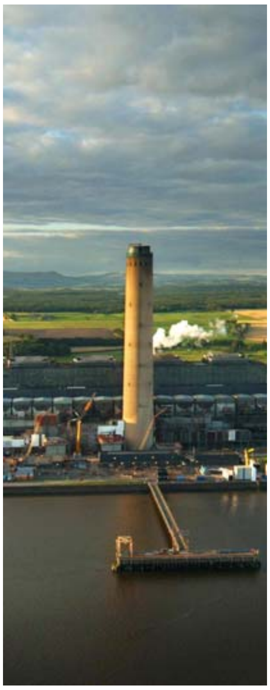

UK Carbon Capture and Storage Demonstration Competition

UKCCS - KT - S7.17 - Shell - 001

Component Concept Select

April 2011

ScottishPower CCS Consortium

SCOTTISHPOWER nationalgrid

Carbon Capture & Storage Consortium

UK Carbon Capture and Storage Demonstration Competition

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April 2011

ScottishPower CCS Consortium

ScottishPower Generation Limited
Longannet Power Station
Kincardine on Forth
Clackmannanshire
Scotland

ScottishPower Consortium UKCCS Demonstration Competition: Knowledge Transfer

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Completion Component Concept Selection

Table of Contents

Table of Figures

1. Introduction

1.1. Objective

This document seeks to define the major completion components being considered for Goldeneye CCS wells, to confirm that completion components are compatible with the injected fluids over a range of critical pressures and temperatures for the lifecycle of the well, and to identify components or parts thereof that may require further testing and qualification.

1.2. Discussion

The existing Goldeneye completions are not suitable for CO_2 injection operations. The combination of initial low reservoir pressures, circa 2,500 psi (172 bar), large bore tubing, (7.00" x 5 ½"), low arrival temperature of CO_2 at the wellhead, 2 deg C to 4 deg C (35.6 deg F to 39.2 deg F) and surface injection pressures between 45 to 115 bar (652 to 1,667 psi) make it impossible to maintain CO_2 above the saturation point when injecting CO_2 into the well.

Pressure and Temperature modelling (WEPS) suggests that injecting CO_2 into the current Goldeneye completions below the saturation point will cause a Joule Thomson effect that will cool the wellhead and upper section of tubing to around -25 deg C, to a depth of circa 2,500 ft (762 m) MD (Measure Depth). This very low temperature raises concerns with the current completion design. Of particular concern are material specification, tubing contraction, well bore freezing, and PBR (Polished Bore Receptacle) integrity.

To combat the problems associated with the Joule Thomson effect and maintain CO_2 above the saturation point, the Goldeneye wells will be worked over to remove the existing 7.00" x 5 ½" completion tubing. The wells will be re-completed using a combination of smaller tubing sizes. Using smaller bore tubing to recomplete the Goldeneye wells will introduce sufficient frictional pressure losses into the system to maintain the supplied CO_2 above the saturation line over a range of operating conditions between 34 MMscf/day (75 tonnes/hr) and 114 MMscf/day (250 tonnes/hr) at pressures between 45 to 115 bar (652 to 1,667 psi). Reference Figure1.

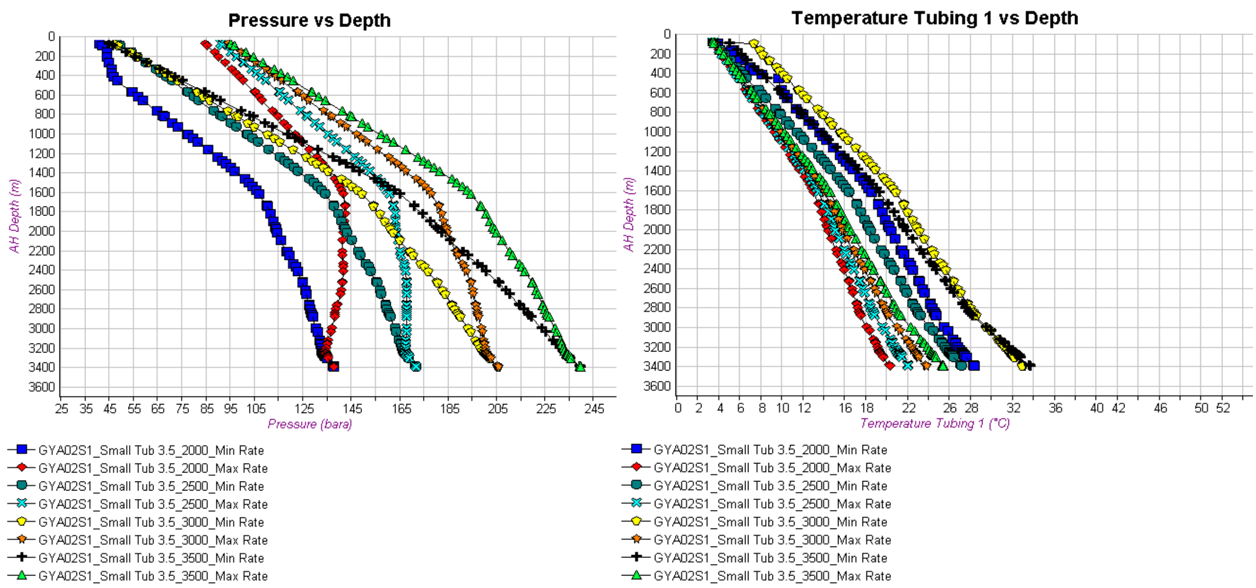


Figure 1: Pressure & Temperature vs. Depth (Steady State Conditions)

However until further pressure and temperature modelling has been completed (see document KT referenceSP.PTD60D3), the final configuration of the tubing string cannot be confirmed and final modelling cannot be completed for the same reason.

Transient pressure and temperature modelling which is fully investigated in document SP.PTD60D3 (KT reference) highlights two conditions where even with small bore tubing in the well the temperature of the injected CO_2 falls very quickly to around -14 deg C (6.8 deg F).

The first condition occurs when a well is closed in suddenly, in the case of an ESD (Emergency Shutdown) for instance. Modelling suggests that at the instant the ESD valve is closed, the frictional pressure losses that are being generated in the small bore tubing are immediately lost, allowing the CO_2 to fall below the saturation point and revert to a gaseous state. The subsequent cooling associated with the phase change will very quickly cool the CO_2 to around -14 deg C (7 deg F). However as can be seen from figure 2, the extent of the cooling is limited. The wall of the production tubing, the fluid filled tubing x 9 5/8" annulus, and the L80 production casing is relatively unaffected.

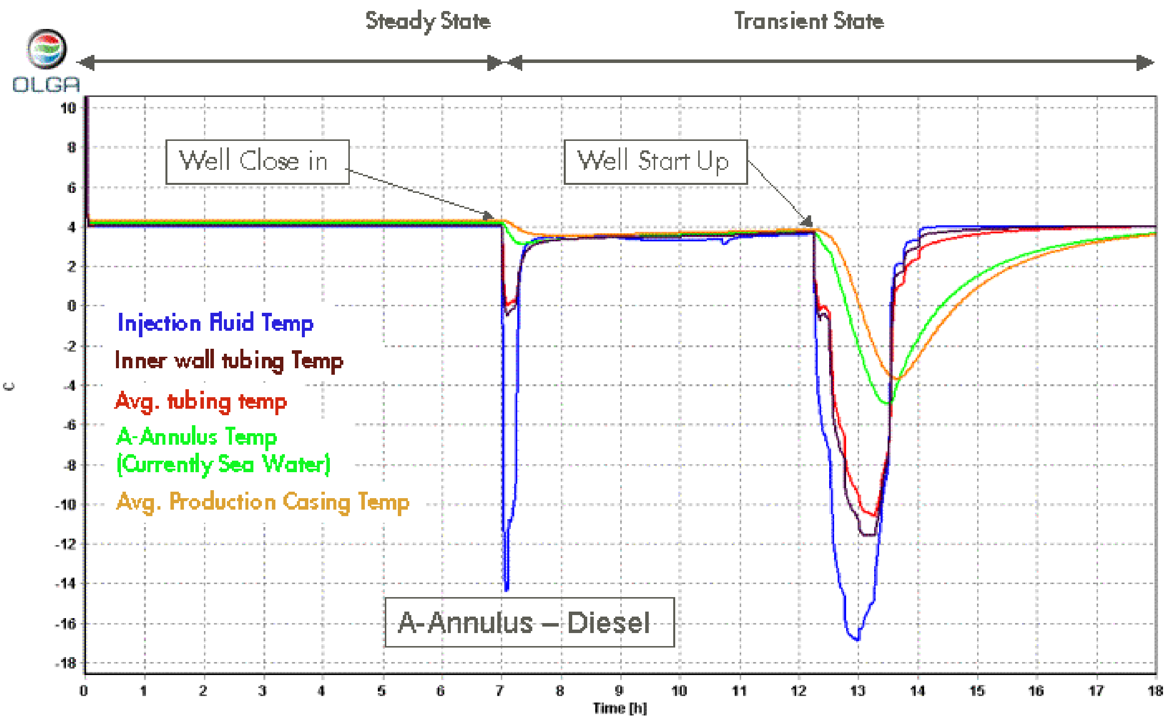


Figure 2: Transient Condition Modelling

The second condition, which is of greater concern and the worst case, occurs when starting up a well that has been closed in for a period of time after a period of steady state injection. As can be seen from Figure 2, a Joule Thomson effect over a period of two hours not only cools the CO_2 to circa -16 deg C (3.2 deg F). The temperature of the Xmas tree and surface tubing fall to -10 deg C (14 deg F), the fluid filled tubing x 9 5/8" Annulus falls to -4 deg C (25 deg F), and the 9 5/8" casing falls to circa -3 deg C (26 deg F). However as can be seen in figure 3, the temperature in the tubing at the current TRSSSV depth of 2,500 ft (762 m) as indicated by the solid gray line, is in the region of 16 deg C (41 deg F).

Worthy of note is that the Current Goldeneye Xmas tree is rated for service at Temperature class "U" (121 deg C to -18 deg C (0 deg F to 250 deg F) and that the minimum service temperature of metals (that is the temperature above which a metal will show acceptable toughness if subjected to shock loading) is -30 deg C (-22 deg F) for 13 Cr tubing and 0 deg C (32 deg F) for standard L80 carbon steel.

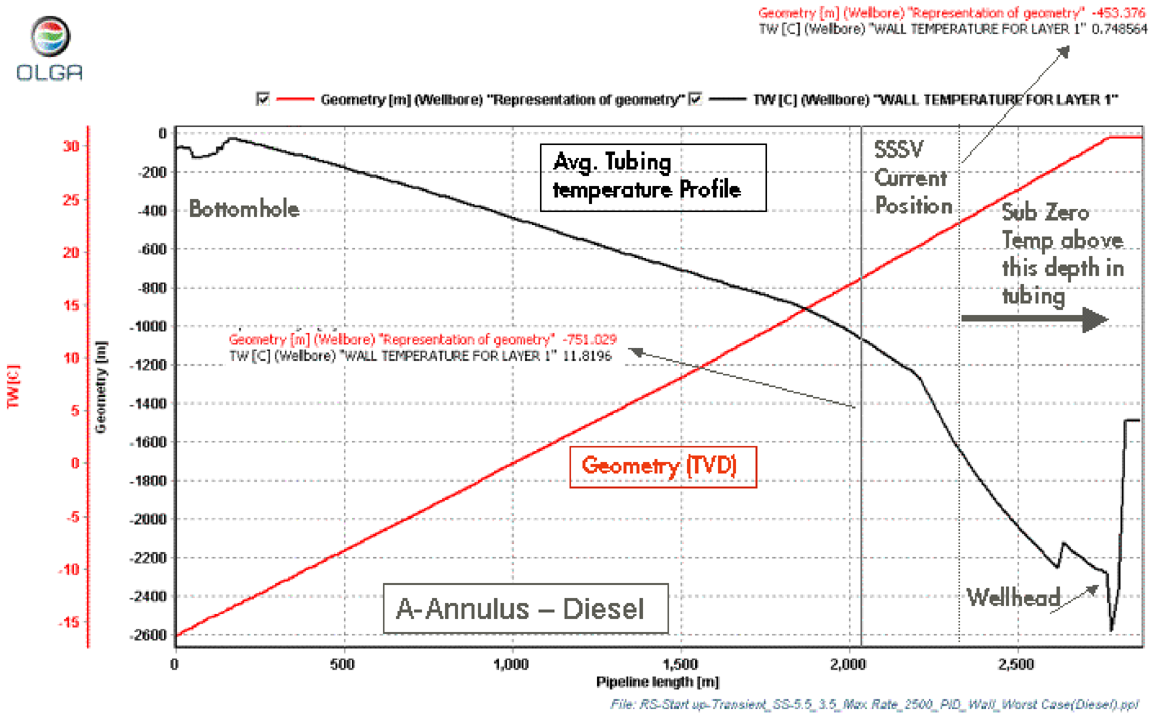


Figure 3: Temperature Profile during Startup Conditions.

1.3. Executive Summary

In lieu of the final corrosion and material assessment being issued this document makes the assumption that 13 Cr L80 material is a suitable material for the selected tubing and completion components. Initial studies suggest that dry CO_2 is not considered to be an issue with 13 Cr materials. Dry CO_2 is not corrosive even if oxygen is present in the feed gas. Even at wet conditions, 13 Cr tubing is considered to be resistant to CO_2 corrosion if oxygen is not present, although it could be susceptible to corrosion at higher temperatures and salinity. Therefore for the purpose of this document all components detailed herein are manufactured from 13 Cr material.

All elastomers currently available for downhole use allow CO_2 to permeate the material to some extent. The permeation rate of CO_2 in various elastomer materials varies but can be compared by looking at the solubility parameter of CO_2 and the elastomers of interest. The solubility parameter of commonly used oilfield elastomers ranges from 11 to 19, and CO_2 gas is 15. Tests show that the closer the materials are solubility rated i.e. CO_2 and the elastomer, the easier it is for the gas to permeate the elastomer. Therefore, the elastomers with the least solubility to CO_2 are those with solubility furthest from 15. The most commonly used oilfield elastomers are rated as follows; Nitrile from 17 to 19, epichlorohydrin from 11 to 11.5, fluorocarbon from 15 to 19. Other factors such as pressure and temperature are also considered when selecting elastomer components for use in hydrocarbon or CO_2 environments - often a balance of these parameters has to be found.

The completion components identified in this document will use Nitrile or Nitrile based HNBR (Hydrogenated Nitrile Butadiene Rubber) which have a solubility factor 17 to 19 giving good resistance to permeation by CO_2, thus reducing the risk of damage from ED (Explosive Decompression).

The following items while essentially fit for purpose within a CO_2 environment will require further qualification, calibration and or testing before they can be used in Goldeneye CCS completions.

Xmas Tree; The Goldeneye Xmas tree and wellhead is suited to CO_2 injection for the specified steady state operating parameters, but only for temperatures down to -18 deg C. Further thermal analysis will be required to verify that that the tree is suitable for repeated excursions to the low temperatures associated with a well start up where temperatures inside the Xmas tree can fall to -16 deg C (3.2 deg F). The main issue is that 410 stainless steel has a very low Charpy impact value that could generate cracking. The F6NM alternative in ES-002019-01 conforms to API-6A impact requirements.

13 Cr Tubing; No information has been found that is specific to CO_2 injection velocities inside 13 Cr tubing. However given that the density of CO_2 (900 - 950 kg/m3) is similar to that of water (1,000 kg/m3) and that modelling shows that in the dense liquid phase CO_2 will behave similarly to water. API guidelines for water injection velocities in 13 Cr tubing have been referenced.

API RP14E suggests that the maximum velocity for water injection in 13 Cr material is 4.6 m/s (15 ft/sec). However, this is considered to be a conservative estimate and some operators use 10 m/s (33 ft/sec) in carbon steel tubing and 17 m/s (55.7 ft/sec) in Duplex Stainless Steels. Given that velocities of up to 9.0 m/s (29.5 ft/sec) are forecast during CO_2 injection operations (Reference figure 4); further qualification work will be required to quantify the risk of tubing damage due to erosion corrosion and vibration.

PDG; Pressure and temperature modelling suggests that during the early stages of CO_2 injection the BHT (Bottom Hole Temperature) is likely to be in the region of 20 deg C to 35 deg C (68 to 95 deg F). Currently the pressure gauges are routinely calibrated for temperatures in the range 25 deg C to 150 deg C (65 deg F to 302 deg F). Therefore further qualification of the Downhole Pressure and Temperature measuring system will be required before it can be used on Goldeneye for CCS operations.

Elastomers; The suppliers of the G22 Seal assembly and the production packer make contradictory recommendations with regard to downhole elastomers. Nitrile sealing elements are suggested for the G22 Seal assembly while HNBR (Hydrogenated Nitrile Butadiene Rubber) is suggested for the production packer. Although both elements are essentially Nitrile based compounds further clarification will be required.

Petroline Expandable Wirefinder; Currently the only sizes of expandable wire finder available are for use inside 5 ½", 7.00" & 9 5/8" tubing/casing. Further development & qualification for use inside 3½ tubing is required.

2. Materials

To select the correct materials for use in a CO_2 injection well it is first necessary to understand the potential effects of CO_2 on the selected components. Section 2 seeks to summarise the potential methods of material degradation associated with injection of CO_2.

2.1.1. Metals

CO_2 corrosion; is nearly always a form of localised attack e.g. pits, crevice corrosion, ringworm corrosion, and guttering. The transition from affected to unaffected area is most often abrupt. Therefore very high corrosion may be observed in relatively small areas causing catastrophic failure in short periods of time. Corrosion rates can be controlled by; correct material selection, inhibition, and coatings. Corrosion resulting from the presence of CO_2 depends on the partial pressure, temperature, water content, flow velocity, H_2S, and chlorides. Each factor can change the overall susceptibility of the well to corrosion.

Water content; Dry CO_2 is not corrosive until the temperature is greater than 400 deg C (750 deg F) therefore the presence of CO_2 is of little consequence until it becomes wetted. When CO_2 and water are present a chemical reaction that produces carbonic acid takes place. $CO_2 + H_2O = H_2CO_3$. Carbonic acid lowers the pH of the well fluid, increasing the overall corrosiveness of the fluid.

CO_2 partial pressure; Increasing CO_2 partial pressures tends to produce more corrosive conditions. Laboratory testing and field data have shown that the pitting rate of carbon and low alloy steels increases with partial pressures of about 15 psia (103,000 Pa) and above. This has led to the rule of thumb that if the partial pressure is less than 3 psia the well is generally considered to be non-corrosive, but when the partial pressure is between 3 and 30 psia well corrosion is possible. When CO_2 partial pressure is greater than 30 psia the well is considered to be corrosive.

The partial pressure of CO_2 generally does not affect the corrosion resistance of most stainless steels. However increasing partial pressures of CO_2 combined with increasing chloride levels at temperatures greater than 95 deg C (200 deg F) has been shown to adversely affect martensitic stainless steels.

Velocity; A by-product of CO_2 corrosion is a scale of film. This surface film may provide a limited amount of protection from further attack but is destroyed with increasing flow. Some films or scales are actually cathodic to the base metal, so when they are damaged by flow, a galvanic couple can occur. This allows a very rapid localised attack on the metal. Stainless steels are affected most severely when the flow rate slows to stagnant conditions. Once the CO_2 flow rate has decreased significantly, the propensity for pitting increases.

Temperature; When the temperature increases the rate of chemical reaction increases. This can be beneficial in allowing films e.g. iron carbonate to form on low carbon and low alloy steels. Therefore the corrosion rate of low carbon and low alloy steels may decrease with temperature. However, the beneficial effects are limited to a temperature range between circa 200 deg F to 300 deg F (95 deg C to 150 deg C). When the temperature reaches about 300 deg F (150 deg C) the corrosion rate of carbon and low alloy steels in the presence of CO_2 and water increases dramatically.

Martensitic stainless steels and 9% Cr/1% Mo are adversely affected by increasing temperature because the protective quality of their passive film decreases with increasing temperature, resulting in higher corrosion rates. The film protection degrades when temperatures approach 150 deg C (300 deg F).

H_2S, Chlorides, and Oxygen; The presence of H_2S, and chlorides accelerates the corrosive effects of CO_2 on all metals. The presence of oxygen does not seem to affect the corrosion rates of carbon and low alloy steels. However, small amounts of oxygen have been observed to accelerate the corrosion of martensitic stainless steels such as 9% Cr/1% Mo. The presence of chlorides will increase the corrosive properties of almost all oilfield environments by destroying any protective film. The effects are usually in the form of pits, crevice corrosion, or stress corrosion cracking (SCC). When chloride presence is combined with oxygen, the tendency for both pitting and SCC increases, particularly in steel alloys with 1% to 40% nickel (e.g. austenitic stainless steels). The presence of H_2S in a CO_2 well also accentuates the problem of SCC because the lower pH created with the carbonic acid product reduces the amount of H_2S required to start the SCC process.

In summary, carbon and low alloy steels will be attacked by corrosion when the CO_2 partial pressure nears or exceeds 30 psia (207,000 Pa). The corrosion rate will increase with increasing CO_2 partial pressure and decrease with increasing temperature from 95 deg C to 150 deg C (200 deg F to 300 deg F), but will increase rapidly above 150 deg C (300 deg F). These steels are susceptible to pitting and crevice corrosion attack, so the chloride levels in the system must also be considered. Chlorides will also affect the stability of any protective film that may form.

9% Cr/1% Mo, AISI 410, and 13 Cr, these alloys perform well in a CO_2 environment at temperatures below 95 deg C (200 deg F); above that the partial pressure of CO_2 begins to have an effect and at 150 deg C (300 deg F) the effect is discernible. In a similar manner to low alloy steels, these materials are susceptible to pitting when sufficient chlorides are present

Duplex stainless steels show good resistance to CO_2 related corrosion, chlorides and SCC at temperatures below 175 deg C (350 deg F)

Nickel and Cobalt Based Alloys; alloys C-276, 825, 718, 925 etc are all very resistant to CO_2 related corrosion and chlorides at all temperatures and CO_2 partial pressures. When the Nickel content is above 40%, they are considered immune to chloride assisted SCC unless H_2S and free sulphur are also present.

2.1.2. Elastomers

Explosive Decompression (ED); Permeation of CO_2 into elastomer material followed by a rapid pressure drop can cause a condition known as Explosive De-compression. Physical damage occurs when trapped gas expands faster than it can migrate out of the elastomer. This type of damage shows up as blistering or fractures and can be a surface or an internal problem. Explosive decompression occurs in the following sequence:-

- First the gas will permeate the elastomer and will collect around any flaw site (elastomer compounds cannot be made without any microscopic voids or flaws). This gas filled micro-void becomes the site for a blister or fracture to initiate.
- Next, a rapid pressure drop (decompression) occurs outside the seal, and the higher-pressure gas that is trapped in the elastomer expands around the void area to create an internal stress. Because these micro-voids occur throughout the seals' cross section, the areas of stress created by the expanding gas can also occur throughout the cross section.
- Finally if this stress is greater than the strength of the elastomer, then a fracture or blister will appear.

If one looks at the specific factors involved in ED, a pattern of desired properties to resist damage becomes clearer. Those factors are:- the rate of decompression, the permeability of gas in the elastomer, and the strength of the elastomer compound. Temperature also has a significant influence because increasing temperature will increase permeability and simultaneously will reduce elastomer strength.

Decompression Rate; This rate, which is defined as the change in pressure with respect to time, is the factor over which the operator often has least control. For example, surface equipment elastomers could see a very rapid decompression (e.g. 1,000 psi/sec) when a gate valve is closed. On the other hand the elastomers on deep-set downhole equipment would see a much lower decompression rate (e.g. 10 psi/min) because of the slower changes in downhole pressure.

The decompression rate is the most important factor contributing to ED failure of an elastomer. When this rate can be controlled it is possible to control the release of CO_2 gas from an elastomer seal such that no damage to the seal will occur. However, because the optimum rate of decompression depends on the specific compound, it is not possible to state any absolute decompression rate for all compounds. Tests show that from 4,000 psi to 1,000 psi decompression could be rapid, but below 1,000 psi decompression must occur slowly, or damage from ED may occur.

Permeability; This is another main factor contributing to the susceptibility of elastomers to ED. All elastomers currently available for downhole use allow CO_2 to permeate the material. Permeation is defined as the solubility of the gas in an elastomer multiplied by the 'diffusibility'. The permeation rate of CO_2 in various elastomer materials varies but can be compared by looking at the solubility parameter of CO_2 and the elastomers of interest. The solubility parameter of commonly used oilfield elastomers ranges from 11 to 19, and CO_2 gas is 15. Tests show that the closer the materials are solubility rated i.e. CO_2 and an elastomer, the easier it is for the gas to permeate the elastomer. Therefore, the elastomers with the least solubility to CO_2 are those with solubility furthest from 15. The most commonly used oilfield elastomers are rated as follows; Nitrile from 17 to 19, epichlorohydrin from 11 to 11.5, and fluorocarbon from 15 to 19.

Strength; Because it is difficult to control decompression rate and because all available materials are permeable to CO_2, the only remaining method available to reduce damage from ED is to increase the elastomer physical strength. Compounds must be formulated to achieve a balance between high elongation and high modulus, properties which are normally mutually exclusive. Strength characteristics are generally related to the hardness or durometer of a compound. A harder compound normally has a higher strength than a softer compound.

In summary, care should be taken to ensure that smallest decompression rate practical is achieved in every situation. Considering permeability, either Nitrile or epichlorohydrin material proves to be least permeable to CO_2. However, because Nitrile can develop high elongations at high modulus levels and can maintain fairly high levels of those properties at higher temperatures, it should be selected in most cases. This would imply a higher durometer Nitrile compound where the combination of high physical strength and relatively low permeation will allow the Nitrile to resist high decompression rates best, without incurring damage due to ED.

Reference: P.C. Stone, SPE, B.G. Steinberg and J.E Goodson, Baker Oil Tools. Completion design for water floods and CO_2 floods.

3. Upper completion Component Selection

3.1. Xmas Tree & Wellhead

3.1.1. Discussion

In general the Goldeneye tree / wellhead combination is a robust system adopting primary metal to metal seals, which are field proven. The Xmas tree and wellhead were primarily designed for gas production, which makes them good candidates for CO_2 injection. The three main areas of concern are ED resistance, corrosion resistance and Low Temperature performance.

ED (Explosive Decompression) Resistance; The Goldeneye Xmas tree has so far 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 $CO_{2.}$

Corrosion resistance; The Goldeneye Xmas tree and wellhead system material is resistant to dry CO_2.

pH Low temperature performance; The Goldeneye Xmas tree is designed for temperature class U which is (-18 to 121 deg C); the limitation being the bonnet and the tree block, both being made from 410 stainless steel.

The 7.00" Tubing Hanger is designed for temperature Class S,T,U,V (-18 to 121 deg C).

The10 3/4" Casing Hanger is designed for temperature Class P (-18 to 82 deg C).

The 18 3/4", 3 Stage compact housing is designed for Class U (-18 to 121 deg C).

Notably the elastomers reviewed for ED resistance have a greater temperature range than those of the metallic components, as low as -50 deg C (-58 deg F) for some component parts.

The Goldeneye Xmas tree and wellhead is suited to CO_2 injection for the specified steady state operating parameters, but only for temperatures down to -18 deg C (0 deg F). However further thermal analysis will be required to verify that that the tree is suitable for repeated excursions to the low temperatures expected during transient conditions when the well is closed in, in the case of an ESD or during a prolonged cold start up when the temperature inside the Xmas tree could fall to -16 deg C (3.2 deg F). The main issue is that 410 stainless steel has a very low Charpy impact value that could generate cracking. The F6NM alternative in ES-002019-01 conforms to API-6A impact requirements.

3.1.2. Xmas tree & Compact Spool Manufacturing specification

- Wellhead : 18 3/4" 5,000 psi (345 Bar) SSMC 3 stage compact wellhead.
- Manufacturing Level: PSL3.
- Temperature Class: U API 6A (17^{th} Edition) 121 deg C to -18 deg C (0 deg F to 250 deg F).
- Wellhead Equipment: DD Low Alloy Steels.
- Annulus Equipment: DD Low Alloy Steels.
- Tree equipment: FF Stainless Steel.
- Performance Requirement: PR2

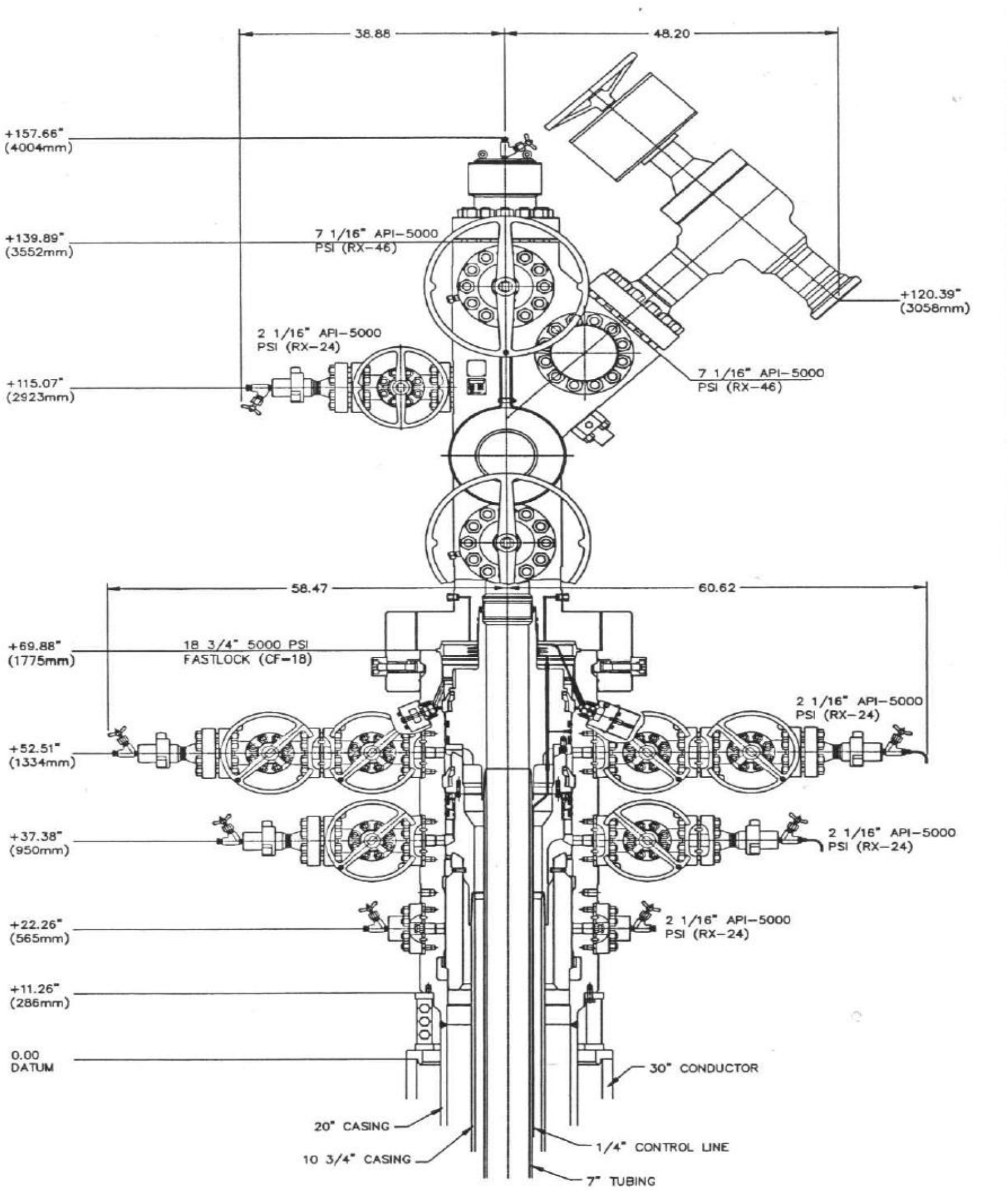


Figure 4: Cameron 6 3/8 " Xmas Tree Assembly

3.1.3. Xmas Tree Gate Valves

Cameron FLS gate valve; sealing at gate to seat, and seat to body are MM (Metal to Metal). Seal surfaces on both sides of the seats and gates are lapped to ensure gas tight sealing without the aid of sealant. Lubricant is used to limit wear, friction, and intrusion of contaminants to the valve cavity, not as an aid to sealing. One piece floating seats and a floating slab gate provide reliable performance through simplicity of operation and a minimum of sealing interfaces.

In addition to the lapped MM seal between the seats and valve body, the FLS gate valve incorporates two "V" type lip seals on the body sealing face of each seat. These outer and inner diameter lip seals are each constructed of a pressure energized non-elastomer lip seal, which is spring loaded by a finger spring. The outer and inner lip seals perform several functions.

- Contaminants are excluded from the MM sealing surfaces of the seat and body between the two seals.
- The spring-loaded feature of the seals maintains contact between the gate and seats, wiping the seal surfaces and protecting them from damage due to sand or other solid contaminants. Body cavity clearance is effectively reduced to zero while the downstream sealing function of the slab gate is retained.
- Sealing integrity is enhanced at very low differential pressures, where low bearing stresses limit the effectiveness of the MM seal.

The FLS valve is a bi-directional valve i.e. it will seal in both directions. The seal diameters and bearing areas of the FLS seats are designed to prevent trapping of pressure within the valve cavity so that the valve can be used with a fail-close actuator. Testing to PR2 has been carried out to confirm that no pressure locking or starvation occurs with the FLS valve in this situation.

The stem packing is a SLS seal, which is also a non-elastomer seal. The seal is spring loaded and pressure energized so that no longitudinal preload or precise space out is required. The SLS lip seal body is constructed of filled PTFE (Poly Tetra Fluoro Ethylene) and is spring energised with finger springs. Sealant is not required for the SLS stem seal. The seal is field proven, resistant to CO_2 and has been extensively tested with application of pressure and temperature cycles together with rotary and linear mechanical actuation cycles.

The FLS gate valve incorporates a MM stem back seat facility, which can be energized to isolate the stem packing from line pressure. The bonnet grease fitting can be used to test the integrity of the back seat:- thus the stem packing can be replaced with the valve cavity under pressure should local barrier policy allow such an operation.

The SLS stem seal is a radial squeeze seal made from inert materials. The body is made from a Teflon compound and the high deflection springs are made from a cobalt alloy. The design of the SLS stem seal allows it to be used continuously at temperatures from -18 deg C to +121 deg C (0 deg F to +250 deg F).

3.1.4. Xmas Tree Grease/Sealant

For Normal operations Cameron Valve lubricants CI-14 or TF-41 grease is recommended. These are not affected by dense phase CO_2 or CO_2 in the gas phase, and have a temperature operating envelope of -29 deg C to +121 deg C (-20 deg F to +250 deg F).

3.1.5. Tubing Hanger

The 18 3/4" x 7.00" SSMC tubing hanger has an 8 3/4" - 4 TPI (Threads Per Inch) right hand stub acme running thread top and a 7.00" 29 lb/ft NK3SB box connection down.; It is equipped with an integral LS seal and integral metal end cap seal, providing an external test capability. An integral snap ring lock down ring is capable of withstanding full-bore pressure load at 5,000 psi, (345 bar). The tubing hanger neck is prepared for a MM, SRL seal.

There are two ports machined through the tubing hanger body. These are to accommodate a continuous control line for the TRSSSV (Tubing Retrievable Sub Surface Safety Valve) and a signal cable for the PDGM (Permanent Downhole Gauge Mandrel). Both ports are fitted with ¼" NPT (National Pipe Thread) x ¼" tube male fittings top and bottom. Both ports have plugged side outlets for testing the top and bottom fittings. The design of the tubing hanger and tubing hanger running tool is such that pressure can be maintained on the TRSSSV control line during all stages of installation.

3.1.6. SSMC 3-Stage Compact Wellhead Assembly

The current gas production SSMC (Standard Snap-ring Modular Compact) 3-stage wellhead assembly consists of the following;

- A 18 3/4" 3-stage compact housing with a 18 3/4", 5,000 psi (345 bar) fast lock, CF-18 hub top x 20" Butt-weld preparation bottom, c/w 19.25" - 2 TPI left hand stub acme running thread.
- Two lower, two middle, and two upper 2 1/16" - 5,000 psi studded side outlets. All outlets have a 1.00" VR (Valve Removal) thread.
- Internal high strength landing shoulder.
- Two continuous control line exit ports each fitted with a needle valve block assembly.

The lower outlets are fitted with recessed blind flanges and VR plugs, the middle outlets ("B" Annulus) are fitted with a 2 1/16" - 5, 000 psi (345 bar) manual gate valve c/w 1502 female union on one side of the wellhead. The 1502 union has a male end cap c/w ½" NPT needle valve. The other side of the wellhead is fitted with a 2 1/16" (R-24) blind flange. Both upper outlets ("A" Annulus) are fitted with 2 1/16" - 5,000 psi (345 bar) gate valves c/w 1502 female union and end cap with ½" NPT Needle valve.

3.2. Tubing

3.2.1. Corrosion

Dense liquid phase CO_2 delivered to Goldeneye platform from Blackhill will have a water content of circa 50 ppm by volume / 20 ppm by weight. Oxygen levels will be less than 1 ppm in the gas phase, and less than 10 ppm dissolved in water. Thus CO2 corrosion is thought not to be an issue for 13 Cr materials. Dry CO_2 is not corrosive even if oxygen is present in the feed gas. Even at wet conditions, 13 Cr tubing is considered resistant to CO_2 corrosion if oxygen is not present.

3.2.2. Temperature

Transient condition modelling reference Figure 2, suggests that the worst case for low surface temperatures is during start up conditions during early field life when reservoir pressures are low. The temperature of the tubing in the upper section of the well could potentially fall to as low as -16 deg C (3.2 deg F) as dense liquid phase CO_2 being pumped through the surface choke creates a Joule Thomson effect.

The minimum service temperature of metals; that is the temperature above which a metal will show acceptable toughness if subjected to shock loading is -30 deg C (-25 deg F) for 13 Cr tubing. However there are concerns that regular excursions to low temperatures may "fatigue" the tubing to such an extent that it may eventually fail. Further qualification by a material and corrosion expert will be carried out prior to finalising the completion concept select document CW040D3.

3.2.3. Velocities

No information has been found that is specific to CO_2 injection velocities inside 13 Cr tubing. However given that the density of CO_2 (900 - 950 kg/m3) is similar to that of water (1,000 kg/m3) and that modelling shows that in the dense liquid phase CO_2 will behave in a similar manner to water, API guidelines for water injection velocities in 13 Cr tubing have been referenced.

API RP14E suggests that the maximum velocity for water injection inside 13 Cr tubing is 4.6 m/s (15 ft/sec). However, this is considered to be a conservative estimate and some Operators use 10 m/s (33 ft/sec) in carbon steel tubing and 17 m/s (55.7 ft/sec) in Duplex stainless steels. Given that velocities of up to 9.0 m/s (29.5 ft/sec) are forecast during CO_2 injection operations (Reference figure 5). Further qualification work to quantify the risk of tubing damage due to erosion corrosion and vibration will be carried out prior to finalising the completion concept select document CW040D3.

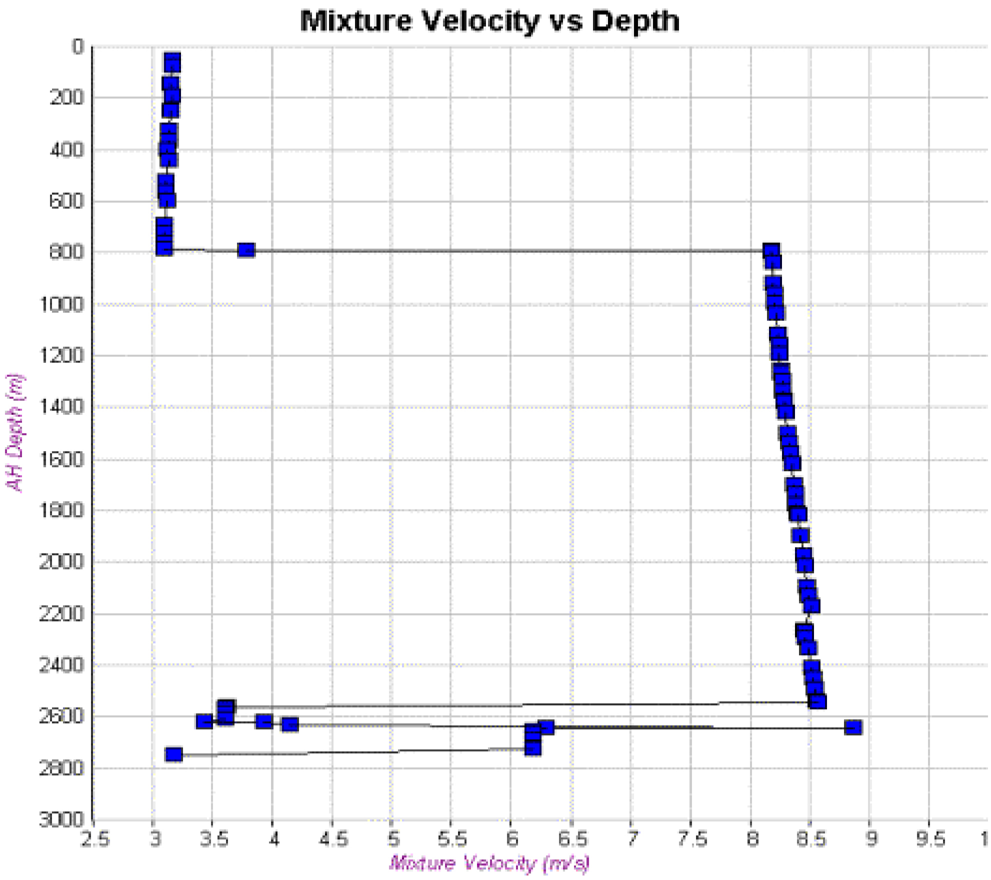


Figure 5: Velocity Vs Depth

3.3. TRSSSV

3.3.1. Discussion

A surface controlled TRSSSV (Tubing Retrievable Sub Surface Safety Valve) will be installed on all Goldeneye wells that are completed for CO_2 injection operations. The TRSSSV is required to seal off the flow of CO_2 from the well bore should surface flow control systems fail for any reason. The TRSSSV is an integral part of the platform ESD (Emergency Shut Down) system and as such is a "failsafe" valve, i.e. in the case that hydraulic control of the valve is lost the valve will automatically close. The TRSSSV shall 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. Other factors determining the final setting depth for the TRSSSV are the maximum depth that hydrates will form. The TRSSSV shall be constructed from 13 Cr L80 material, have full MM (Metal to Metal) sealing on all body connections and flapper to seat, critical flow wetted components shall be made from 925 Incoloy material. The TRSSSV shall meet the following minimum requirements for operations on a normally unmanned platform and for extended service within a CO_2 environment.

- 13 Cr material
- Qualified for operating temperatures of -7 deg C to 148 deg C (20 deg F to 300 deg F).
- Flapper type closure mechanism
- Full MM sealing of body connections
- Full MM sealing of Flapper to seat
- Premium tubing connections.
- Self-equalizing.
- Exercise profile.
- Lock open feature.
- Polished bore and lock profile to accept auxiliary low control device and or WR-SSSV.
- Be suitable for deep fail-safe setting depth.
- Maximum through bore.

A full technical specification for the selected TRSSSV is presented in Appendix 4.2. No further qualification of the TRSSSV is required for steady state or transient conditions (Ref Figure 1). However the size of the TRSSSV may change depending upon the tubing size and grade of tubing in the well.

3.4. PDGM (Permanent Downhole Gauge Mandrel)

3.4.1. Discussion

Accurate and stable pressure measurements are essential for long-term reservoir monitoring. Although it is possible to multi drop up to 4 PDG's (Permanent Downhole Gauges) on to a single encapsulated electrical cable, it is likely that only a single PDG will be installed into each of the four Goldeneye wells that are recompleted for CCS operations. PDG equipment is required to deliver highly stable pressure and temperature data during long term CO2 injection operations. The Selected

PDG performance is validated in a controlled test cell where drift stability is measured at ambient, atmospheric and simulated downhole pressure and temperature conditions. During this period gauges are also subjected to power on/off cycles and temperature cycling to simulate the forecast well conditions. Gauges are currently qualified for a 10 year life cycle and have a drift stability better than ~7,000 Pa at 82,740,000 Pa and 150 deg C (~1 deg C at 12,000 psi and 302 deg C). Completed gauge assemblies also undergo repeated shock and vibration testing to meet the environmental qualification. The long-term reliability of the selected PDG system relies on designs that include fully welded assemblies, high temperature electronic technology, metal to metal sealing and corrosion resistant alloys.

The standard NPQG (110,320,000 Pa [16,000 psi]) gauges feature a fully field-proven electrical dry-mate cable head connector. The welded cable head, which can be deployed in a Zone 1 area, protects against corrosive liquids, shock, vibration, and tensile loading. The non-welded cable head provides three independent seals, including two fully redundant metal-to-metal seals, and is fully pressure testable using a micro leak detection system. Both cable head connector options deliver significant reliability improvement over industry-standard connectors.

A detailed technical specification for the PDG system is included in Appendix 4.3. However pressure and temperature modelling suggests that during the early stages of CO2 injection the BHT (Bottom Hole Temperature) is likely to be in the region of 20 deg C to 35 deg C (68 to 95 deg F). Currently the NPQG pressure gauges are routinely calibrated for temperatures in the range 25 deg C to 150 deg C (65 deg F to 302 deg F). Therefore further calibration and qualification of the NPQG NET system will be required before it can be used on Goldeneye for CCS operations. Full Technical Specification for the Well watcher NPQG NET pressure gauge can be found in Appendix 4.4.

3.5. DTS (Distributed Temperature System)

3.5.1. Discussion

The selected Neon opto-electric monitoring cable expands the capability of the conventional well watcher PDG system by adding a fibre-optic, distributed-temperature-sensing (DTS) line to the permanent downhole cable (PDC), enabling simultaneous acquisition of pressure gauge data and distributed temperature data. The permanent Well Watcher system NPQG or NHQG gauges operate on an electrical conductor as normal. The fibre-optic line operates independently of and does not affect the reliability of the electric conductor. The Neon cable is externally identical to the PDC, and no modification to the Well Watcher system is required. A special hybrid wellhead outlet for splitting the electric and fibre-optic lines is the only nonstandard equipment requirement for using the Neon cable.

The Neon cable provides DTS temperature measurements at approximately 1.0 m [3.3 ft] intervals along the length of the fibre optic cable producing a profile of temperature effects along the injection tubing and across the mud line. The fibre optic line can be interrogated on a continuous or intermittent basis, providing well site diagnostics without interfering with injection operations. Once the data is received at surface, it can be transmitted to multiple remote locations for real time identification of time, depth, and reasons for changes in flow or injection inferred from the temperature profile. One of the primary functions of DTS on Goldeneye is to quickly identify if tubing integrity has been compromised. Figure 6 shows how the DTS identifies the source and depth of a leak by observing differences in the temperature profile of the tubing. Given that the Neon Opto-Electric cable has an operating temperature range between -20 deg C to 175 deg C (4.0 deg F to

347 deg F) and can operate at pressures up to 103,420,000 Pa (15,000 psi) no further qualification is required.

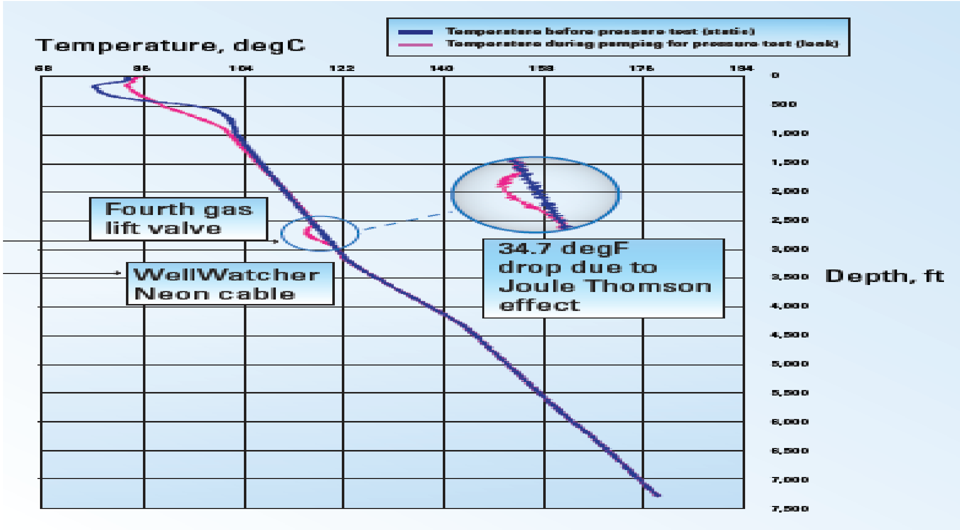


Figure 6: DTS Temperature Profile

The DTS acquisition unit has a robust database that stores all acquired data on site with local backup. In addition, various technologies are available to integrate the data into any IT environment.
A Full technical specification for the Neon opt-electric DTS system can be in Appendix 4.5.

Reference:
http://www.slb.com/services/completions/intelligent/wellwatcher/wellwatcher_dts.aspx

3.6. Production Packer

3.6.1. Discussion

A production packer has two primary functions: to seal differential pressures effectively and to anchor the packer to the casing over a large variety of operating conditions.

For CO_2 injection operations a standard AHC Hydraulically set production packer made from 13 Cr material is considered to be suitable. The packer includes a one-piece mandrel and seal bore, reducing potential leak paths. There will be no elastomer sealing elements such as a PBR (Polished Bore Receptacle) above the packer-sealing element. The packer has a one-piece case carburised, bi-directional barrel slip that affords uniform slip to casing loads, minimising damage to standard L80 and CRA (Corrosion Resistant Alloy) casing strings. The AHC packer has a triple seal multi-durometer sealing element, the middle seal being a softer durometer to cater for any casing irregularities and lower temperatures. The packer will be manufactured with premium metal-to-metal thread connections relative to the selected weight and grade of tubing.

For CO_2 injection a HNBR (Hydrogenated Nitrile Butadiene Rubber) elastomer-sealing element will be used. 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. Subsequent 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 deg C and +165 deg C (-58 deg F to +329 deg F).

The AHC packer can be set up as straight shear to release packer, or as a cut to release packer where a section of the packer mandrel is cut by chemical or mechanical means. No mandrel movement during the setting sequence makes the packer suitable for stabbing the completion tailpipe back into the existing SC-2R liner hanger packer.

Because pressure and temperature modelling work is in progress (SP.PTD60D3), it has not been possible to finalise the size of the completion tubing, and consequently the size of the production packer cannot be specified in this document. However for completeness a full technical specification for a 9 5/8" 43.5 - 53.5 lb/ft, x 5 ½" 17 lb/ft VAM Top AHC packer is included in Appendix 4.9. Until pressure, temperature and WellCat modelling is finalized, no further qualification of the production packer is required.

3.7. Trip Sub

3.7.1. Discussion

Due to the unconventional nature of the completion design, i.e. a reverse taper, small bore completion string. (Reference Appendix 1) well intervention work, and in particular fishing operations, may be compromised. For instance attempting to fish wireline or wireline tools inside 5 ½" tubing when the fishing tool has to first pass through a section of 3 ½" tubing significantly increases the risk of further complicating an already difficult operation. To cater for this scenario, trip subs that can be used in conjunction with a suitable expandable wire finder will be installed in the completion immediately below the smaller ID tubing.

("Fish" is a generic term used to describe any item of equipment that is lost or stuck in the well)

3.7.2. Wire Finder Trip Sub

The Weatherford Completion Systems, Wire finder Trip Sub (WTS) Reference Appendix 4.7 is utilized in reverse taper completion designs to facilitate the recovery of wireline or slick line lost in the well bore. The WTS is installed in place of standard tubing crossover when the tubing size is larger below a smaller tubing (e.g. 5 ½" Tubing installed below 3 ½" tubing). The WTS is designed with a 45 deg angle directly below the smaller tubing that, interfaces with the trip keys of the Weatherford Completion Systems Expandable Wire-finder during wireline fishing operations. Below the 45 deg angle is a standard ~20 deg angle that facilitates re-entry of wireline tool strings in high angle wells.

- Utilized in reverse taper completions
- Compatible with Weatherford Expandable Wire finder
- Utilized to expand and un-expand wire finder
- Available in most tubing size & grade combinations
- Any standard premium of non premium connection available

The WTS can be manufactured from any grade of material and machined with any premium thread connection. No Further qualification is required with regard to suitability of materials.A.

3.7.3. Expandable Wire Finder

Although not strictly part of the completion string, details of the Weatherford Expandable Wire finder are included for completeness, as the expandable wire finder is fundamental to the trip sub. The Weatherford Expandable Wire Finder, Reference Appendix 4.8 is for use in wells in which tubing diameters increase deeper in the well. The combination of wire finder trip sub, and expandable wire finder may significantly reduce the risk of further complicating an already difficult operation

Currently the only sizes of expandable wire finder available are for use inside 5 ½", 7.00" & 9 5/8" tubing/casing. Further development & qualification for use in a 3 ½" x 5 ½" completion string is required. ABaker G-22 Seal Assembly.

3.7.4. Discussion

A new G-22 seal assembly made from 13 Cr material will be run below the 9 5/8" production packer. The G-22 seal assembly will be stabbed back in to the original SC-2R packer and tested. Stabbing the G 22 seal assembly back in to the SC-2R packer will (once the production packer has been set) effectively seal off the section of 9 5/8" casing previously exposed to hydrocarbon flow through a perforated pup joint that was part of the original 7.00" x 5 ½" completion. Reference Appendix 4.2 original completion Schematic.

For CO2 injection the primary concern is not chemical, and 13 Cr is considered to be a suitable material for tubing and completion components in dry CO_2 conditions. Dry CO_2 is not corrosive even if oxygen is present in the feed gas. Even in wet conditions, 13 Cr tubing is considered resistant to CO_2 corrosion if oxygen is not present, although it could be susceptible to corrosion at higher temperatures and salinity.

Nitrile is considered to be the most suitable material for the sealing element on the Baker G-22 seal assembly. Nitrile shows good performance in resisting permeation by CO_2 and has good resistance to damage from (ED) Explosive Decompression, particularly when higher durometer seals are used. It is worth pointing out however, that after long-term exposure to super critical CO_2 if the seals on the G-22 seal assembly are subjected to a rapid pressure decrease, blistering will occur. However, that is unlikely to happen while seals are stabbed into the seal bore of the SC-2R liner hanger packer because the CO_2 will be above the saturation line in the dense liquid or super critical phase. Gas expansion and blistering will only occur when the pressure is dropped rapidly - as an example when pulling out of the hole. Therefore should the G-22 seal assembly be recovered during a future workover operation, as a minimum the seal assembly should be redressed with new seals even if there are no obvious signs of ED or blistering. Alternatively a complete new G-22 seal assembly should be run.

3.8. Control line fluids

3.8.1. Discussion

Transient condition monitoring software results highlight the worst-case scenario with regard to low temperature in the "A" Annulus. As can be seen in figure two, when the well is being brought back on line after being closed in for a period of two hours a Joule Thomson effect cools the CO_2 to around -16 deg C (3.2 deg F). The cooling effect is communicated to the outer extremities of the well to a certain extent. In the case of the "A" Annulus the temperature falls to around -4 deg C (25 deg F).

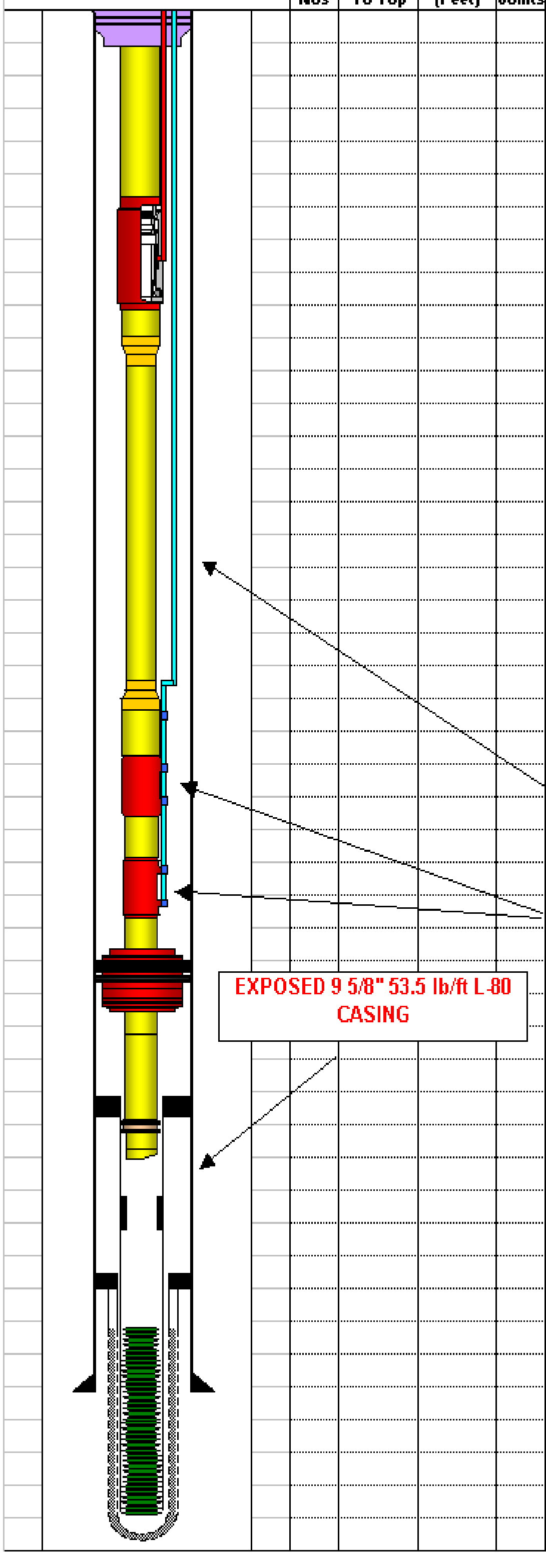
The control line fluid currently in use on Goldeneye is a synthetic hydrocarbon control fluid specifically formulated for use as the control medium in closed loop surface and subsea production control systems. The fluid incorporates all the features required for operation in a wide range of equipment, and can therefore be used as the operating medium throughout the control system including subsurface safety valve and well control areas. Castrol Brayco Micronic SV/3 has been developed and qualified under a quality management system with ISO9001: 2000 certification, and an environmental management system with ISO 14001:2004 certification for research and development. Qualification testing was carried out in accordance with ISO 13628-6 Annex C (2006 E). Castrol Brayco Micronic SV/3 is compliant with 2007 OSPAR (Oslo Paris Convention) environmental legislation.

Qualified for operation over temperature range of -40 deg C to +200 deg C (-40 deg F to +392 deg F) Castrol Brayco SV/3 has a low pour (<-50 deg C (<-58 deg F)) point making it suitable for operations in low ambient temperatures.

A full specification for Castrol Brayco Micronic SV/3 can be viewed in Appendix 4.11.

4. Appendices

4.1. Proposed Completion Schematic



Item Nos	Depth To Top	Length (Feet)	Nos Joints	Description of Item Including Part Nos & Serial Nos Where Applicable	OD (Inches)	ID (Inches)
				Tubing Hanger		
				5 1/2" Tubing		
				SCTRSSSV 5 1/2" 13cr		4.437"
				X/O 5 1/2" x 3 1/2"		
				Tubing 3 1/2" 13cr		
				X/O / Wire Finder Trip Sub 3 1/2" x 5 1/2"		
				5 1/2" Tubing		
				DTS Fiber Optic cable		
				5 1/2" PDGM		
				AHC Packer		
				5 1/2" Tubing		
				Baker SC-2R packer and G22 Seal Assy		
				Schlumberger FIV		2.94"
				Uniflex Liner hanger		
				4.00" Excluder Screens		

5. Abbreviations

API	American Petroleum Institute
BHP	Bottom Hole Pressure
CCS	Carbon, Capture and Storage
CITHP	Closed In Tubing Head Pressure
CL	Control Line.
CO_2	Carbon Dioxide
CRA	Corrosion Resistant Alloy
CT	Coiled Tubing
DTS	Distributed Temperature System
ED	Explosive Decompression
ESD	Emergency Shut Down
FLS	Company Designation
H2S	Hydrogen sulphide
HNBR	Hydrogenated Nitrile Butadiene Rubber
HSN	Highly Saturated Nitrile
ID	Internal Diameter
JT	Joule Thomson
LMGV	Lower master Gate Valve
MD	Measured Depth
MM	Metal to Metal
MMscf/day	Million standard cubic feet / day
MSL	Mean Sea Level
NPT	National Pipe Thread
OD	Outside Diameter
PBR	Polished Bore Receptacle
PDG	Permanent Downhole Gauge
PSI	Pounds per Square Inch
PSL	Product Service Level
PTFE	Poly Tetra Fluoro Ethylene
SCADA	Supervisory Control & Data Acquisition
SCC	Stress Corrosion Cracking
SLS	Company designation
SRL	Company Designation
SSMC	Standard Snap-ring Modular Compact
SW	Swab Valve
THP	Tubing Head Pressure
TPI	Threads Per Inch
TRSSSV	Tubing Retrievable Sub Surface safety Valve
TVD	True Vertical Depth
UMGV	Upper Master Gate Valve
VR	Valve Removal
WITSML	Wellsite Information Transfer Standard Markup Language
WTS	Wirefinder Trip Sub