/Aug/2004 CHECKED BY: DATE: