Peterhead CCS Project

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Table of Contents

Table of Figures

List of Tables

Executive Summary

This report documents the operating range of the Carbon Dioxide (CO_2) injection wells and highlights the operational requirements required to ensure safe and reliable CO_2 injection for the Peterhead Carbon Capture and Storage project. Hydrocarbon well procedures cannot be used directly in the CO_2 wells due to the potential cooling in the top of the well, created by the Joule Thomson (JT) expansion of the fluid.

Different phases of CO_2 will exist in a well under closed-in conditions depending on reservoir pressure. The top of a well will be in gas phase whilst the bottom of the well will be in dense phase, due to low reservoir pressure (~<3500 psia, [241 bara]). This variable well condition will have an impact on the well operation guidelines.

Individual well operating envelopes have been created over the injection period. The operating envelope for a given well is driven by the philosophy/concept of operating the injected CO_2 in dense phase. As such, there will be a minimum wellhead pressure, which should be maintained under normal injection conditions. Other factors affecting the operating envelope are the maximum velocity in the tubing, maximum pressure available in the injection system and the maximum injection bottom hole pressure given by geomechanical constraints in the primary seal.

The tubing of each well is optimised based on the interactions of the different wells, the range of CO_2 rates flowing from the Peterhead capture plant and the change in conditions related to the life cycle of the project (increase in reservoir pressure). A single well will not be able to inject from the full range of CO_2 rates during the life cycle of the project due to the limited injection envelope per well. A combination of available injector wells will cover the supply 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.

Transient operations should be minimised in the wells due to the generation of low fluid temperatures in a short time period. During transient operations (well close-in and well start-up), low temperatures will be observed at the top of the well. The faster the shut-in or faster the well opening, the less the resultant temperature drop. The higher the reservoir pressure the less resultant temperature drop in the top of the well. Cold temperatures can adversely affect various well components – steels, fluids, etc. Hence operational procedures during planned transient conditions should aim to minimise this temperature drop.

It is recommended that a Nitrogen (N_2) cushion (at pressure) is used in the top of the tubing before the initial injection of CO_2 in the well. This will avoid low temperatures in the top of the well, produced by the relative low reservoir pressure before injection.

The testing of the Subsurface Safety Valve (SSSV) will be a lengthy process depending on the well condition (expected maximum of 12 hours). This time is needed to avoid generating low temperature during the CO_2 bleed-off operation, especially at the CO_2 gas-liquid phase interface. It is also recommended to limit the bleed-off pressure to comply with the temperature limitations of the SSSV.

The water content specification of the Carbon Capture and Conditioning (CCC) plant CO_2 export stream means that during normal injection hydrate formation is prevented. No continuous hydrate inhibition is required during the normal injection period in the wells. However, the presence of free water cannot be disregarded in the well due to the presence of an aquifer and water might be injected into the well during well operations. Hydrate inhibitor, methanol, should be displaced in the well especially when free water is present in the top part of the well.

1. Introduction

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

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

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

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

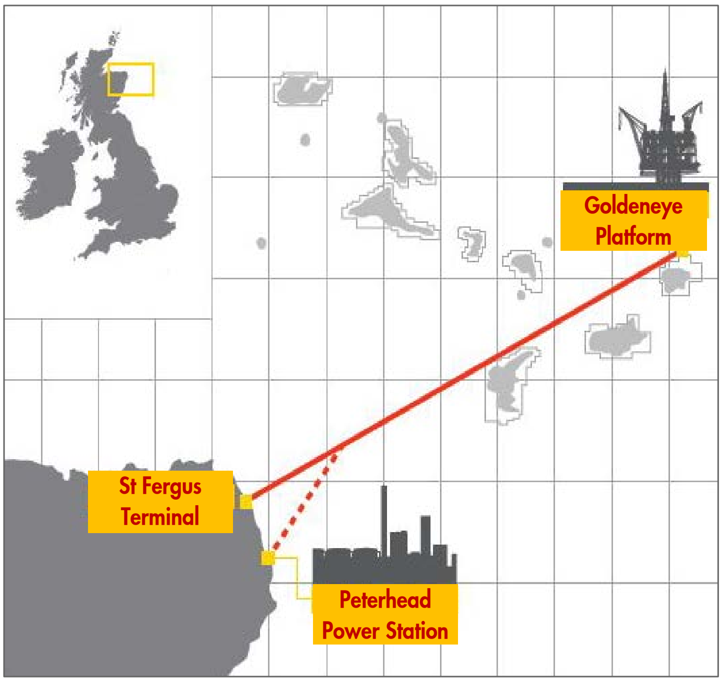


Figure 1-1: Project Location

2. Scope

This report documents the operating range of the wells and highlights operational requirements. Procedures to operate the wells will be developed during detailed design using the current guidelines.

Another objective of this report is to understand the transient well behaviour due to CO_2 injection into the Goldeneye wells and its potential implications to the well design. During CO_2 injection well transient operations need to be carefully controlled due to the risk of reaching very low fluid temperatures.

Simulations and analysis were performed to provide operating guidelines for the following transient analysis:

- Planned well transient operations for the concept of slim tubing completion using OLGA (commercial multiphase flow modelling software from Schlumberger) Simulation Software. The analysed transient effects are:
    - well close-in,
    - start-up operations, and
    - SSSV (Subsurface Safety Valve) testing.
- Initial injection of the CO_2 into the wells.
- Guidelines for unplanned conditions in the well like emergency shutdowns, stuck choke situations and re-starting the well from high tubing head pressure
- The risk of hydrate formation, guidelines to avoid hydrate plug in the well and remediation in case of forming a hydrate plug.

3. Methodology and General Considerations

For the Peterhead CCS project the Goldeneye reservoir will be used for storage of the CO_2. The CO_2 will be transported in dense phase from the Peterhead power station to the wellhead platform via the existing offshore pipeline. At the Goldeneye platform, the CO_2 will be injected into the hydrocarbon depleted reservoir via the re-completed existing wells. (Well workover requirements are documented in the Well Completion Select Report (Key Knowledge Deliverable 11.097) (1)).

3.1. Models

OLGA dynamic simulations were performed for different well conditions using the CO_2 single component module.

This module is developed for pure CO_2 and includes the CO_2 phase behaviour and properties based on the Span and Wagner equation of state.

Simulations were based on GYA-01 well. Most of the transient effects in the well happen in the top of the well (shallower than ~3000 ft depth [914 m]). The well construction is very similar in all the Goldeneye wells to that depth as such there is no justification to perform the analysis in other wells.

This well is modelled in OLGA as shown in Table 3-1 and is based on the latest well design consigned in the Well Technical Specification (Key Knowledge Deliverable 11.099) (2).

Table 3-1: GYA-01 completion details

PIPE	ID [m]	Hor L [m]	MD [m]	TVD [m]	Tubing	A-annulus	Production Casing	B-Annulus	Surface Casing	C-annulus	Conductor	Outer	Heat	T [°C]
		0.0	0.0	-24.1										
16	0.101	0.1	22.3	-46.3	4.5"	N_2	10.75"	OBM	20"	Air	30"	Air	U = 4 m/s (air)	-5.8
15	0.101	0.9	142.6	-166.7	4.5"	N_2	10.75"	OBM	20"	C	30"	Water	U = 0.5 m/s (current)	1 - 4
14	0.101	0.9	190.5	-214.6	4.5"	BO	10.75"	OBM	20"	C	-	Form	500 W/m^{2}K	4
13	0.101	4.3	317.6	-341.6	4.5"	BO	10.75"	OBM	13.375"	C	-	Form	500 W/m^{2}K	
12	0.101	22.7	479.2	-502.2	4.5"	BO	10.75"	OBM	13.375"	C	-	Form	500 W/m2K	
11	0.101	62.4	681.3	-700.4	4.5"	BO	10.75"	OBM	13.375"	C	-	Form	500 W/m^{2}K	
10	0.101	122.4	929.9	-941.6	4.5"	BO	10.75"	OBM	13.375"	C	-	Form	500 W/m^{2}K	
9	0.101	163.3	1085.8	-1092.1	4.5"	BO	9.625"	OBM	13.375"	C	-	Form	500 W/m^{2}K	
8	0.101	217.2	1242.7	-1239.3	4.5"	BO	9.625"	OBM	13.375"	C	-	Form	500 W/m^{2}K	
7	0.101	297.5	1476.2	-1458.7	4.5"	BO	9.625"	OBM	-	-	-	Form	500 W/m^{2}K	
6	0.101	320.2	1524.0	-1500.7	4.5"	BO	9.625"	OBM	-	-	-	Form	500 W/m^{2}K	
5	0.076	652.1	2263.4	-2161.5	3.5"	BO	9.625"	OBM	-	-	-	Form	500 W/m^{2}K	
4	0.076	809.9	2590.5	-2447.9	3.5"	BO	9.625"	C	-	-	-	Form	500 W/m^{2}K	
3	0.101	835.9	2645.3	-2496.2	4.5"	BO	9.625"	C	-	-	-	Form	500 W/m^{2}K	
2	0.157	871.1	2720.6	-2562.7	7"	SW	9.625"	C	-	-	-	Form	500 W/m^{2}K	
1	0.157	893.6	2769.4	-2606.0	7"	SW	-	-	-	-	-	Form	500 W/m^{2}K	83

Note: N_2: Nitrogen, BO: Base Oil, OBM: Oil Base Mud, C: Cement

Form: Formation, 500 W/m^{2}K indicates a very high source of heat at the interface between the model and the surrounding overburden.

A 96.8 mm ID (Internal Diameter) SSSV (Subsurface Safety Valve) is installed at 750 m TVD (True Vertical Depth) ~ 2500 ft AHD (Along Hole Depth). Above the SSSV the well will be completed with 4 ½" [114mm] tubing. The tubing volume between the tree and the valve is ~ 6 m^3.

Base Oil with a N_2 cushion has been used in the A-annulus.

Note that the outer boundary condition varies depending on the location. In air and water, heat exchange is modelled in OLGA based on the flow velocity and ambient temperature.

For air, a wintertime temperature of -5.8°C was used. Below the mudline 12.75 m of formation is modelled around the well. This is done using radial cells of 0.05 m, 0.1 m, 0.2 m, 0.4 m, 0.8 m, 1.6 m, 3.2 m and 6.4 m. The outer boundary condition is the geothermal temperature gradient, modelled as a vertical gradient between 4°C and 83°C.

Fluids are modelled as shown in Table 3-2.

Table 3-2: Material properties used in OLGA simulations

Fluid	Symbol	C [J/kgK]	k [W/mK]	Density [kg/m³]	Type	Viscosity [cP]
Air	Air	1047	9.15e-3	3.58	Fluid	0.19
Base oil	BO	1550	0.2	820	Fluid	0.5
Seawater	SW	4180	0.58	1001	Fluid	1
Oil-based mud	OBM	1732	0.48	1300	Fluid	20
Cement	C	2500	3	2100	Solid	-
Formation	Form	1000	2	2500	Solid	-
Steel	-	500	48	7840	Solid	-

The temperature at the wellhead is determined mostly by Joule-Thompson (JT) cooling over the wellhead choke. This choke and the pipeline upstream of the choke were not modelled separately. Instead, a mass source with a set pressure was used to supply CO_2. The pressure of this mass source was set to 120 bara and 4°C.

The reservoir was modelled using a backpressure pressure drop equation. The parameters used in the model are given in Table 3-3. This is in line with the inflow calculated in the Well Completion Select Report (1).

Table 3-3: Reservoir parameters used in backpressure model

Reservoir properties			
Permeability	850 [mD]	**Reservoir Temperature**	83 [°C]
Thickness	150 [ft]	**Reservoir Pressure,**	Res. pressure
Formation radius	3280 [ft]	**Viscosity**	From OLGA CO_2 viscosity
Well radius	215.9 [mm]		
Skin	80 [-]		

Reservoir pressure was set at 191 bara to reflect the start of injection and 265 bara to reflect the end of injection. These pressures are the lowest possible pressure at the start of injection and the original reservoir pressure in the field, which is close to the highest possible reservoir pressure at the end of 15 million tonnes of injection respectively.

At this moment, OLGA cannot simulate different fluids in the well with the CO_2 module. This module uses a specific flashing procedure (Pressure-enthalpy (P-H) flashing) which is not available for components other than CO_2. When more than a CO_2 is included in the well (for example methanol or water) then more conservative analytical analysis is carried out considering the phase behaviour of the CO_2.

3.2. Temperature Constraints

The minimum allowable temperature in the system is dictated by material limits (for the wellhead, tubing and casing) and by freezing points of fluids (in the annulus). The Well Technical Specification (2) documents the main limitations of the different components in an injector well. A summary is presented below, Table 3-4.

Table 3-4: Temperature limits at various locations

Location	Temperature Threshold [°C]	Concern
Tree	-60	Artic tree. Class 'K'. This will be a new tree
Wellhead system	-18	Brittle fracture. Not in contact with the CO_2 Part of wellhead cannot be replaced with lower temperature rated material Tubing hanger to be replaced with a -60°C limit material
Tubing above SSSV - s13Cr	-60	Material limit (brittle fracture) Increased minimum temperature threshold (~-78 °C) in 3-4 joints just above the SSSV
Casing	-40	Material limit (brittle fracture) Not in contact with the CO_2
N_2 cushion in A-annulus	< -80	Gas cushion does not pose risk to annulus integrity
Base oil in A-annulus	-60	To de defined in detail design
OBM in B-annulus	-2	Seawater freezing in the OBM
SSSV	-7	Minimum Temperature at which SSSV can be operated Current limit of the valve

Part of the wellhead is rated to -18°C. A new SSSV will retain integrity at very low temperatures. Operation is currently limited to only -7°C, hence the operating guidelines will be designed to ensure the SSSV wall temperature remains above this temperature.

3.3. Well Conditions

Throughout the report the well will be initialised using one of four initial conditions:

- *Geothermal or after injection.*
  These represent prolonged injection in which the CO_2 has cooled down the tubing and surrounding formation to the lowest possible temperature and a shut-in in which the well has heated up to the geothermal gradient (the highest possible temperature in the wellbore).
- *Low or high reservoir pressure.*
  These conditions were set at low reservoir pressure, corresponding to the start of injection, and at high reservoir pressure, corresponding to the end of injection.

This represents a thorough evaluation over the life cycle of the wells.

4. Geothermal Conditions

Different CO_2 conditions exist in a CO_2 filled well under geothermal conditions depending mainly on reservoir pressure. Since frictional loss in tubing is zero in closed in condition, tubing size is irrelevant in determining the long term Closed-in Tubing Head Pressure (CITHP). It is assumed that the CO_2 reaches equilibrium with the geothermal gradient (a slow convective current might occur in the tubing due to the difference in density of the CO_2 but this is considered negligible for these calculations). For low reservoir pressures it is not possible to back calculate the reservoir pressure from the CITHP, Figure 4-1.

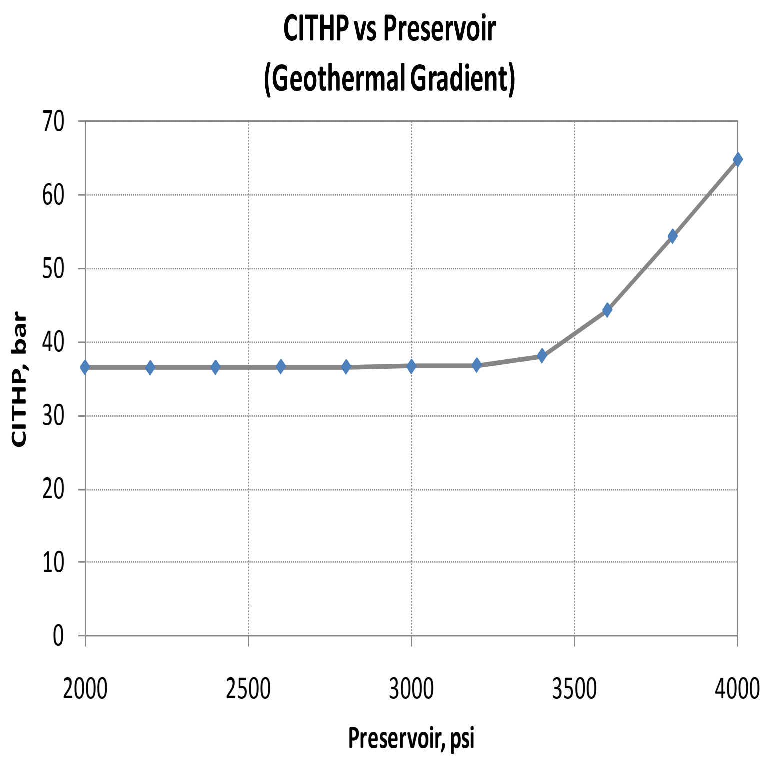


Figure 4-1: CITHP for a well filled with CO_2 at different reservoir pressures at geothermal gradient

At lower reservoir pressure a gas-liquid phase boundary is present in the well. With increasing reservoir pressure, the liquid hold-up depth decreases, i.e. liquid level rises. It can be interpreted from the graph below that when the reservoir pressure is less than ~3500 psia [241 bara], under closed-in conditions, two phases will be observed in the well. Liquid and gas interface level depends on the reservoir pressure. After a certain reservoir pressure (>3500 psia) the CO_2 in the well will be in dense phase (liquid only) and no interface is observed, Figure 4-2 (figure to the left represents the pressure profile in the well at different reservoir pressures and the right figure presents the temperature profile in the well).

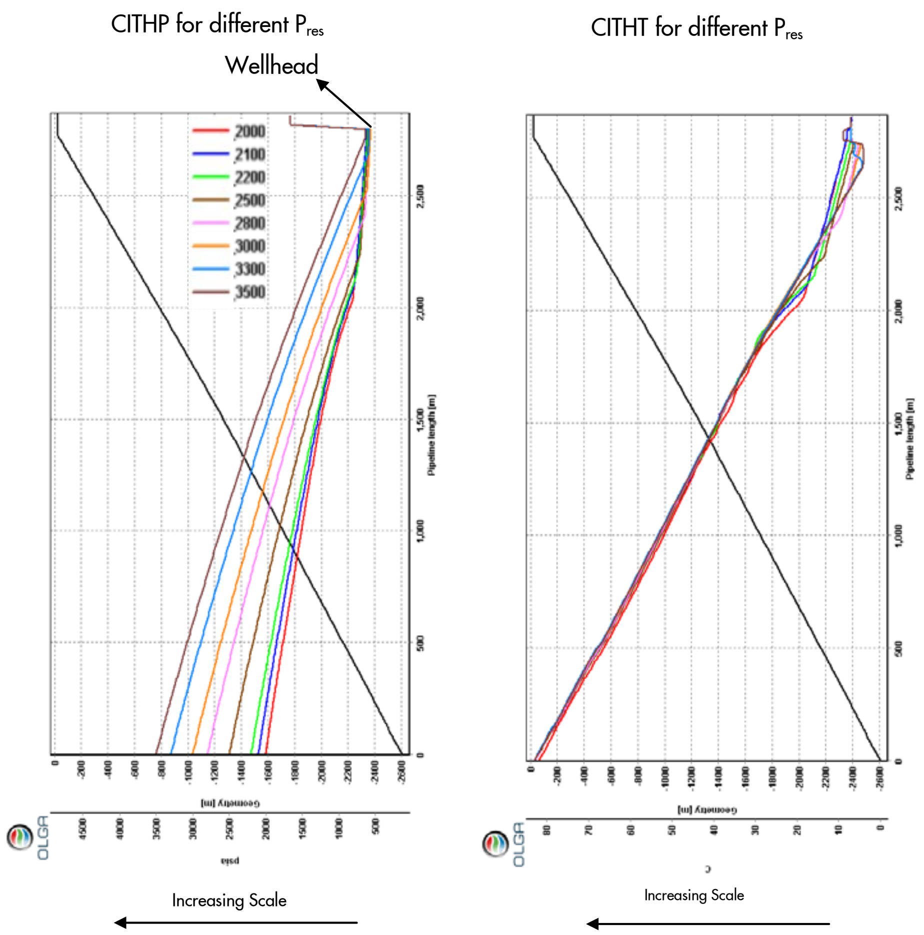


Figure 4-2: CO_2 characteristics in a well filled with CO_2 at different reservoir pressures

For the estimated reservoir pressure before injection of 2750 psia and a geothermal temperature, the Figure presents the conditions of the well, Figure 4-3.

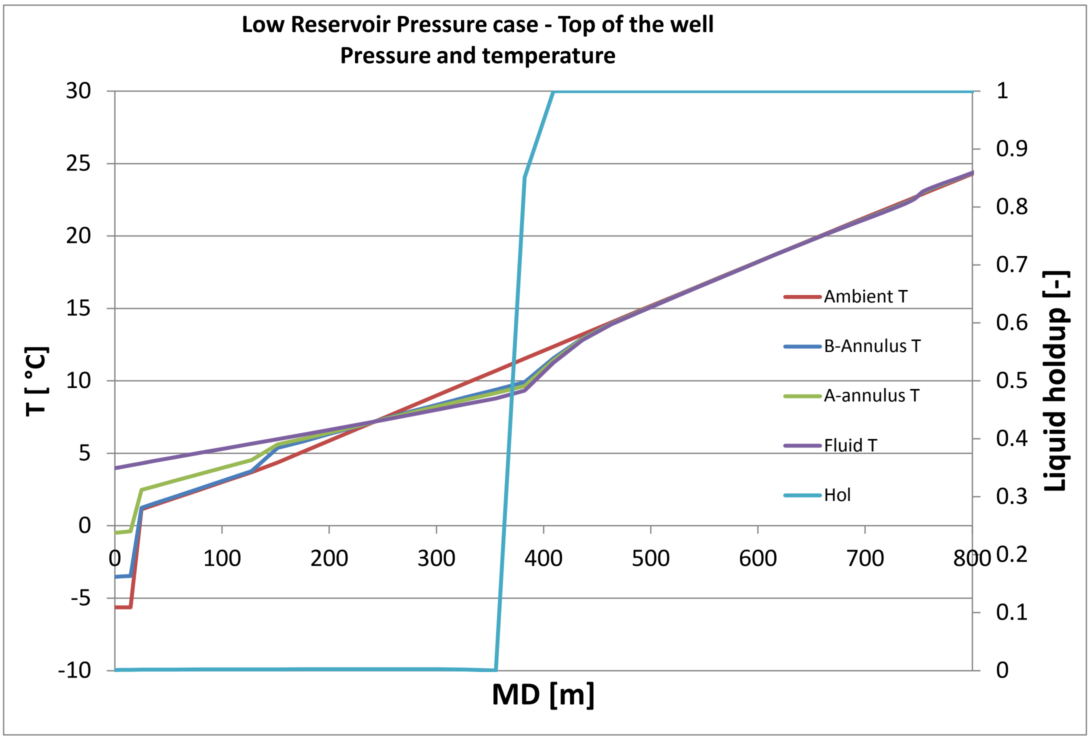


Figure 4-3: **CO_2 characteristics in a well for a well filled with CO_2 at 2750 psia (190bar) reservoir pressure at geothermal conditions**

Note that the ambient temperature near the wellhead is -5.8°C (winter design temperature). B-annulus temperature is higher (at -3.5°C) since the annuli are heated by the warmer gaseous CO_2 inside the well. From sea level down to the seabed the ambient temperature is 1-4 °C. Under these conditions heat exchange to ambient is more effective, and the B-annulus has the same temperature as the seawater. In contrast, below the mudline (below ~160 m MD) A and B annulus temperatures closely follow CO_2 temperature as long as the CO_2 is in gaseous phase. Note that natural convection in the gaseous column results in fluid temperatures somewhat above ambient at the top of the column, and somewhat below ambient at the bottom. Below the interface CO_2 temperatures and annulus temperatures follow the ambient conditions, given by a geostatic gradient. Temperature at the SSSV is 23°C.

Note that the pressure at the tubing head in a CO_2 injector well can be lower than the long term CITHP due to the density difference of the fluid at different temperatures.

5. Steady State Injection – Well Envelopes

5.1. Well Limitations

5.1.1. Tubing Head Pressure

The concept to manage the potentially low CO_2 temperatures is by keeping the CO_2 stream in liquid phase at the tubing head, by increasing the required injection tubing head pressure above the saturation line (1). This will be achieved by extra pressure drop in the well by the use of small diameter tubing creating back pressure by friction pressure loss.

Minimum tubing head pressure: 50 bara

CO_2 arrival temperature will present some minor seasonal variations throughout the year. This will be similar to the seabed temperature with some variations due to CO_2 riser expansion. For design purposes – the minimum temperature is estimated at 2.3°C, the maximum is 10.1°C. For operational purposes the expected fluctuation is between 5.3°C to 8°C.

The saturation point of the CO_2 at the maximum temperature of the CO_2 at the tree level (10.1°C) is 45.1 bara. By selecting 50 bara minimum tubing head pressure there is enough margin over the saturation conditions of the highest arrival temperature at the wellhead level, Figure 5-1.

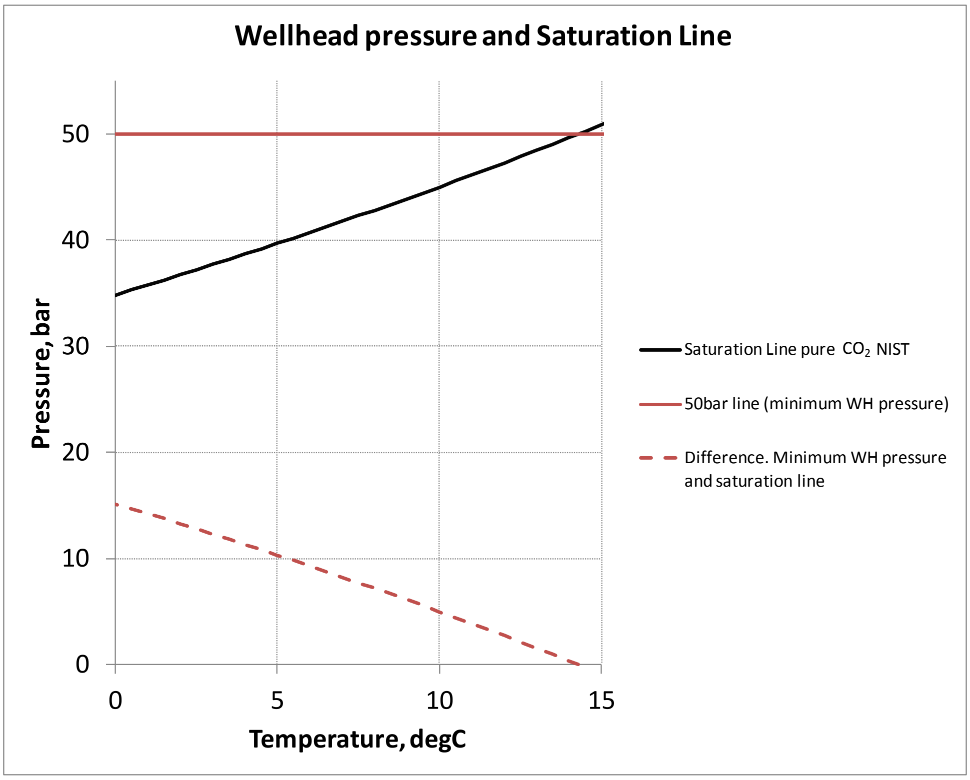


Figure 5-1: Wellhead pressure margin over the boiling/saturation curve of CO_2 for different CO_2 arrival temperatures

There should be enough difference in pressure between the minimum tubing head pressure and the CO_2 saturation pressure to avoid damage to equipment (e.g. flashing of the CO_2 may result in gas bubbles creating cavitation problems or two-phase flow). A minimum margin of ~50 psia [3.5 bara] between the minimum tubing head injection pressure and the saturation pressure is to be maintained during the injection period.

The minimum wellhead pressure can be optimised (decrease the tubing head pressure) during cold months considering the arrival temperature of the CO_2 to the platform once there is enough experience operating the system. This can be done in order to increase the operating envelope of the well reducing the minimum rate in the well. For example, assuming an arrival temperature of only 5°C (at 39.7 bara boiling pressure), then the wellhead injection pressure can be decreased from 50 bara to approximately 43 bara.

Maximum tubing head pressure: 120 bara

This is the maximum arrival pressure to the platform limited by the offshore pipeline Maximum Allowable Operating Pressure. Including pressure drops in the platform it is estimated that the maximum pressure at the wellhead will be in the order of 120 bara.

5.1.2. Maximum Velocity in the Tubing

A maximum velocity in the tubing of 12 m/s will be used in restricting the wells envelope considering vibration and erosion in the tubing under tension (1).

The 12 m/s maximum velocity is equivalent to having the following injection rates in different tubing sizes, Table 5-1:

Table 5-1: Injection rate limit for 12 m/s for different tubing diameters

Tubing Size, in	Internal Diameter, in	In-situ Injection Rate for 12 m/s, m^3/d	Surface injection rate for 12 m/s, MMscfd
4 ½"	3.958	8230	120
3 ½"	2.922	4700	68
2 ⅞"	2.441	3130	45

5.1.3. Maximum Bottom Hole Injection Pressure (BHIP)

To avoid any anomalies at the primary seal level (Rødby / Hidra formations) above the Captain formation, the maximum bottom hole injection pressure will be limited to a certain value.

The Geomechanics Summary Report (Key Knowledge Deliverable 11.115) (3) presents different considerations of thermo-elastic stresses applicable to the cold injection of CO_2 in the Goldeneye reservoir near the injection point.

Considering a 95% safety factor, the maximum bottom hole injection pressure needs to be restricted to 400 bara based on the regional minimum stress calculation. Thermal effects on the primary seal will not pose threat of fracture propagation supported by numerical and analytical calculations.

The maximum anticipated BHIP in a well injecting dense phase CO_2 is estimated at around 370 bara for the maximum available pressure at the wellhead of 120 bara injection pressure. This pressure is below the allowable maximum BHIP limit of 400 bara.

5.2. Well Interaction Principle

The number of required injector wells depends on the injection estimates (reservoir pressure and injectivity), capture plant rates, CO_2 management, monitoring requirements and life cycle risk management. The completion size for each well is selected considering the different well limitations (section 5.1), the condition and the rates of the CO_2 arriving to the platform, as follows:

- **Injection range.**

  Considers the design capacity of the capture plant 137 te/h (63 MMscfd) and turndown rate of 89.3 te/h (40 MMscfd).

  It is planned to operate the capture plant at base load (constant rate).

- **Increase in reservoir pressure.**

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

  Minimum expected reservoir pressure before CO_2 injection: 2800 psia.

  Maximum expected reservoir pressure after CO_2 injection: 3750 psia (after 15 million tonnes of injection).

  The reservoir pressures will depend on start year of injection due to the aquifer support of the reservoir.

- **Monitoring well**

  GYA-03 is planned to be a monitoring well. The well can be converted to injection once the CO_2 plume has been detected at this well. Workover operations will be carried out in this well.

- **Well Interaction**

  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 during the life cycle of the project.

  A combination of available injector wells will be able to cover the delivery rate ranges arriving to the platform. The aim is to minimise the number of wells without exceeding the overall well restrictions.

- **Overlapping of well envelopes**

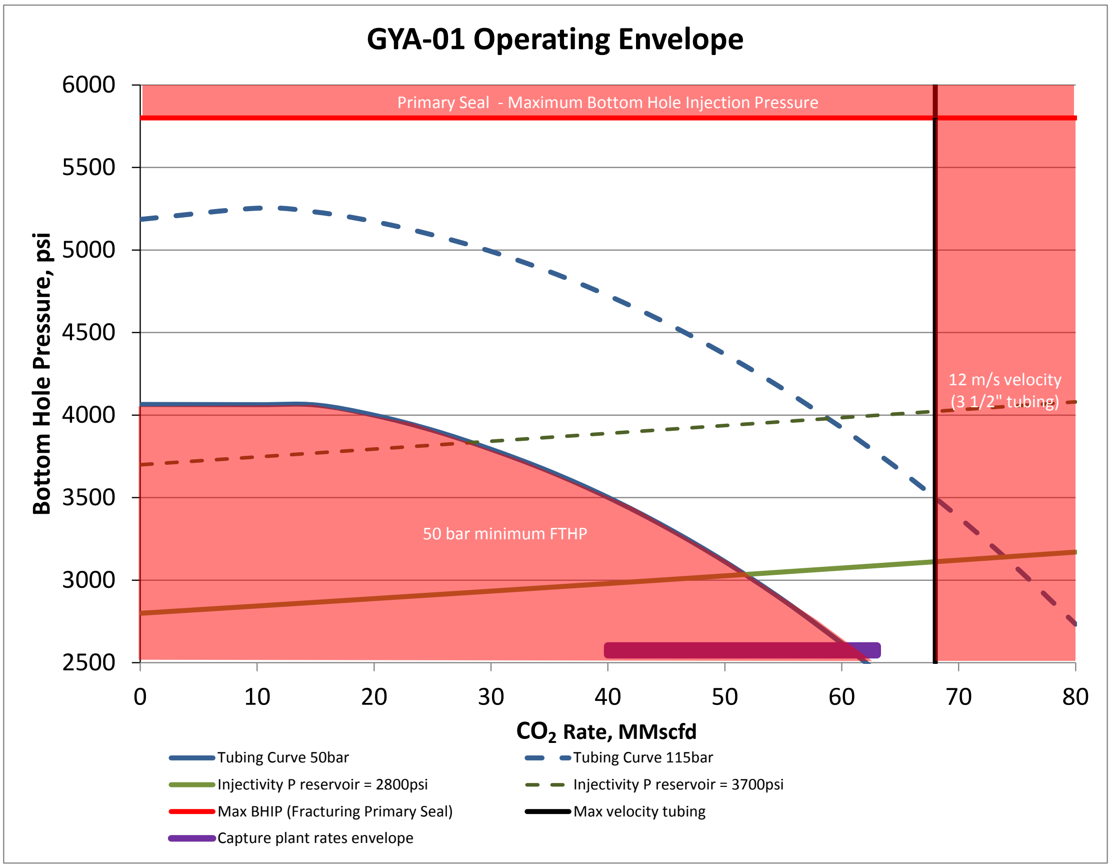
  The completion sizing also considers overlapping of well envelopes to give flexibility and redundancy in the system for a given CO_2 delivery rate. At a given arrival rate, different combinations will add flexibility to the system.

5.3. Operating Envelope per Well

The following well envelopes (Figure 5-2, Figure 5-3 and Figure 5-4) have been generated considering the well limitations and the planned conditions of the reservoir, injectivity and capture plant delivery rates.

Notes on the Well Operating Envelopes (Figure 5-2, Figure 5-3 and Figure 5-4):

- The Well Operating envelopes were generated for the combined 4 1/2" and 3 1/2" string. The crossover point is at different depths in the wells.
- Injectivity P reservoir curves represent the expected injectivity at the reservoir. For a rate= 0 then is equal to the reservoir pressure and for a rate x then a DP is required to be able to inject hence the bottom hole injection pressure is not horizontal for different rates
- Two graphs per well are included representing the same information in different units. The envelopes is used for facilities and subsurface disciplines where more familiar units are represented



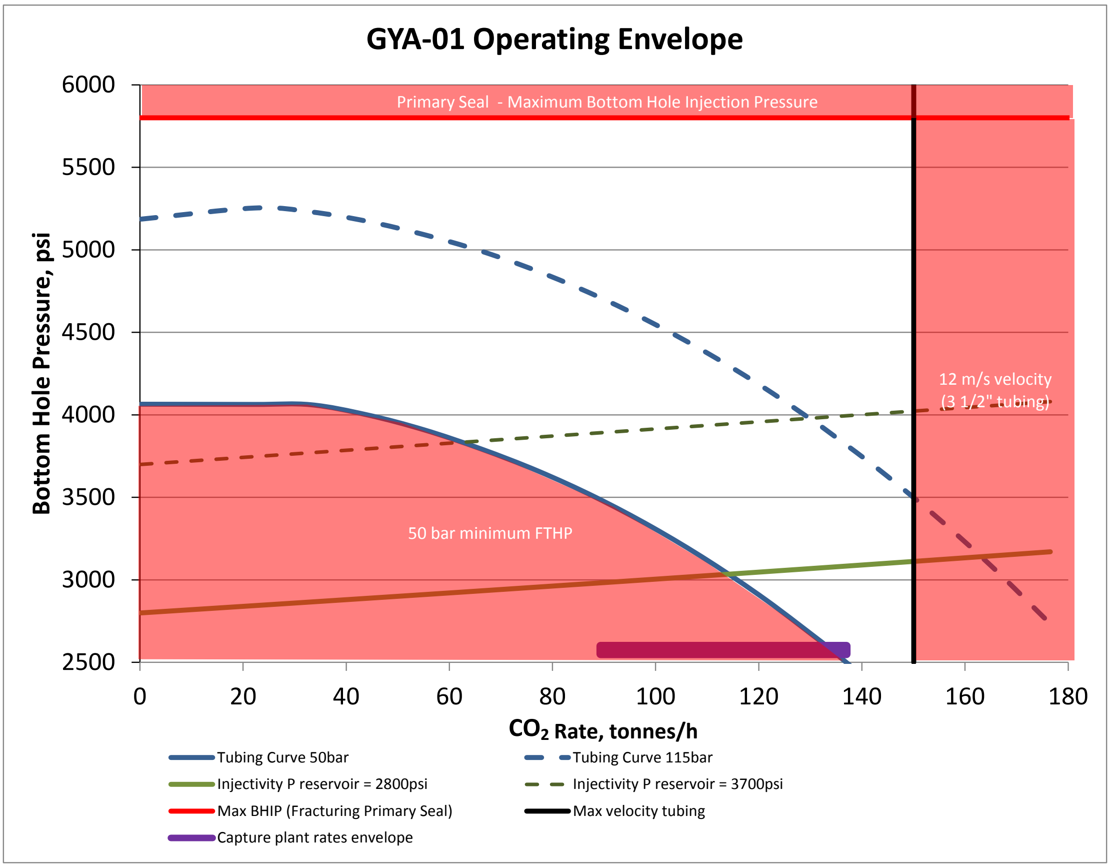
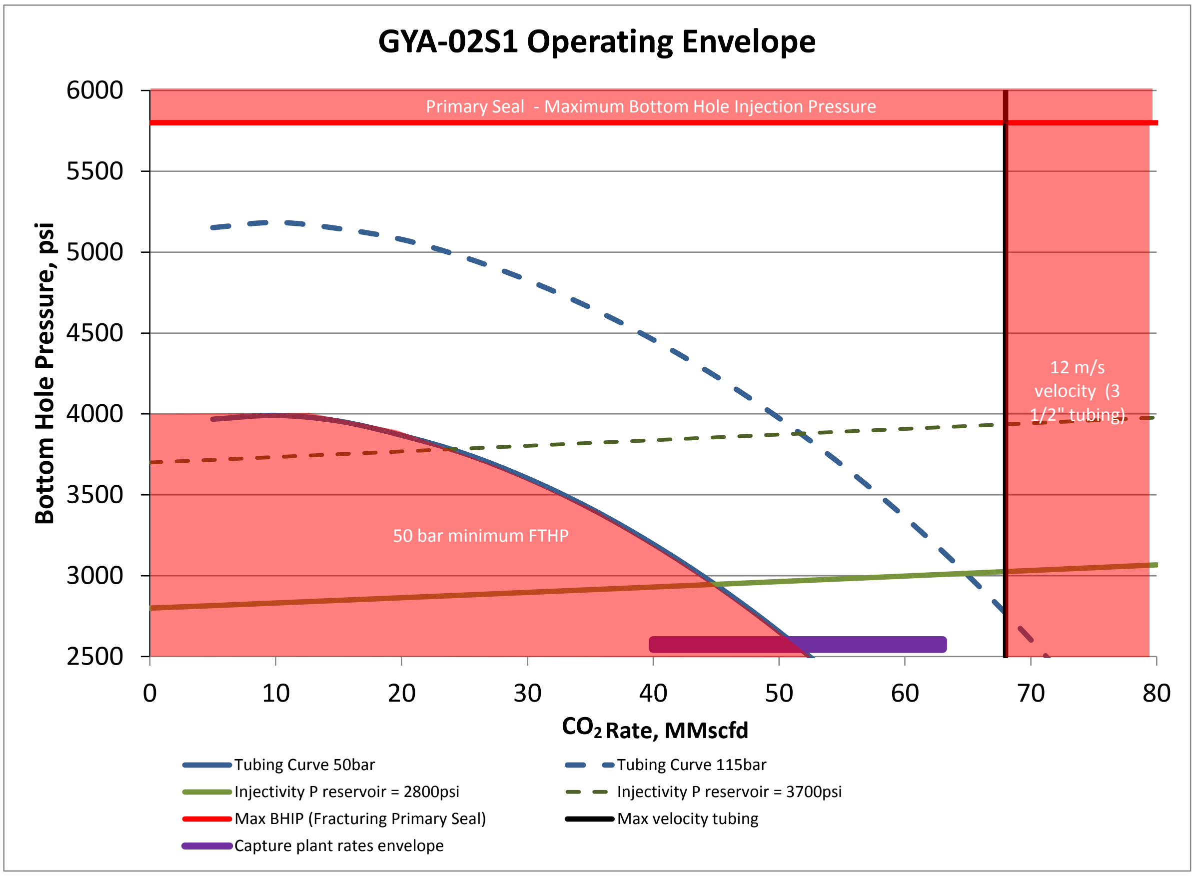


Figure 5-2: GYA-01 – Well Operating envelope under injection conditions



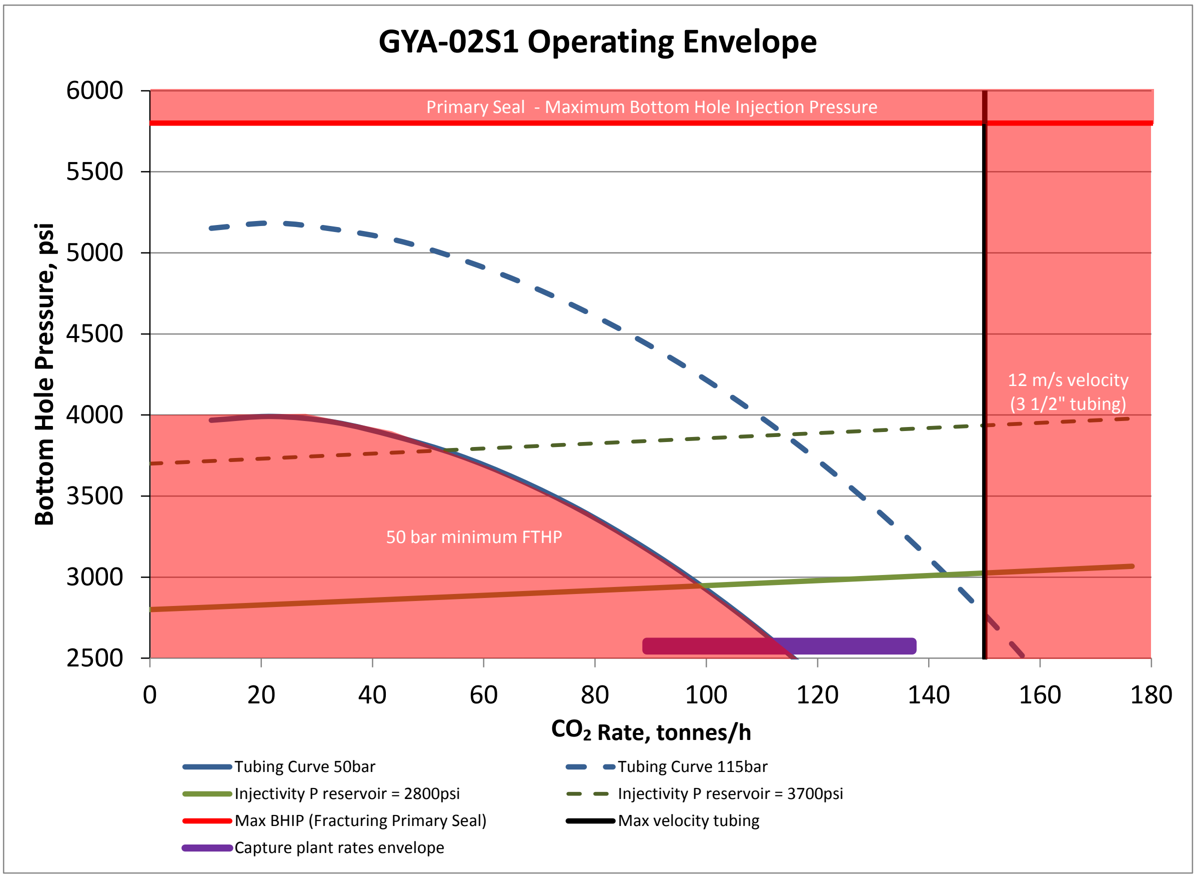
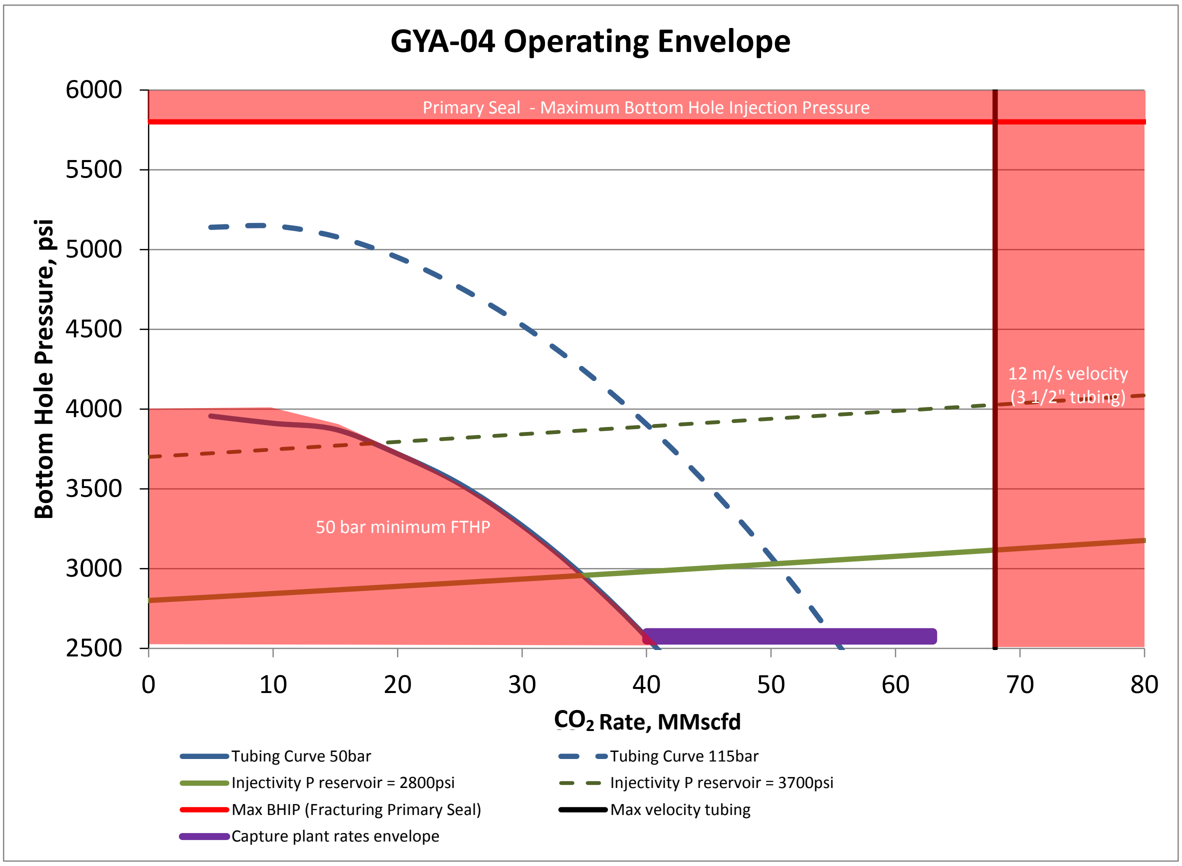


Figure 5-3: GYA-02S1 - Well operating envelope under injection conditions



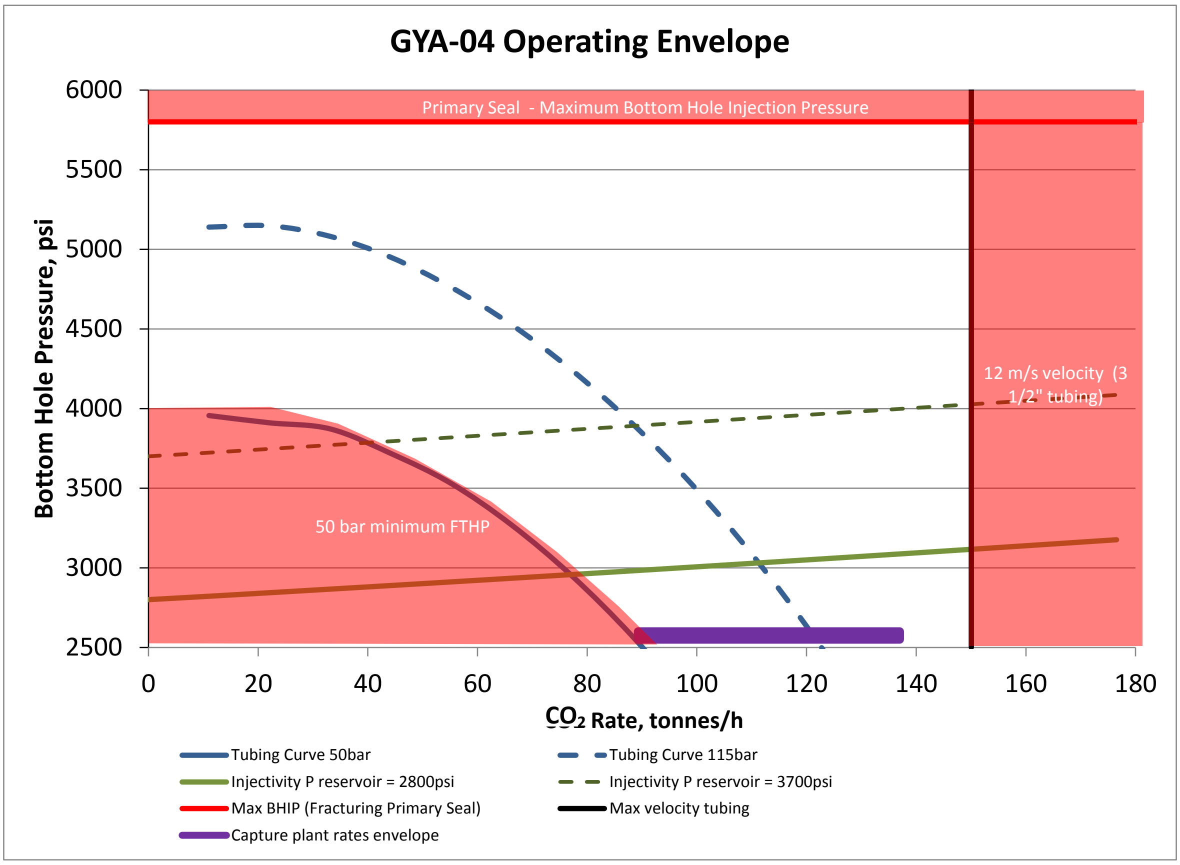


Figure 5-4: GYA-04 - Well operating envelope under injection conditions

Further remarks to the well envelopes presented above:

- GYA-04 is the smallest injector due to:
  - Longest well.
  - Shortest screens.
  - Likely to use this well in years 10-15 for injection simultaneously injecting with other well.
- GYA-01 is selected as the biggest well due to:
  - Small deviation.
  - Reasonable screens.
  - Good position in the reservoir.
- GYA-02S1 is designed to cover the range in between GYA-04 and GYA-01.
- GYA-03 is the monitor well.

5.4. Well Combinations

The combination of the different wells at varying reservoir pressures and including the individual well limitations discussed previously can be qualitatively observed in Figure 5-5.

The green horizontal bars represent individual operating envelopes per well. It represents the injection rate at the minimum and the maximum wellhead pressure. The purple horizontal bars represent the injection rate of the combination of two wells. It is done for different reservoir pressures. The vertical bars represent different injection rates. The red bar is the minimum injection rate of 40 MMscfd, and the orange bar is the maximum capacity of the capture plant 63 MMscfd). The dark grey bar is considered the normal operating rate of the capture plant.

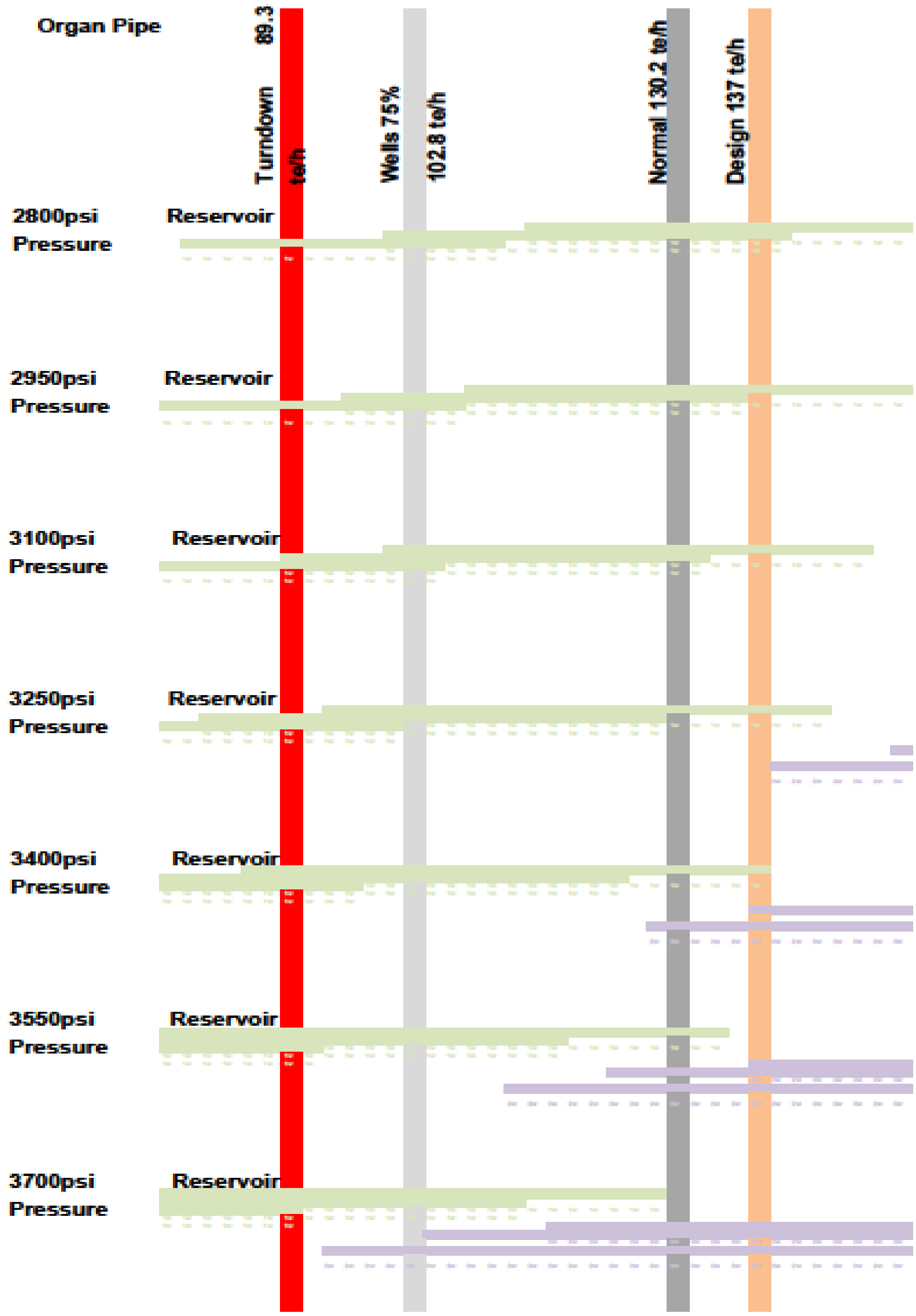


Figure 5-5: Organ Pipe considering three injector wells

Observations to the combination of wells are:

- Initial injection into a single well.
- Later life switching to two injection wells.

The likely injection scenario would be:

- Initial injection into GYA-02S1 for some years.
- Switching to GYA-01 till year 9-10.
- Injection in two wells (likely GYA-02S1 and GYA-04) for years 9-10 to the end of the project.

The wells operating envelopes need to be re-calculated during the detailed design phase and prior to the workover of the wells due to potential difference in reservoir pressures by the start of injection and the well availability.

5.5. Filtration

The recommended filtration requirement is to 5 microns particle size at the wellhead level to avoid erosion of the screens, and erosion and plugging of the screens/gravel pack and formation (1).

There is no allowance for the accumulation of solids inside the screen (lower completion). As such, filtration is a long-term risk mitigation measurement. Filtration will be provided at the Goldeneye platform.

6. Planned Transient Operations

6.1. Well Start-Up Operation – Well Filled With CO_2 at Geothermal Conditions (After a Long Shut-In Period)

Guideline: "*Open the well over 30 minutes to obtain minimum flow in 30 minutes. Use the motorised chokes in multiple stages of proportionally increasing CO_2 rate.*

Increase injection pressure to 50 bara."

This section describes the starting-up of a well when it is filled with CO_2 and the well has been closed for a long time, as such the well is at geothermal conditions (section 4).

When starting up from geothermal conditions the lowest fluid temperatures in the well are reached during a low reservoir pressure start-up. The low temperatures are confined to the top of the well only. At the SSSV depth the fluid temperatures remain relatively high (~22°C).

For the well start-up operations the top of the well will contain gaseous CO_2 phase depending on the reservoir pressure. Rapid 'bean up' of the well is required to avoid cooling due to continuous CO_2 JT effect. This needs to be balanced with the limitation imposed by the lower completion with respect to maximum velocity across the screen / gravel pack. 30 minutes start-up is considered the reference case for normal start-up operations.

6.1.1. Initial Reservoir Pressure (2750 psia) Case Modelling

Modelling was carried out for different start-up operations times. From the geothermal conditions and the well filled with CO_2 at the initial reservoir pressure of 2750 psia [190 bara] (section 3) the flow was ramped to 120 tonnes/h in 5 minutes, 30 minutes and 2 hours. The results of the modelling are shown in Figure 6-1 (start-up operation started at ~0.2 h).

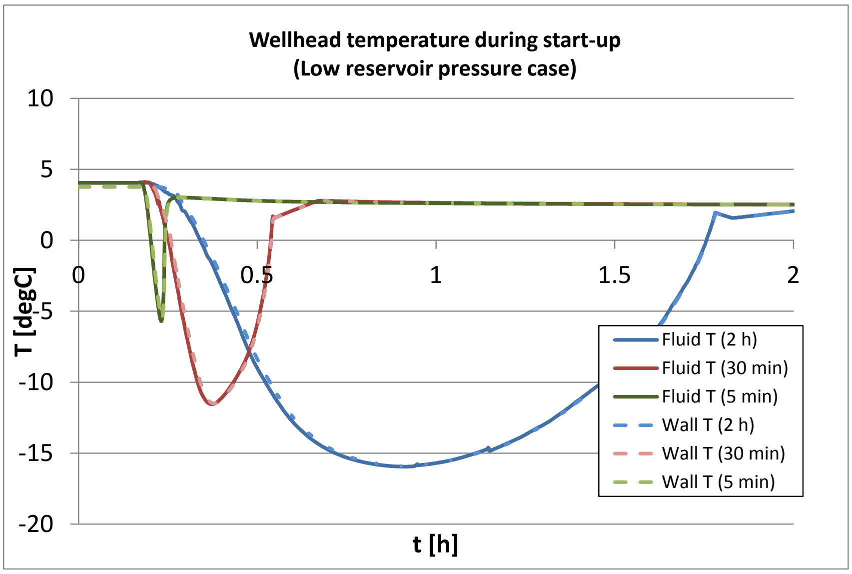


Figure 6-1: CO_2 and tubing wall temperatures during start-up from geothermal conditions (warm well) -190 bara [2750 psia] reservoir pressure

Note that wellhead wall and fluid temperatures are very similar since transients are relatively slow, continuous flow is present and that the heat transfer between the tubing wall and the fluid is very efficient. Ramp-up time has a large effect on wall temperature, with a quick ramp-up of 5 minutes giving the highest minimum temperature (of -6°C) because the tubing head pressure increases as quickly as possible as flow increases due to frictional pressure drop. Ramping up in 30 minutes reduces the minimum wall temperature to -11.5°C, whereas ramping up in 2 hours reduces it further to -16°C. The low temperatures are caused by JT cooling over the wellhead choke, which is dictated by the pressure drop across the choke. This is affected both by the reservoir pressure, which affects CITHP, and by the pipeline pressure. With a faster ramp-up, the period of high choke pressure drop is minimised because the Flowing Tubing Head Pressure (FTHP) increases rapidly as flow increases.

The temperature in different well elements at the wellhead level (top of the well) is described below (Figure 6-2) for the 30 minutes starting-up operation case.

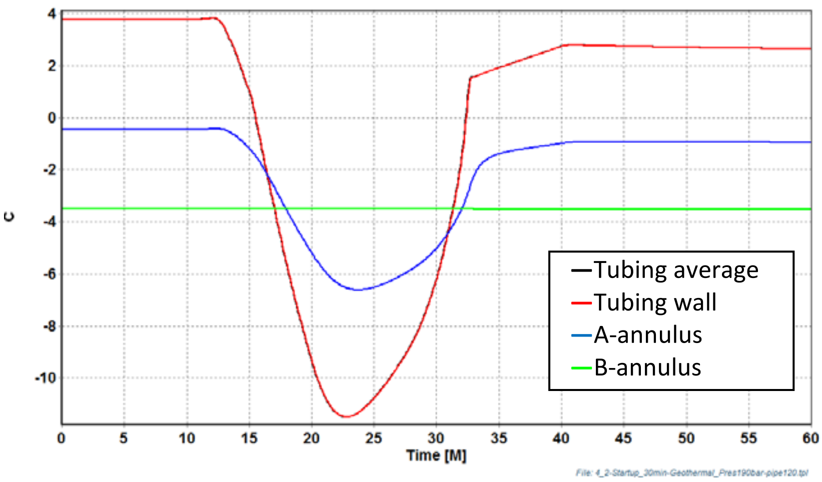


Figure 6-2: Annulus and tubing temperatures at wellhead – top of the well for a 30 minute start-up operation (190 bara [2750 psia] reservoir pressure and geothermal conditions)

Note: In the above figure the Tubing Average and the Tubing Wall are aligned.

The low temperatures are confined to the top of the well only. At the SSSV fluid temperatures remain high, Figure 6-3. The large amount of JT cooling in the gaseous phase means that starting up at lower CITHP will cause a significant amount of additional cooling. During the 30 minutes start-up from 190 bara reservoir pressure the Tubing Head Pressure (THP) reaches a minimum of 25 bara, from its initial value of 39 bara.

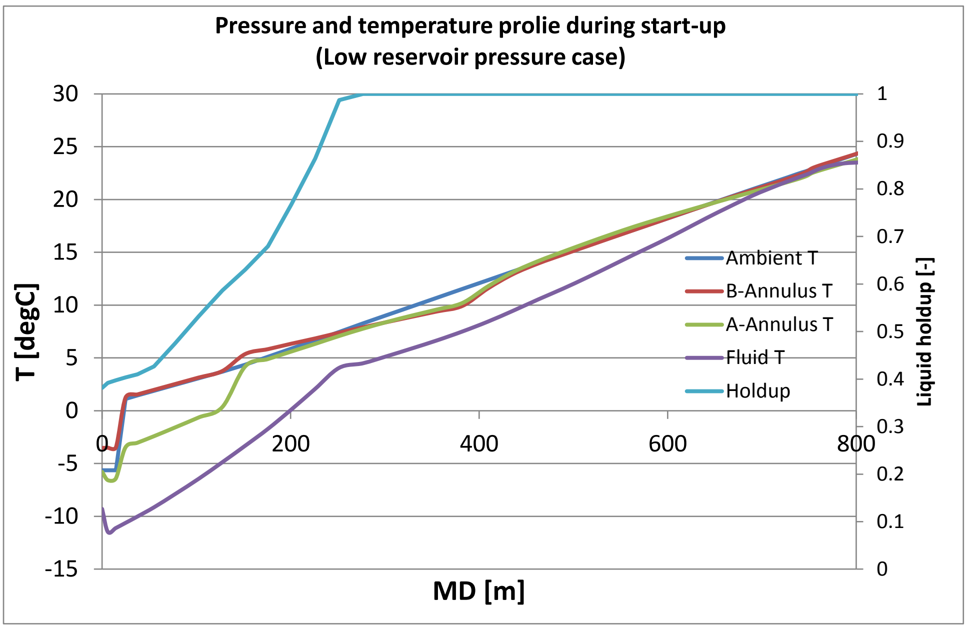


Figure 6-3: Temperatures at the minimum wellhead fluid temperature (23 minutes) in a 30 minute start-up operation (190 bara [2750 psia] reservoir pressure and geothermal conditions)

6.1.2. Final Reservoir Pressure (3830 psia) Modelling

When injection is started from geothermal conditions at high reservoir pressure, no gaseous CO_2 is present near the wellhead. The initial fluid temperature in the well at the wellhead is below -5°C (as a result of the ambient air temperature of -5.8°C). Note that injection leads to rapid warming at the wellhead since the incoming CO_2 is around 4 °C, Figure 6-4.

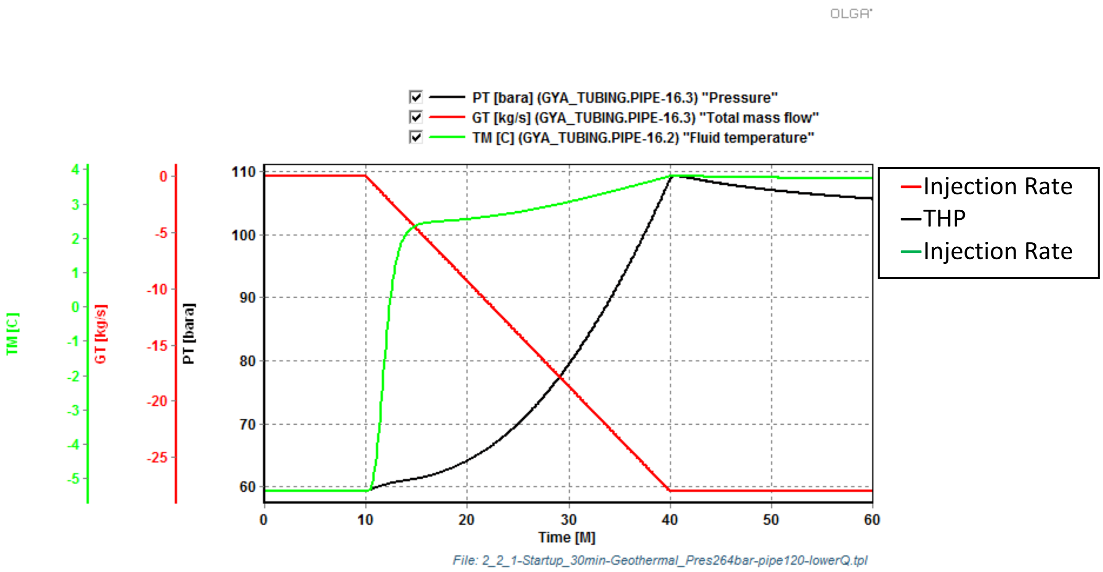


Figure 6-4: Wellhead conditions during 30 minutes start-up from geothermal conditions (warm well) – 264 bara [3830 psia] reservoir pressure.

6.2. Close-in Operation after a Long Period of Injection

Guideline *"Bean back the well. Reduce injection pressure to 50 bara.*
Close the well or bring the flow to zero in stages – 30 minutes."

This scenario is for a well that needs to be closed after a long period of injection, section 4; the well is under cold conditions with bottomhole temperatures in the order of 20-25°C.

During close-in operations the frictional pressure drop over the well is reduced, resulting in a lower injection tubing head pressure. This results in JT cooling as long as CO_2 is still supplied by the pipeline. At the end of the close- in operation the CO_2 in the top of the tubing will be in form of gaseous state due to the depleted reservoir condition. The gas-liquid interface will be shallower with increasing reservoir pressure. The lower the reservoir pressure, the more cooling is expected in the well.

During normal well operations the wells need to be closed-in in 30 minutes. This is a balance between closing the well rapidly to avoid cooling of different well elements and 'hammer' effects induced by closing the wells too rapidly.

The recommended guideline is to:

- 'Bean back' the well.
  Reduce injection pressure to 50 bara. This operation can be done using the motorised choke installed on each well.
- Close the well or bring the flow to zero – over a 30 minute period.
  It was modelled as a continuous ramp-down of flow to zero in 30 minutes.

Alternatively, close the well in 30 minutes by reducing the injection rate in 5 proportional stages of approximately 6 minutes each.
Motorised choke will facilitate this operation.

There is no requirement to inject methanol during this operation as CO_2 at the specification level is still injected into the well and there is no water in the well, section 7.2.2.

The minimum temperature observed in the different well elements are described Table 6-1:

Table 6-1: Minimum temperatures during shut-in (30 minute ramp-down after a long period of injection)

Parameter	Value	Value	Remarks
Reservoir Pressure, psia	2750	3830	Initial and final reservoir pressures for this report.
Minimum Fluid Temperature, °C	-21	-4	At the wellhead level
Minimum Wall Temperature, °C	-21	-3	At the wellhead level
A-annulus temperature, °C	-11	-3	At the wellhead level
Production casing, °C	-4	-3	At the wellhead level
B-annulus temperature, °C	-4	-3	At the wellhead level
Surface casing, °C	-4	-4	At the wellhead level
CO_2 temperature at SSSV depth, °C	2	7	

6.2.1. Initial Reservoir Pressure (2750 psia) Case Modelling

Modelling was carried out for different closed-in times at reservoir pressure of 2750 psia. The shut-in time was simulated by ramping down the injection rate from 120 te/h to zero in 5 seconds (emergency shutdown), 30 minutes and 2 hours, Figure 6-5.

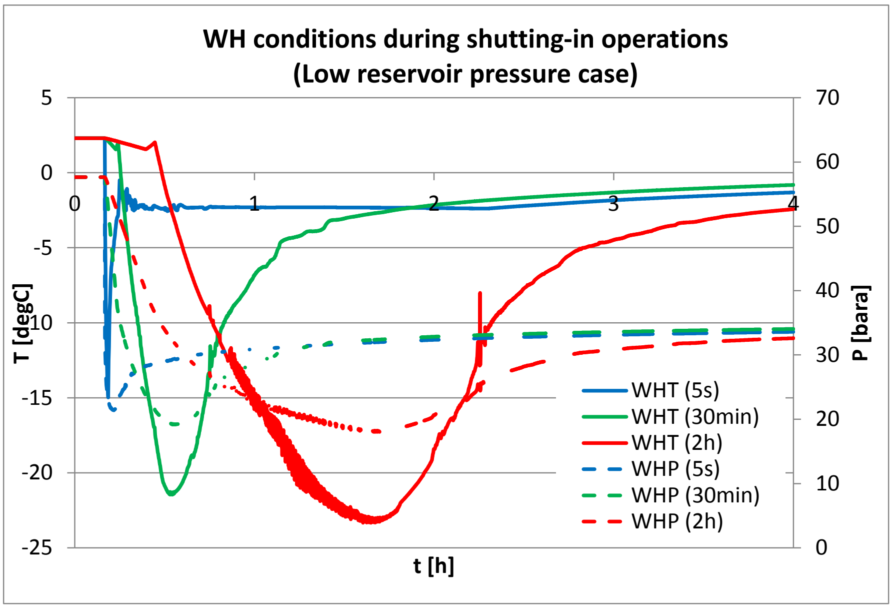


Figure 6-5: Wellhead CO_2 conditions for closing-in operation after a long period of injection – 190 bara [2750 psia] reservoir pressure

THP drops causing high JT cooling over the choke. Note that for the 30 minutes and 2 hours flow ramp-down wellhead temperatures drop below -18°C, the temperature limit of the wellhead. For a ramp-down in 30 minutes, fluid temperature drops below -18°C for only 15 minutes. CFD (Computational Fluid Dynamics) simulations have shown this is acceptable over the given period of time (section 7.2), as the wellhead is not in direct contact with the CO_2. The temperature of the CO_2 at the SSSV during this operation will be above 2°C.

6.2.2. Final Reservoir Pressure (3830 psia) Modelling

The same calculations for closing the well were performed for the high reservoir pressure in ramping down at different time periods, Figure 6-6.

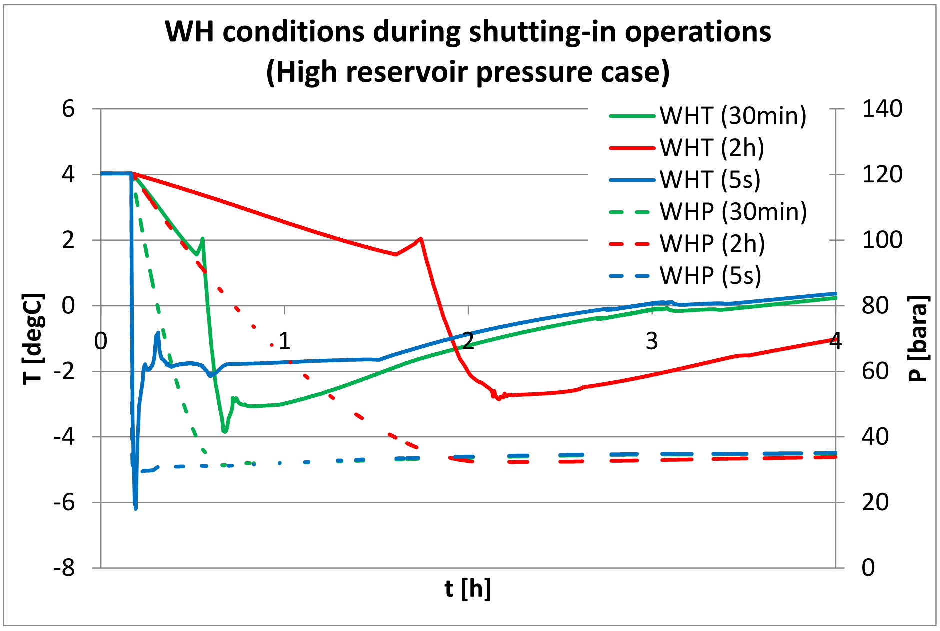


Figure 6-6: Wellhead CO_2 conditions for closing-in operation after a long period of injection – 264 bara [3830 psia] reservoir pressure

The CO_2 conditions at the wellhead are not as cold as the low reservoir pressure case due to a higher back pressure (wellhead pressure) induced by the reservoir.

6.3. Minimum Shut-in Time Before Starting-up the Well

Recommendation: A minimum of 30 minutes shut-in time after closing-in the well is required before attempting to re-start injection.

The overall temperature in the well will increase with time during the shut-in period after a close-in after a long injection period. This is illustrated in Figure 6-7 where the tubing head conditions of the CO_2 are presented.

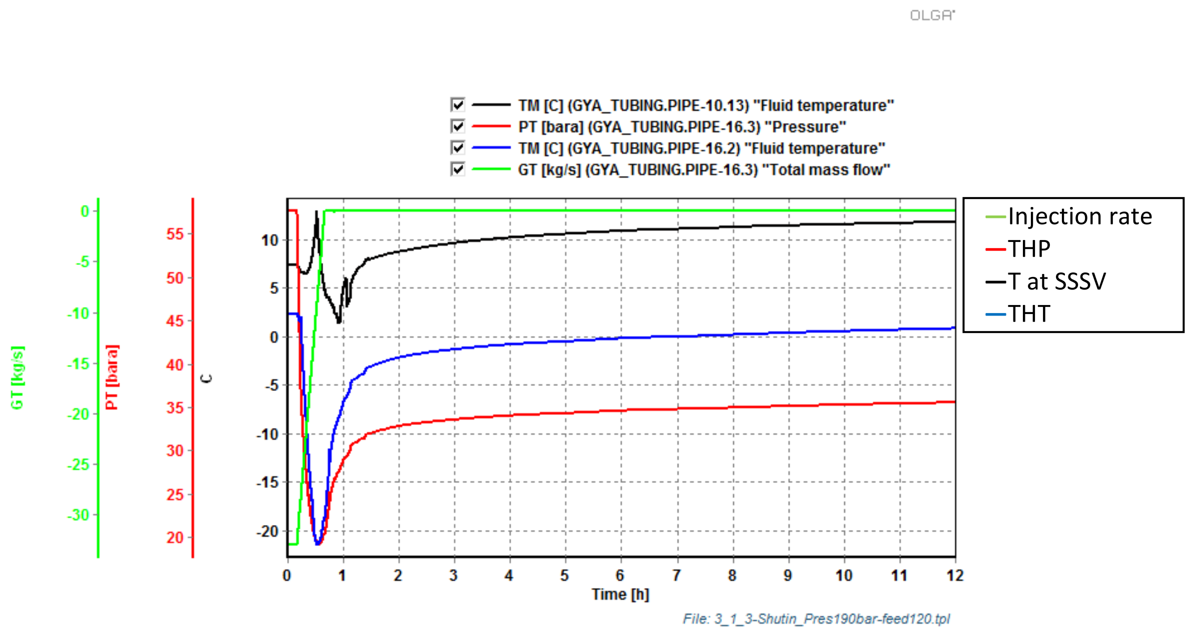


Figure 6-7: Well conditions when the well is closed-in after 30 minutes shutting-in operation.

During the shut-in period the well will slowly approach geothermal conditions, Figure 6-8. It is also observed that the CO_2 gas-liquid interface level changes with time as the CO_2 density changes as the well warms up.

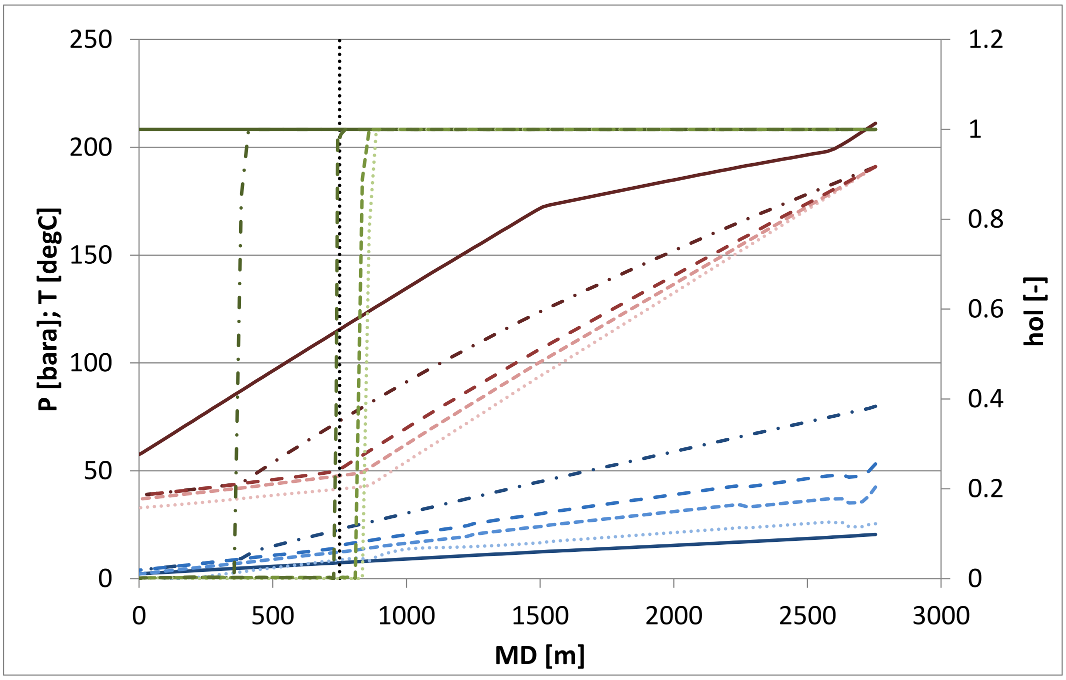


Figure 6-8: Well conditions following a shut-in at low reservoir pressure – 190 bara [2750 psia]. Conditions shown: flowing (solid), 2 hours after shut-in (...), 1 day after shut-in (---), 1 week after shut-in (- -) and geothermal (- .)

The shut-in period will have an impact in the well start-up operations. If the well is left shut-in for a long period of time then the starting-up operation will be similar as starting from geothermal conditions (section 6.1) or if the well is closed-in for a short time then the well is starting up from relatively cold conditions (section 6.4).

In section 7.2.2 it is indicated that there is not a problem arising from two-phase injection if the injection time under these conditions is limited to a maximum of 2 hours. As such, considering the recommended guideline for the close-in operation of 30 minutes and the recommended guideline of starting-up the well in 30 minutes it is possible (in theory) to open the well immediately after the close-in operation.

However, it is considered prudent to wait for at least 30 minutes prior to starting-up the well. This will allow the top of the well to warm-up before attempting to start-up the injection with a new cycle of cold conditions in the top of the well.

6.4. Well Start-up Operation (After a Short Shut-in Period)

Guideline *Open the well over 30 minutes to obtain minimum flow in 30 minutes (injection pressure of 50 bara depending on the operating envelope of the well, section 5.3)*

Used the motorized chokes in multiple stages of proportionally increasing CO_2 rate to obtain the minimum rate in 30 minutes.

The CO_2 conditions during start-up after short shut-in period will be influenced by the series of events before the start-up operation.

During start of injection there will be a pressure drop seen at the tubing head due to differences in CO_2 density. Later, the pressure will increase, as frictional pressure drop comes into play.

For the well start-up operations the top of the well will contain gaseous CO_2 phase. Rapid 'bean up' of the well is required to avoid cooling due to the CO_2 JT effect. This needs to be balanced with the limitation imposed by the lower completion with respect to maximum velocity across the screen / gravel pack (1).

The sequence of steady state injection, close-in operation (30 minutes), shut-in time (30 minutes) and start-up operation (30 minutes) was simulated for low reservoir pressure of 2750 psia, Figure 6-9 and Figure 6-10. The minimum CO_2 temperature at the SSSV depth is above 0°C. From the figures, it can be observed that there are no significant differences with the simulation during the close-in operation, Figure 6-5. The temperature in the B-annulus is not affected by the recommended process of closing and opening the well.

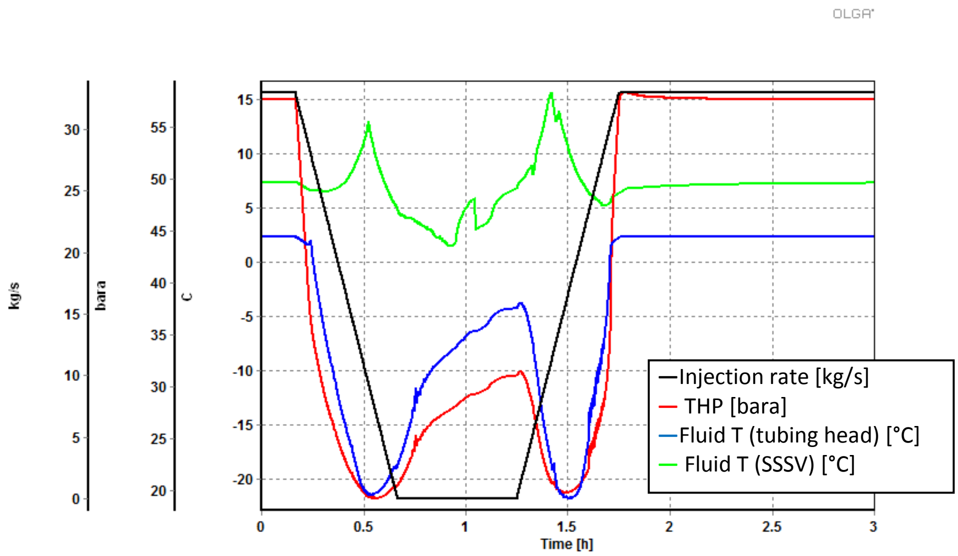


Figure 6-9: Tubing head conditions and SSSV temperature during 30 minutes starting-up operation after 30 minute shut-in at 190 bara [2750 psia] reservoir pressure

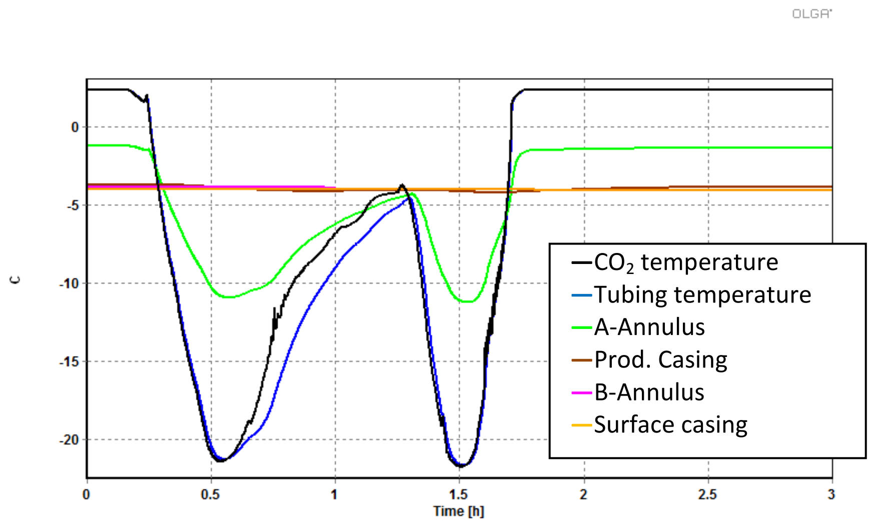


Figure 6-10: Tubing, annuli and casing temperatures during 30 minutes starting-up operation after 30 minute shut-in at 190 bara [2750 psia] reservoir pressure

6.5. SSSV Testing

Guideline: *"During SSSV testing it is crucial to control tubing head pressure during both the bleed down phase and the testing phases.*

The well behaviour can vary significantly depending on the conditions in the well prior to testing".

The following procedure avoids extreme low temperatures under all conditions:

Table 6-2: SSSV Testing Procedure

Step	Duration [hours]
Close-in well (standard procedure)	0.5
Wait for interface to stabilise (shut-in period)	0.5
Close SSSV	-
Bleed-off THP, keeping pressure at 24 bara. Boiling Off time depends on well conditions CO_2 boiling process should be monitored using DTS Automatic pressure control valve (PCV) to be installed in the platform to control the tubing head pressure. If DTS not available then bleed-off time of 12 hours	0 – 10
Shut tree valve once boiling complete	-
Monitor THP • Increase < 0.1 bara/h: no leak • Increase > 0.3 bara/h: possible leak exceeding API criteria (only if gaseous flow is present – low reservoir pressure and after injecting for a long period of time) o Increase >1.5 bara/h: leaks exceeds API criteria. This criterion can be used if liquid CO_2 is passing through the SSSV (by far most common scenario)	2

After closing the SSSV, verification of closure may be accomplished by a pressure in-flow test. The SSSV can be tested for leakage by opening the surface valves to check for flow. The SSSV is reopened following the procedures in the manufacturer's operating manual.

SSSV has an allowable leak rate advised in API recommended practice API RP 14B (ISO 10417) of 400 cm^3/min of liquid or 0.43 m^3/min [15 scfm] of test gas. In case of higher values corrective action should be taken to meet the requirements of this international standard.

The test is divided in 3 stages:

- Bleed-off operation. Wait for all the CO_2 to boil-off.
- Pressure monitoring.
- Re-start injection.

6.5.1. Bleed-off Operation

Although specific procedures may vary, the standard procedure for hydrocarbon wells consists of shutting in a well at the wellhead, closing the SSSV and bleeding off the CITHP to a value lower than its initial value (typically down to 10%).

In CO_2 wells the above approach can lead to low temperatures, as any liquid CO_2 present above the SSSV when it is shut in will boil off with time. For example, a CITHP of 60 bara would require a final bleed-off pressure of 6 bara. Temperatures in the order of -53.1 °C can be encountered in rapid depressurisation according to the saturation/boiling curve of the CO_2. In summary, the temperature at the SSSV during the boil-off process is very sensitive to the tubing head pressure.

This was simulated in OLGA for the worst case, bleed-off to atmospheric conditions, where temperatures of around -77°C were calculated at the valve for approximately 30 minutes for the low and high reservoir pressures scenarios with metal temperatures close to the triple point of the CO_2 (~55°C).

The current SSSV lowest temperature limit is -7 °C which has been used to evaluate the minimum allowable temperature at the SSSV during the test. From this temperature the minimum bleed-off pressure is calculated to be 24 bara. Sensitivities were also performed using OLGA to optimise this value.

6.5.1.1. Reference Case - Maintain Back Pressure

The length of the boiling process (or bleed-off time) will depend on the initial condition before the test for the same bleed-off pressure. In general, the boiling process depends on the location of the gas liquid CO_2 interface after the SSSV has been closed (just prior to bleeding). There might be different liquid-gas CO_2 levels before the test depending on the reservoir pressure and if the well is cold after the injection or if the well is at geothermal conditions.

Table 6-3: Bleed-off time and minimum temperature for different reservoir pressures and conditions

Case	Back Pressure, bara	Boiling off time, hours	Minimum Fluid T @ SSSV level, °C	Minimum Fluid T @ tubing head level, °C
Cold well **High reservoir pressure (3830 psia)**	24	9.5	-7	-14
Geothermal well **High reservoir pressure (3830 psia)**	24	2.5	-7	-13
Cold well **Low reservoir pressure (2750 psia)**	24	0	2	-2
Geothermal well **High reservoir pressure (2750 psia)**	24	2	-7	-14

SSSV leak testing (inflow testing) should only be initiated once boiling is complete. To ensure the temperature at the SSSV remains above -7 °C (current limitation of the valve) over the full range of cases, pressure should not be bled off lower than 24 bara.

It is difficult to predict exactly gas liquid CO_2 interface positions and boil-off period for all well life cycle conditions. It is therefore recommended to track the boiling process and interface position during bleed-off, which can be done using DTS (Distributed Temperature Sensors) measurements in the A-annulus. The CO_2 temperature will increase when the CO_2 has boiled off and this will have an effect on the A-annulus temperature, Figure 6-11. It is therefore important to be able to monitor the A-annulus temperature just (1-2 m) below and above the SSSV.

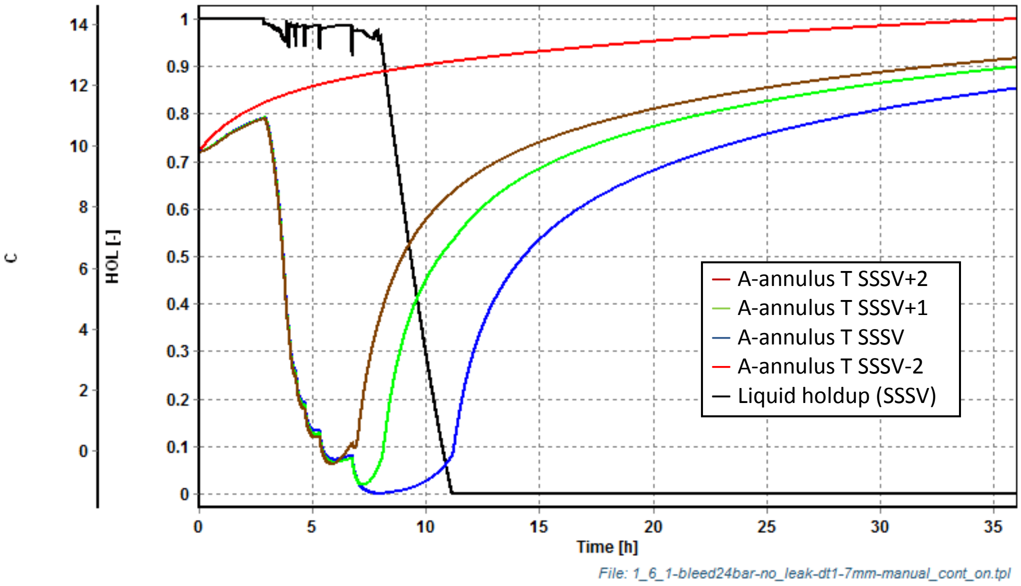
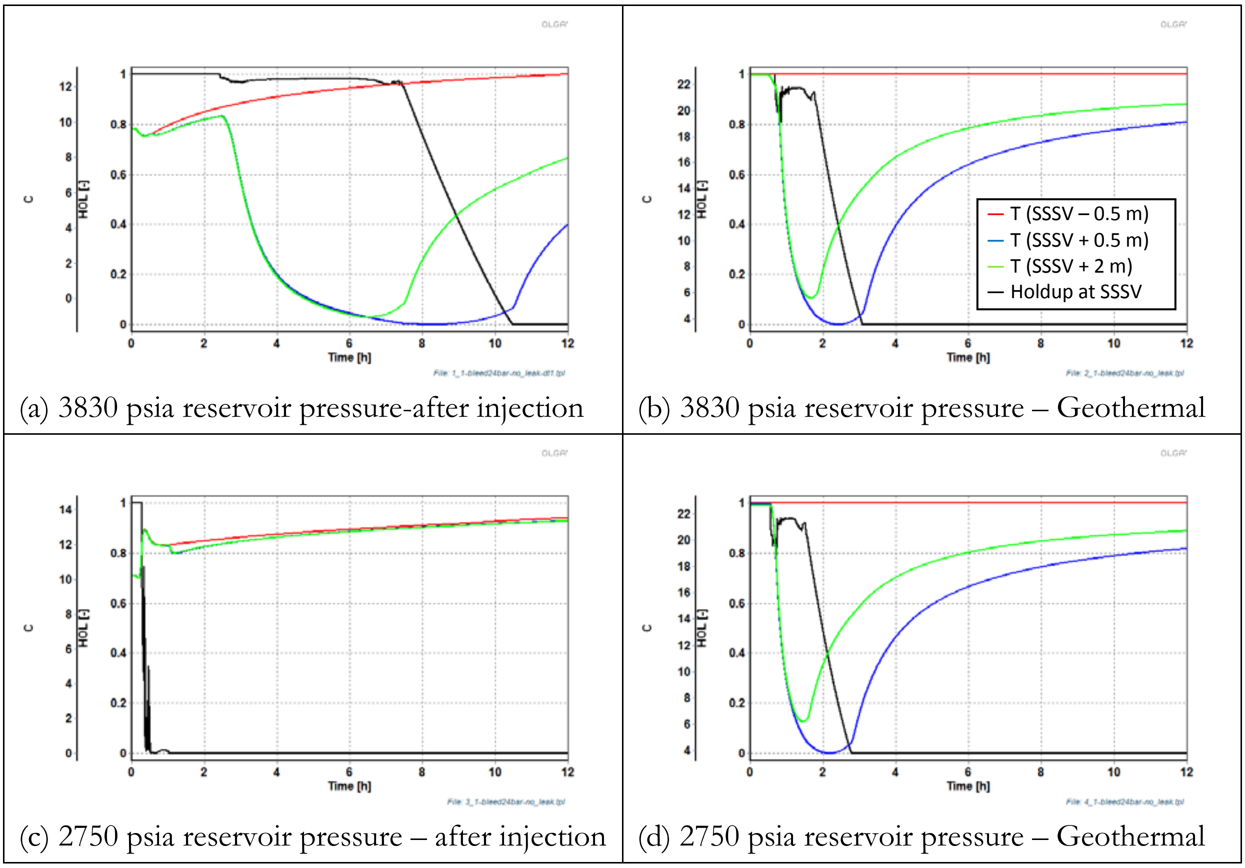


Figure 6-11: A-annulus temperature reading around the SSSV during boil-off time of the CO_2. Distribute Temperature Sensors (DTS) will be able to pick the temperature.

In order to be able to accurately detect leaks (section 6.5.2), it is crucial to continue the bleed process until all CO_2 above the SSSV has boiled off. Starting the test too early will lead to an incorrectly interpreted leak.

For high reservoir pressure and a well under cold conditions after injection, boiling-off time is long at around 10 hours, Table 5-3. As mentioned before the DTS would be able to pick the difference in temperature around the SSSV in the A-annulus during the boiling-off process.



(a) 3830 psia reservoir pressure-after injection
(b) 3830 psia reservoir pressure – Geothermal
(c) 2750 psia reservoir pressure – after injection
(d) 2750 psia reservoir pressure – Geothermal

Figure 6-12: Detectability of CO_2 boiling above the SSSV in the A-annulus for different cases

If DTS measurements are not available, it is advised to wait for 12 hours (the longest simulated boil-off period).

6.5.1.2. Alternatives of Bleed-off Pressure (Not Followed By the Project)

Simulations were carried out to evaluate if installing a small orifice (4 mm) instead of the control to 24 bara would increase the temperature of the CO_2 by reducing the boil-off rate where the heat from the formation would be dominating factor. However, the simulation showed that a temperature of -44°C would be encountered at the SSSV.

Simulations were also performed to evaluate the use of a larger small orifice (7 mm) with an operator controlling the bleed-off pressure, Figure 6-13. In this case, control was assumed to consist of an operator closing the orifice when THP reaches 23 bara, and opening it again when the pressure reaches 25 bara. Around 8 interventions are required during the bleed-off process, which takes around 11 hours. It can be done but it will be subject to multiple interventions for long periods of time where mistakes can occur. As such, it is recommended to perform the bleed-off process with a pressure control valve (Figure 6-14 and section 6.5.1.1) instead of a manual operation.

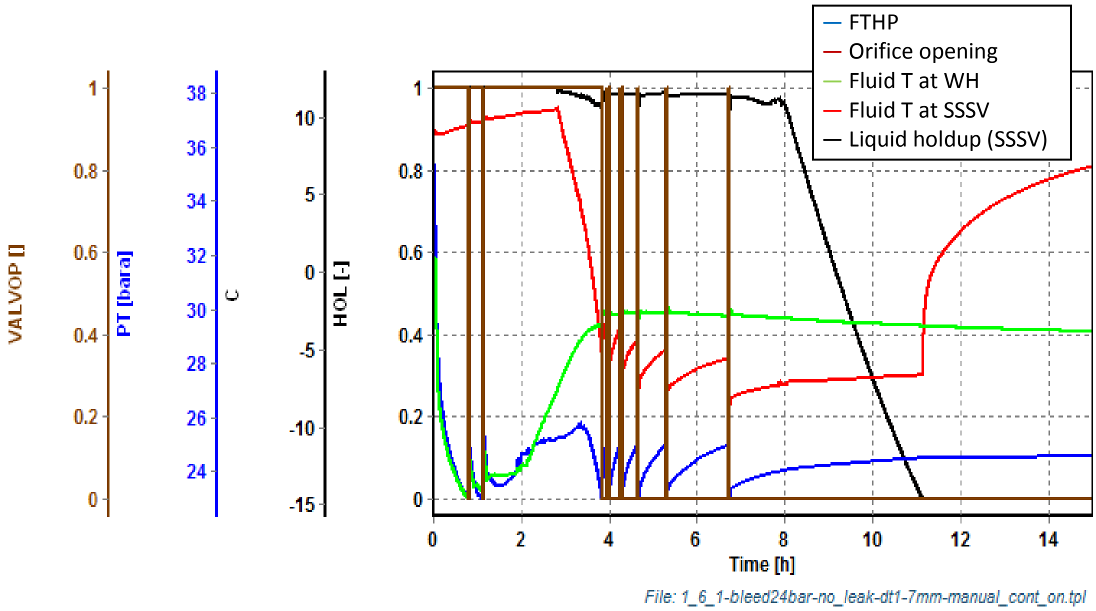


Figure 6-13: Bleed-off after long injection (cold well) at 264 bara [3830 psia] reservoir pressure - 7 mm orifice manual control

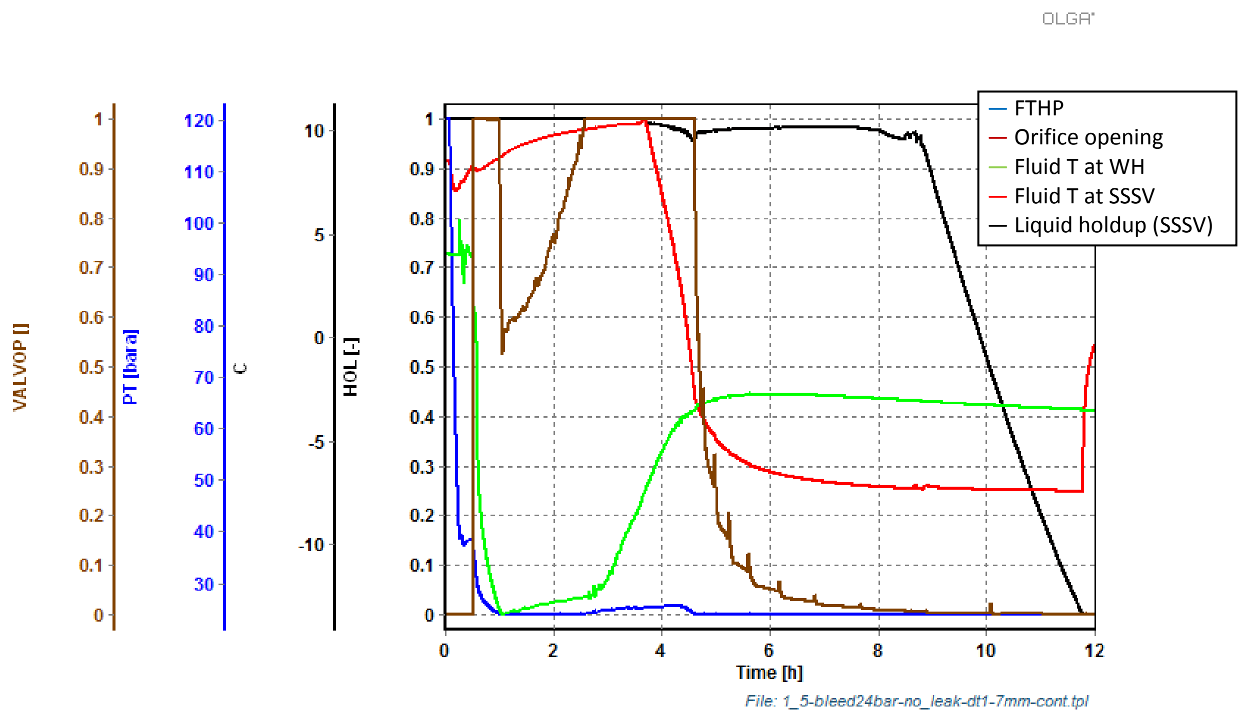


Figure 6-14: Bleed-off after long injection (cold well) at 264 bara [3830 psia] reservoir pressure - 7 mm orifice automated control

6.5.2. Leak Detection at 24 bara Bleed-off Pressure

API regulations prescribe a maximum allowable leak rate across SSSVs in oil and gas wells. When translated to CO_2, the maximum leak rate is 0.006 – 0.013 kg/s. A 0.3 mm leak at the SSSV gives a leak rate of 0.01 kg/s.

Once the CO_2 has boiled-off to 24 bara tubing head pressure the bleed valve needs to be closed. After the bleed valve is closed, THP can be tracked to detect SSSV leaks, as a leak at the SSSV will cause the THP to increase. The THP also increases due to heating of the CO_2 vapour column between the SSSV and the wellhead.

This process was simulated using OLGA for a high reservoir pressure after injection conditions; Figure 6-15 shows the bleed-off phase for a SSSV with and without a leak for an initial condition of a well after injection and high reservoir pressure. The wellhead choke is closed in 15 minutes, starting at 5 minutes. At the CITHP of around 38 bara, some CO_2 boils off at the wellhead. After 20 minutes the choke is fully closed and the SSSV is closed. At 30 minutes the bleed valve is opened. A pressure Proportional-Integral-Derivative (PID) controller is used to prevent THP dropping below 24 bara, Figure 6-15.

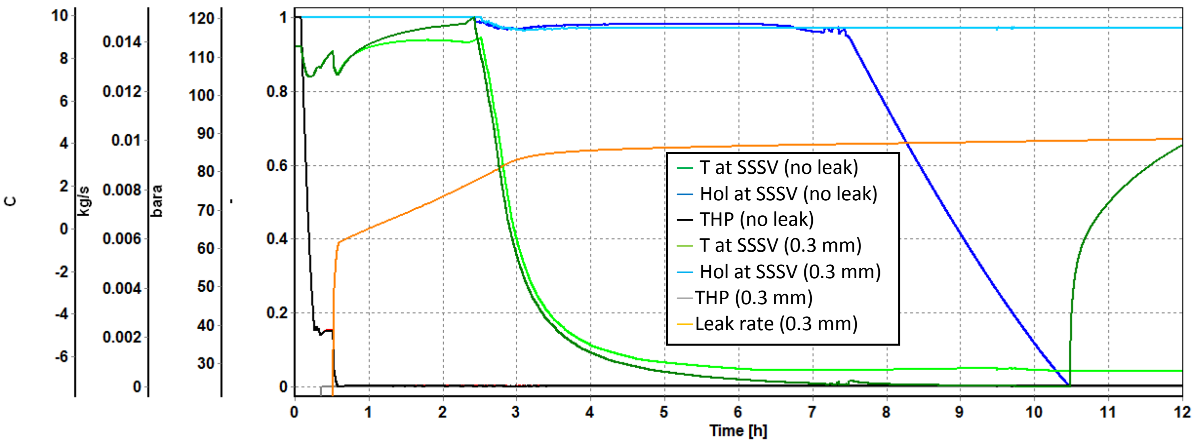


Figure 6-15: Bleed-off phase prior to SSSV testing considering a fully sealing valve and a 0.3mm leaking valve – 264 bara [3830 psia] reservoir pressure and cold conditions after injection

Note that the 0.3 mm leak results in a leak rate of around 0.01 kg/s. At around 2.5 hours the temperature at the SSSV drops. At this stage the conditions at the SSSV are such that CO_2 starts boiling. Holdup is somewhat below 1 as part of the CO_2 boils off. Due to the THP control, temperature does not drop below -7°C. However, the boiling off process is slow; after 7.5 hours the holdup in the cell just above the SSSV starts to reduce when the SSSV is sealing. After 10.5 hours all CO_2 above the SSSV has boiled off, and SSSV temperatures start to increase. In case of a leak across the SSSV, this does not happen as a continuous supply of dense phase CO_2 exists. This CO_2 flashes across the valve, resulting in low temperatures.

With a leaking SSSV, CO_2 never completely boils off. Note from Figure 6-16 that initially temperature at the SSSV is around -7°C for a leaking SSSV due to continuous boiling. The sealing SSSV has also been heated up somewhat by the formation. Upon closing the bleed valve shortly after 12 hours THP immediately starts to increase by around 1.5 bar/h for the leaking SSSV. This should be detectable in a test lasting 1-2 hours. For the sealing SSSV this pressure increase is only around 0.03 bar/h. This increase is due to the formation heating the CO_2 vapour above the SSSV.

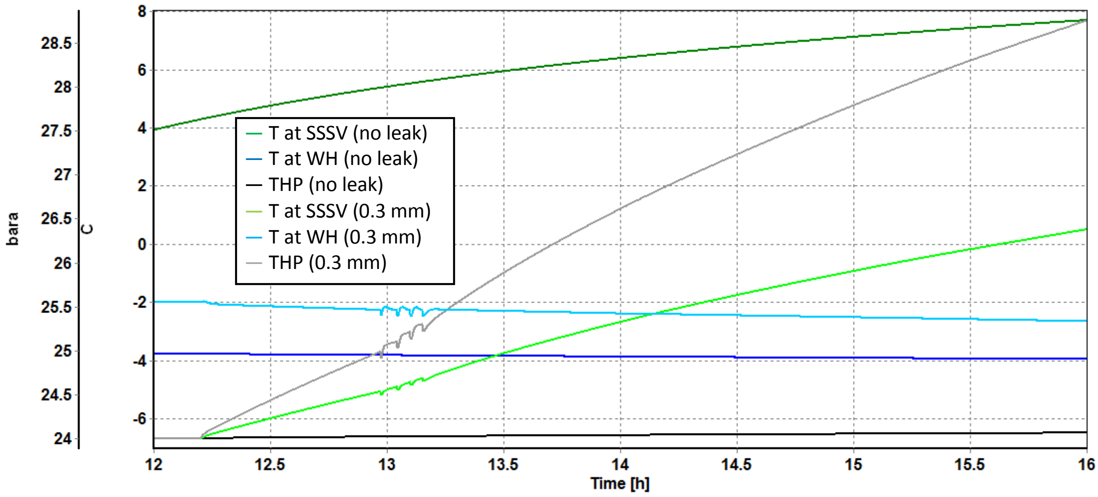


Figure 6-16: SSSV leak detection at 264 bara [3830 psia] reservoir pressure and cold conditions after injection

Table 5-4 gives an overview of all results. For a non-leaking SSSV THP increases by less than 0.1 bara/h for all well conditions. Even a small leak – equating to the maximum allowable API leak rate – results in a pressure increase of around 1.5 bara/h, which is detectable. Different well conditions were simulated with the following results, Table 5-4.

Table 6-4: Summary of well detectability for different well conditions and leak size at the SSSV

Case	Leak Size, mm	Boil- off time, hours	Leak rate, kg/s	dP/dt, bara/h	Min SSSV T during bleed, °C	Min SSSV T during test, °C
3830 psia reservoir pressure, after injection	0	9.5	0	0.03	-7	4
3830 psia reservoir pressure, after injection	0.3	∞	0.01 (L)	1.4	-7	-7
3830 psia reservoir pressure, geothermal	0	2.5	0	0.1	-7	14
3830 psia reservoir pressure, geothermal	0.3	∞	0.01 (L)	1.5	-7	-7
2750 psia reservoir pressure, after injection	0	0	0	0.06	2	12
2750 psia reservoir pressure, after injection	0.3	0	1.5E-3 (G)	0.3	8	6
2750 psia reservoir pressure, geothermal	0	2.5	0	0.06	-7	15
2750 psia reservoir pressure, geothermal	0.3	∞	8 E-3 (L)	1.4	-7	-7

The low reservoir pressure (2750 psia) after injection (cold well) case shows a different behaviour. Because the well is cold initially the density of the column of liquid CO_2 is relatively high. Combined with the low reservoir pressure this causes the CO_2 interface to move below the SSSV.

Around 1 hour is required for the interface to stabilise before the SSSV is closed. The interface level needs to be checked using DTS to check whether it is stable. As the tubing above the SSSV is full of gas the bleed-off period is relatively quick (boil-off not required).

Once the 24 bara pressure is obtained the bleed valve can now be closed and THP tracked. Although not shown in this graph Figure 6-17, the leak rate through the 0.3 mm leak is now only 0.0015 kg/s, around 1/6th of the 0.01 kg/s observed in other scenarios, Table 5-4. The reason for this is the fact that in the scenario of low reservoir pressure and after injection, gaseous CO_2 is flowing through the leak, whereas in all other cases the interface has stabilised above the SSSV and liquid CO_2 is flowing through the leak. With the SSSV closed, a leak test can be done as before.

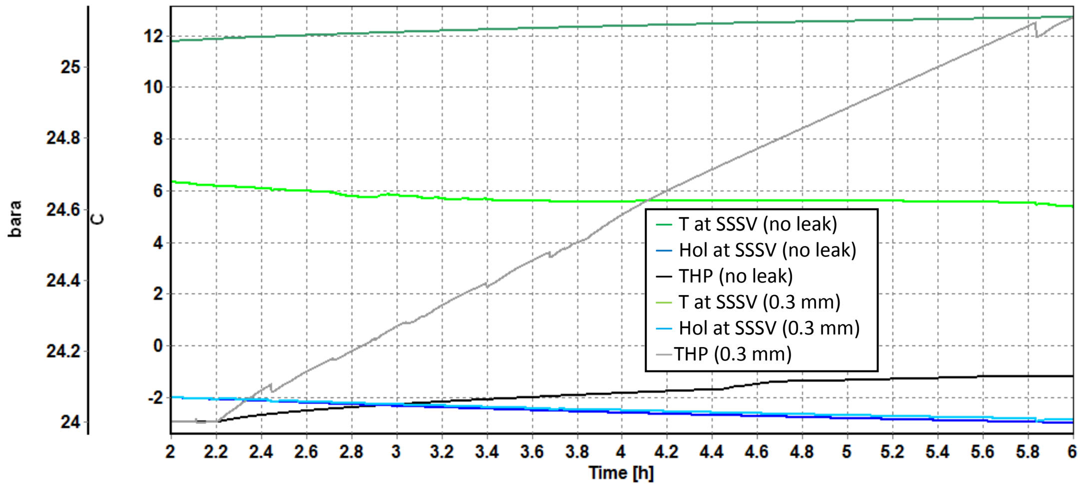


Figure 6-17: Low reservoir pressure (2750 psia) – and after injection conditions (cold well) - SSSV leak detection at 190 bara reservoir pressure

Note that the increase in THP with the same 0.3 mm leak is now much smaller than before, with THP only increasing at around 0.3 bara/h, compared to 1.5 bara/h previously. Since leak rate is only 1/6th of the other cases, the pressure increase is also 1/6th. With a sealing SSSV, the observed THP increase is 0.06 bara/h, which is still significantly lower. However, the test must be done carefully to be able to detect a leak at cold, low pressure initial conditions.

Summary

In general, a pressure increase of more than 1.5 bara/h indicates a valve leaking at a higher rate than allowed. A leak of vapour-phase CO_2 through a leak of the same size, which occurs in case of low reservoir pressure after long time of injection, is more difficult to detect.

If the SSSV test indicates a leak, this may be due to the fact that CO_2 is still boiling off. In that case, the bleed period needs to be extended by several hours before repeating the test.

6.5.3. Re-Starting operation following SSSV test

The THP will be around 24 bara after the test and the SSSV is closed. This is lower than the CITHP during normal closed-in condition, and hence upon CO_2 injection higher JT cooling is expected in the top of the well.

The valve is holding pressure from below which depends on the reservoir pressure assumed.

To open the valve, pressure from below and above the valve need to be equal (pressure equalisation). This will have an impact in the minimum temperatures to be observed above the SSSV.

The procedure to open the valve was modelled in OLGA using a check valve to take into account that the SSSV is opened by fluid pressure from the surface. The wellhead choke was opened in 30 minutes in the simulation, Figure 6-18 and Figure 6-19. Tubing head temperature reaches a minimum of -18°C for low reservoir pressures and -14°C for higher reservoir pressures, which are within the limits of the different well elements. Note that the temperature at the SSSV for both cases is above 5°C.

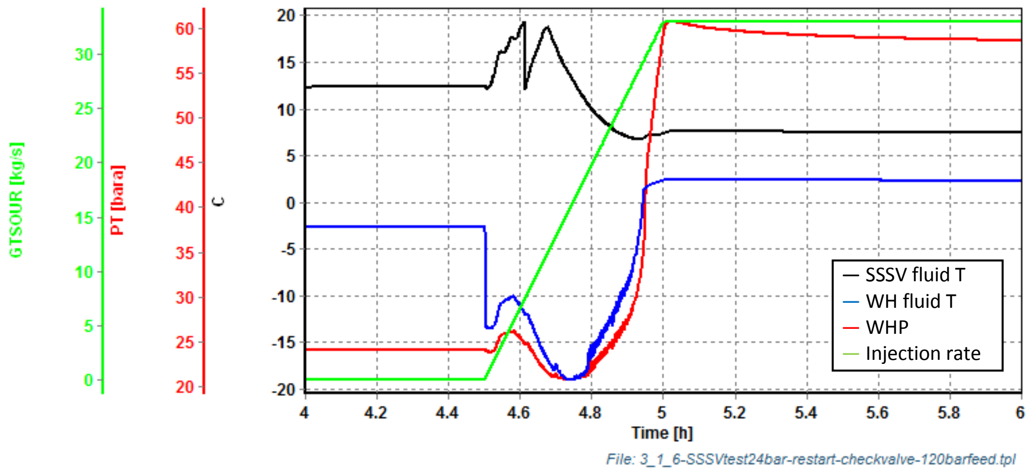


Figure 6-18: Injection re-start after the SSSV test. Low reservoir pressure (2750 psia) and well after injection

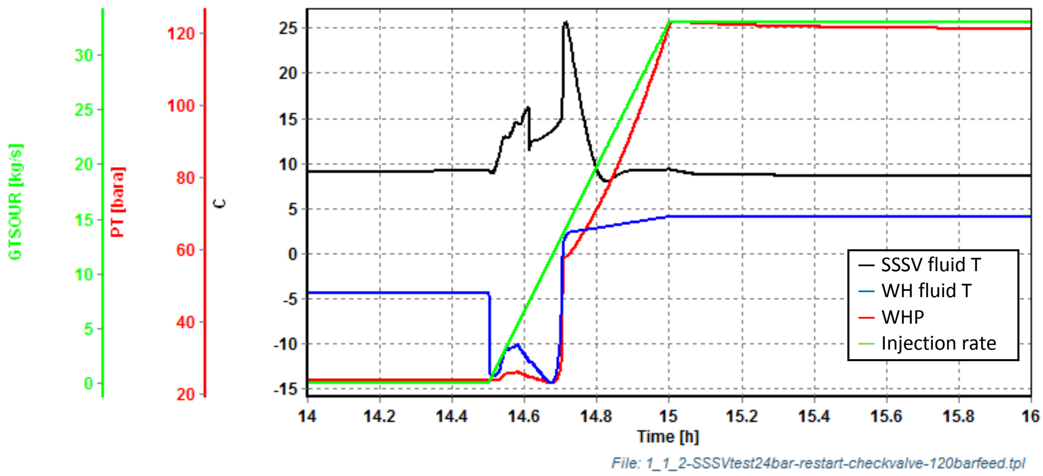


Figure 6-19: Injection re-start after the SSSV test. High reservoir pressure (3830 psia) and well after injection

This guideline is not ideal as the pressure equalisation across the valve is not followed by the pressurisation of the control line. This might lead to damage to the SSSV seal face over a prolonged period of injection. It is better to equalise the valve using methanol (section 8.3.6) and then to re-commence injection. This procedure can be used as a back-up and indicates the worst case condition in terms of JT cooling.

6.6. Initial Well Start-up (Introduce CO_2 in the Well)

Guideline: *Use a 30 bara N_2 cushion at the top of the well for the initial injection of the well.*

Methanol batch injection is required to avoid hydrate deposition in the initial injection. A methanol column of 2500 ft TVD is required – 6.0 m³ in the 4 ½" tubing.

The length of the required N_2 cushion depends on the reservoir pressure at the start of the injection and the density of the fluid left below the N_2 cushion.

For 2800 psia reservoir pressure and seawater left in the tubing, then the N_2 cushion length is calculated at 2770 ft TVD.

CO_2 has not been introduced to the well for this scenario. This is the very first time CO_2 will be introduced in the well.

The fluid left in the tubing should be compatible with the well components and with the reservoir/formation. From the injectivity perspective, it is better to have a water-based fluid, rather than base oil or diesel to avoid the introduction of a new fluid in the wellbore, which might affect the relative permeability to CO_2.

In addition, the completion fluid should minimise the JT effects of the CO_2 expansion in the top of the well. The JT effect will be significant in the case of low tubing head pressures. A minimum tubing head pressure of 30 bara is required to minimise the JT expansion (saturation temperature of -5.5 °C).

The initial reservoir pressure before injection is estimated at 2800 psia for a gradient of 0.333 psia/ft which is lower than the average seawater gradient 0.45 psia/ft. The top of the well will be at atmospheric pressure, Figure 6-20.

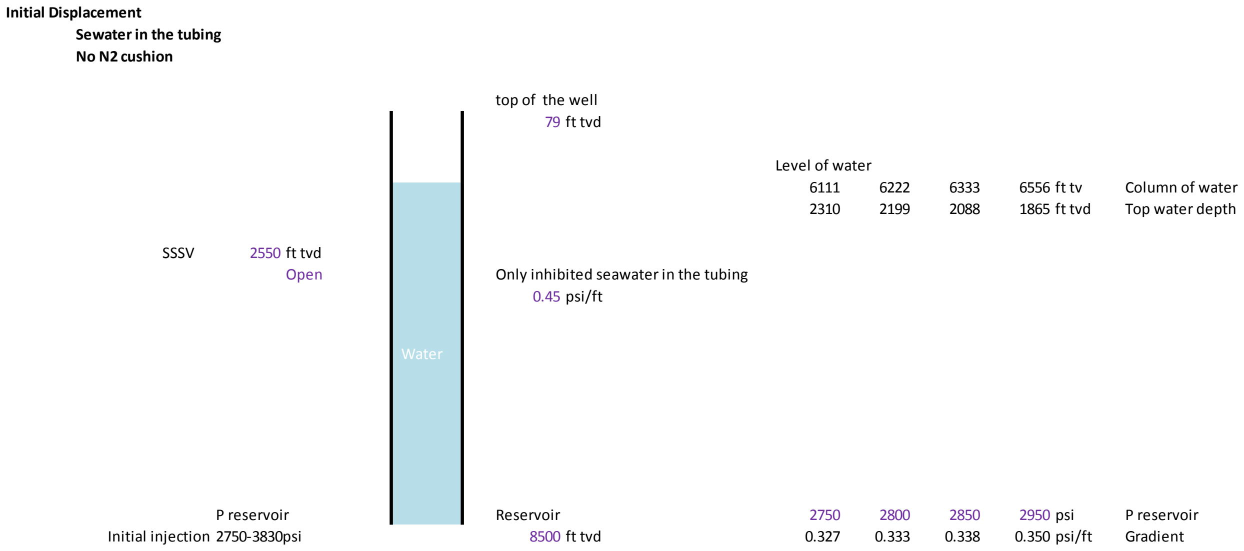


Figure 6-20: Initial Well Injection. Well conditions assuming only seawater in the tubing

The well can support a larger methanol (800 kg/m³, 0.35 psia/ft) column as opposed to water but not enough to obtain the 30 bara target tubing head pressure, Figure 6-21. The same is applicable for base oil where the density is similar to the methanol.

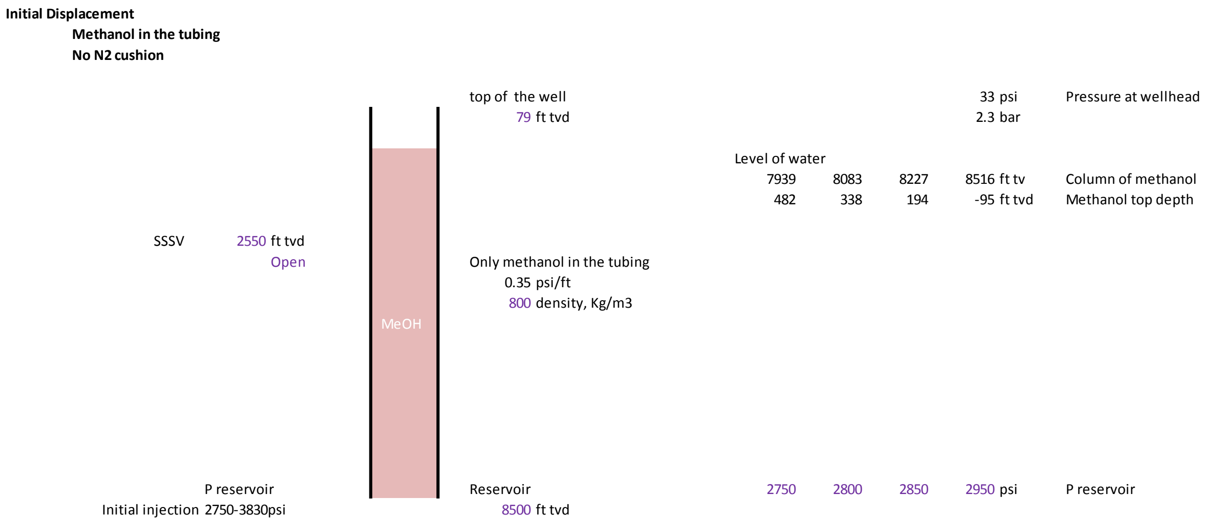


Figure 6-21: Initial Well Injection. Well conditions assuming only methanol in the tubing (methanol displacing all the water from the well)

To avoid hydrates during the initial injection it is required to pump methanol. A batch of 2500 ft TVD (equivalent to 37.3 bbl – 6.0 m^3) is required to be displaced before the initial injection, section 8.2.6. A N_2 cushion is required at the top of the well as a minimum pressure of 30 bara is required to avoid the JT expansion.

The estimated dimension of the methanol and the N_2 cushion is presented below, Figure 6-22, for the initial reservoir pressure. For the base case of 2800 psia reservoir pressure, the length of the required N_2 column is estimated at 2770 ft TVD, 2500 ft of methanol and the bottom part of the filled with inhibited seawater.

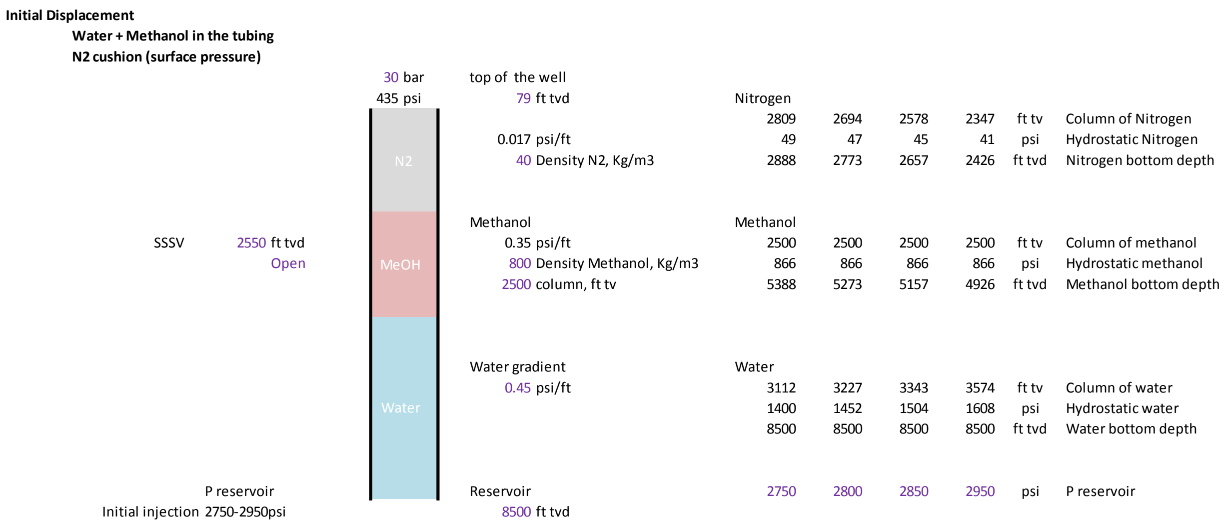


Figure 6-22: Initial Well Injection. Reference case: Using N_2 cushion and methanol.

The detailed procedure related to bringing a well on injection for the first time will be drafted in the following phases of the project.

7. Unplanned Conditions

7.1. Rapid Closure of a Well

Guideline: *Tree valves to be closed as soon as possible.*

This situation might be valid during emergency shutdowns.

Section 6.2 recommends closing the well in 30 minutes. Calculations were done in case of rapid closure of a tree valve in case of emergency, Figure 6-5 and Figure 6-6. The CO_2 temperatures generated under this scenario do not pose any integrity concerns to the well.

7.2. Malfunctioning Choke Situation

Guideline: *Identification by direct reading of CO_2 tubing head temperature.*

Once the problem has been identified then rapidly close the tree valves (section 7.3)

Two-hour window of injection under two-phase has been calculated not to have any issues for well integrity.

For the CCS project it is required to perform workovers with slim tubing due to CO_2 phase behaviour management and some aspects of well integrity (1).

Short excursions of low temperature during transient conditions (closing-in and starting-up operations, section 6.2 and 6.4) have been simulated and they do not pose a risk to the well integrity and operability of the project.

Once the well is worked over with the new slim completion, it is not acceptable to allow for continuous injection of CO_2 in two-phases due to cold temperature of the CO_2.

Two cases are evaluated after the well is normally closed-in at low reservoir pressures:

7.2.1. Very Low Injection Rate – Leaking Choke

This was simulated assuming 1 kg/s CO_2 injection (3.6 tonnes/h, 1.6 MMscfd) and represents a leaking choke, Figure 7-1.

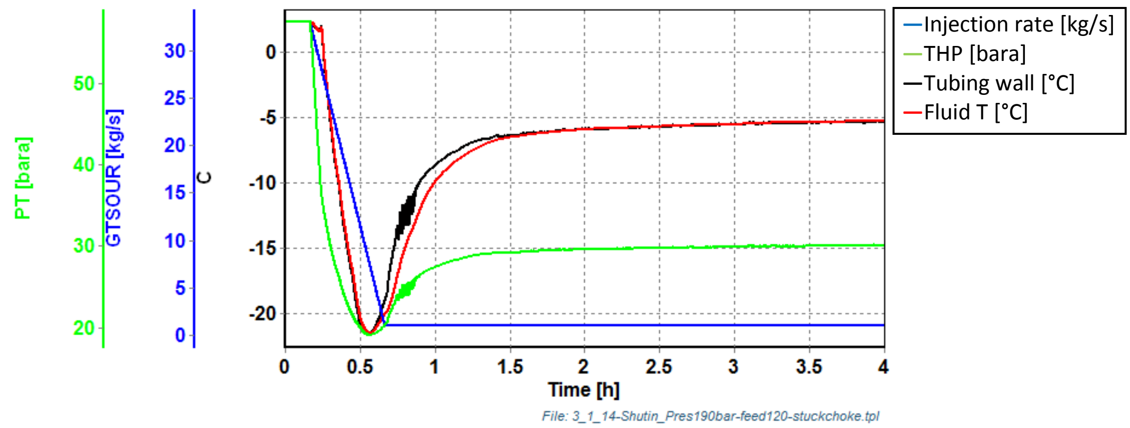


Figure 7-1: Wellhead conditions for a leaking choke at 4 t/h 1.6 MMscfd) after injection at 2750 psia [190 bara] reservoir pressure.

The dominating factor under this scenario is the reservoir energy over the JT expansion of the CO_2. With a very small injection rate the injection tubing head temperature is around 30 bara which is close to the CITHP. No issues are expected in terms of low temperature in a leaking choke scenario.

7.2.2. Stuck Choke – Significant Injection of Two Phases

Cooling of the well elements in the top of the well is expected when CO_2 is injected in two phases at a higher rate and low enough to create significant friction increasing the injection tubing head pressure. This will have an effect in the different well elements which can be translated into well integrity issues.

7.2.2.1. Simulation of Well Conditions

For the purpose of this simulation, CO_2 is injected in two phases in the top of the well for a long time with a CO_2 temperature in the order of -23°C at the tree level (worst case). This might be associated with a 'stuck' choke event. Results for the worst case reservoir pressure of 2750 psia are presented in Figure 7-2:

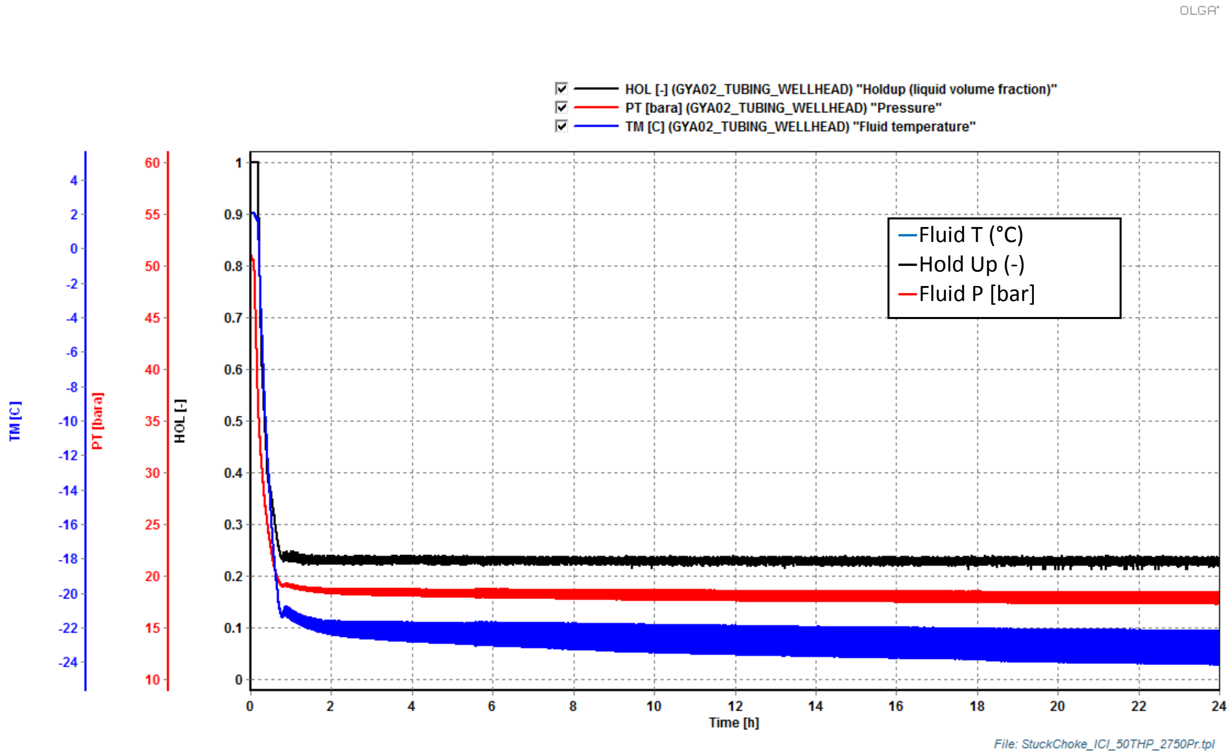


Figure 7-2: Long time injection under two CO_2 phase scenario for low reservoir pressure (2750 psia – 190bar). Tubing head conditions.

Injecting continuously at this temperature will lead to numerous risks to well integrity and operability (possibility of wellhead brittle fracture, freezing of the B-annulus fluids, hydrates and seabed freezing).

It must be noted that higher CO_2 temperatures will be obtained under two-phase flow or a stuck choke scenario for higher reservoir pressures.

Identification of two-phase injection is important. This can be identified with direct tubing head temperature sensors. In addition, the CO_2 temperature can be inferred by tubing head pressure sensors.

7.2.2.2. Well Integrity Issues

7.2.2.2.1. Wellhead

The class U wellhead system installed in Goldeneye wells is qualified to -18°C. The weight and tension of the tubing is supported by the tubing hanger which sits in the wellhead equipment.

According to the vendor (Cameron) the same material is used for API 6A class 'K' (-60°C rated) equipment. As such, there is uncertainty around the occurrence of brittle fracture of the system if the temperature in the wellhead is at -23°C with continuous injection of CO_2.

The wellhead is not in direct contact with the CO_2 but the tubing hanger and the wellhead system are in metal contact. The tubing hanger can be changed to -60°C but the rest of the wellhead system cannot be economically changed. The temperature at the wellhead system was calculated using CFD for a stuck choke situation.

In the 8 hour CFD simulation with CO_2 flowing at -23°C of the CO_2, the temperature at the wellhead system did not reach -18°C. Below (Figure 7-3), a snapshot at 8 hours of the CFD modelling where -23°C is applied in the internal part of the tree/wellhead system. The top part of the graph (blue) represents the new tree which will be qualified to -60°C and hence is not an issue.

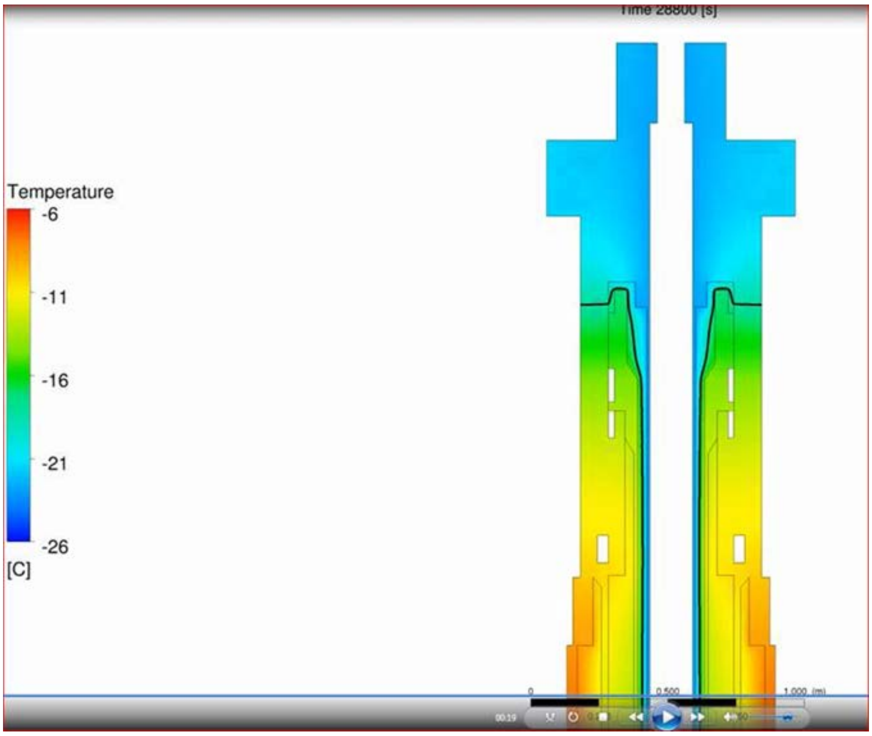


Figure 7-3: CFD temperature results on the wellhead system after injecting CO_2 at -23°C for 8 hours

In summary, simulations indicated that for 8 hours continuous injection under two-phase flows, the temperature of the wellhead will not reach the current limitation of the equipment.

7.2.2.2.2. Hydrates

In a two-phase injection (below the minimum rate) the CO_2 will still be injected within the fluid component specification conditions.

For the water specification of the CO_2 (20 ppm weight / 50 ppm mole) the hydrate formation boundary is found at the intersection with the boiling curve of CO_2 at a temperature of -22.1°C and a pressure of 18.4 bara, Figure 8-1 and Figure 8-2. Ice forming is at -43°C, Figure 8-2. This means that below a temperature of -22.1°C and 18.4 bara hydrate crystal in theory may be formed.

However, it is not expected to create issues in the well due to:

- The amount of gas hydrates will be very low even for excursions into the hydrate conditions due to the small amount of water in the stream specification. With the maximum CO_2 injection rate of 138.3 te/h, the water flow rate would only be 0.00077 dm^3/s. With a conservative assumption that all the water is captured into hydrates (density of 1470 kg/m^3), it would take about 11 minutes to collect enough material to form a hydrate sphere-shaped seal with a diameter equal to the wellbore diameter (3.9 inch).
  For smaller rates, then the amount of time allow to have excursions below the Hydrate Equilibrium Temperature (HET) is longer; using a simple proportionately rule:
  Maximum rate – 11 minutes
  114 tonnes/h – 14 minutes
  50 tonnes/h – 30 minutes
  10 tonnes/h – 160 minutes
- The velocity of the injected fluid and the vertical and near vertical downward flow will limit the agglomeration of hydrates.
- Formation of hydrates is a stochastic process and with only 1°C in the hydrate formation regime, the rate of formation of hydrate crystals will be low.
- Hydrates crystals will be melted when traveling down the tubing as the temperature and pressure will increase again.

From the discussion above, in theory, hydrates can be formed under a stuck choke scenario even if the CO_2 is at specification condition in terms of water; however, the ability of the hydrate crystal to stick together and form a plug is difficult to envisage.

The CO_2 will reach the Hydrate equilibrium temperature of -22.1°C after injecting for two hours under the worst case conditions. It does not mean hydrate deposition as discussed above, but this time will be used to limit the two-phase injection into the wells; again a very conservative approach.

The consequences of hydrate agglomeration in a stuck choke scenario would involve the melting operations of the formed hydrate in the top of the well. No well integrity issues are expected as the SSSV will be positioned in the well where the CO_2 temperature would be higher than the hydrate equilibrium temperature.

7.2.2.2.3. Seabed Freezing

Under a two-phase steady state injection scenario (low temperature), sub-zero CO_2 temperatures will be encountered to well depths of 2100 ft.

The injection time to create freezing conditions in the C-annulus (-2°C) is calculated at 11 hours. Clearly, other potential issues would appear before the freezing of the seabed.

7.2.2.2.4. Other Well Elements

Other well elements (tubing, tree, tubing hanger, A-annulus fluid, control line fluid, hydraulic fluid, etc.) in the top of the well (where the 2 phase injection would occur) will be rated to temperatures below -23°C.

The CO_2 temperature at the SSSV level is about 8°C for injection below the minimum rate. It is not expected that the valve is blocked by hydrates under a stuck choke scenario as the CO_2 is still injected at the CO_2 specification, Figure 7-4.

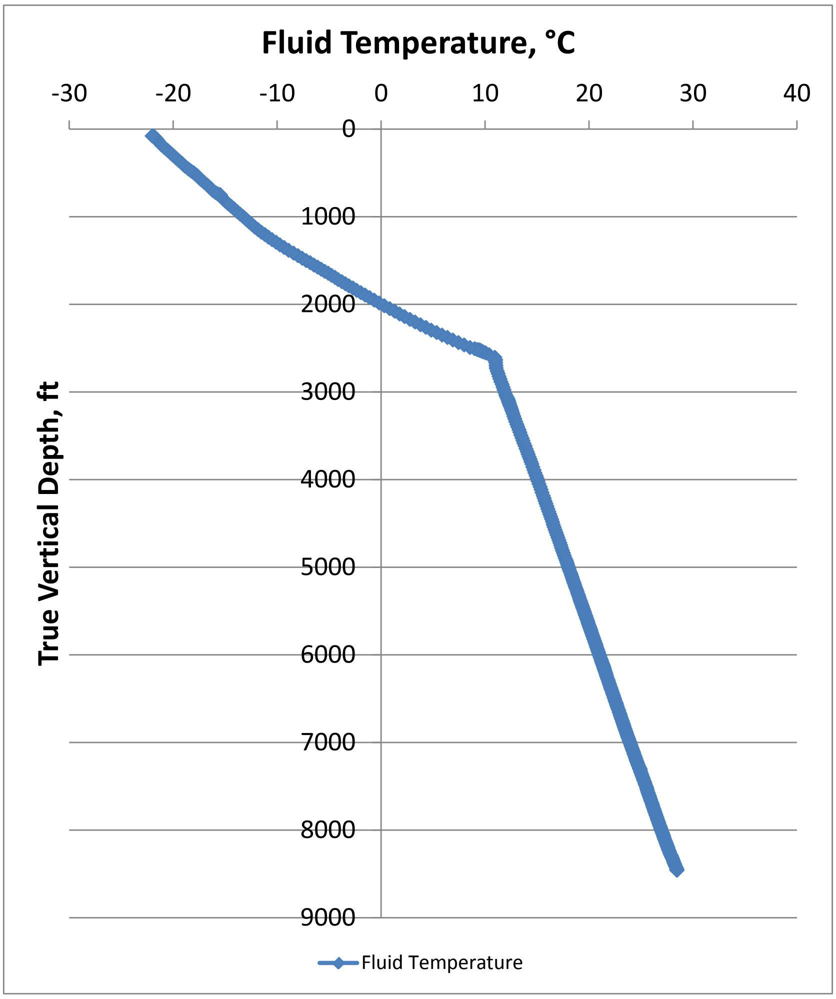


Figure 7-4: Fluid Temperature during a long term stuck choke scenario injecting the CO_2 in two phases. 2750 psia – 190bar reservoir pressure. Temperature at 24 hours in Figure 7-3.

Bottom hole injection temperatures in a stuck choke scenario would be similar (or even higher) to the expected temperature in the case of injecting in liquid phase in the top of the well (reference case) due to the small velocity of the CO_2 in the tubing. No hydrates or ice are expected at reservoir level.

7.2.2.3. Solution to Stuck Choke Scenario

The solution for this scenario is to close the well using a tree valve in a short period of time once the problem is identified.

A system will be installed in the platform which will include multiple sensors (temperature), The UMGV or WV will be closed automatically when the CO_2 temperature is below -7°C for 2 continuous hours to avoid any of the potential issues discussed above. If the Temperature at the tree recovers the timer is only reset after 60 minutes above 0°C.

7.3. Stuck Choke Situation and Rapid Closure of the Well

Guideline: *Once the problem has been identified then rapidly close the tree valve.*

This operation will not create excessive low temperatures in the top well elements.

In case of having a stuck choke, the well is required to be closed as soon as possible using the tree valves and within the two hours of this scenario occurring. No significant changes in temperatures of the CO_2 stream are observed during this scenario, Figure 7-5.

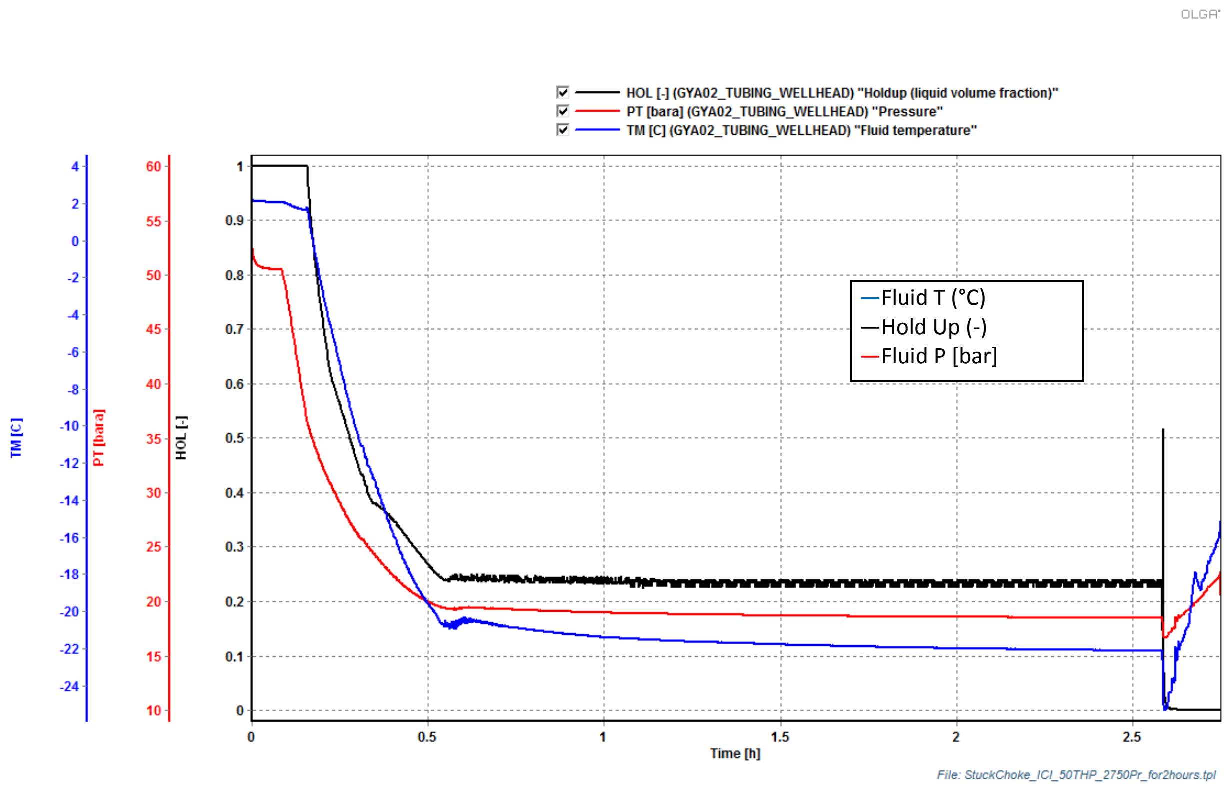


Figure 7-5: CO_2 conditions for an emergency shutdown after 2 hours of two-phase injection for low reservoir pressure.

7.4. Re-starting a Well When Tubing Head Pressure Is Above 120 bara

Guideline: *In case of having a CITHP higher than 120 bara (maximum CO_2 available pressure at the tubing head)*

Inject methanol into the well to reduce the tubing head pressure to 80 bara level (with an absolute minimum of 30 bara)

Introduce the CO_2 into the well once the tubing head pressure is around 80 bara.

Care is required for not over displacing methanol into the well when the reservoir pressure is low to avoid issues regarding JT cooling by re-introducing the CO_2.

This case is valid in case there is hydrocarbon gas in the tubing. The CITHP for a well filed with hydrocarbon gas will be higher than the maximum available pressure of the CO_2 at the platform (~120 bara) as such there will not be enough available pressure to inject the CO_2 into the well. The same problem will occur in case of having the well filled only with N_2.

Methanol available at the platform can be injected into the well to decrease the tubing head pressure to levels where the CO_2 pressure can recommence the injection.

The hydrostatic pressure of a well fully filled with methanol is estimated at 2920 psia. For low reservoir pressure care is required for not over displacing methanol into the well as the tubing head pressure can be reduced to atmospheric levels with negative consequences of JT cooling in the top of the well when CO_2 is introduced. To avoid this, once the tubing head pressure is close to 80 bara during the methanol injection then the CO_2 can be introduced into the well.

The absolute minimum tubing pressure is estimated at 30 bara, required to minimise the JT expansion (saturation temperature of -5.5°C).

Methanol over injection into the well is less of a concern for high reservoir pressures as the minimum tubing head pressure of 30 bara will be obtained even with a well full of methanol. This is calculated for reservoir pressures higher than 3355 psia (2920 psia hydrostatic pressure of a well filled with methanol + 30 bara tubing head pressure).

The required volume of methanol to be injected into the well is variable depending on the downhole conditions (reservoir pressure) and how effectively the methanol will inject the hydrocarbon gas in the well. At the end, the procedure can be managed with the suggested tubing head pressure.

The CITHP of a well filled with methanol at the maximum reservoir pressure of 3830 psia is estimated at 910 psia. This indicates that at the highest expected reservoir pressure it is possible to re-start the well with the CO_2 once the well is injected with methanol.

This operation requires pressurising the methanol supply to the required pressure. The methanol supply must be started up from St Fergus and it will take around 2 hours to pressurise the methanol line sufficiently.

7.5. Re-starting a Well When Tubing Head Pressure Is At Atmospheric Conditions (SSSV Closed)

Guideline *Inject immediately 4 m³ of methanol after the problem has been identified. This is to avoid extreme JT cooling across the SSSV.*

Assess individual cases to equalise pressures across the valve and re-commence injection. It will depend on the reservoir pressure and the temperature conditions.

The operation might involve extra methanol injection, the use of CO_2 and possibly the installation of a N_2 cushion.

Waiting for the well to warm up will help to reduce the JT cooling when CO_2 is re-introduced into the well.

This scenario is unlikely if the operation guidelines are followed for the testing of the SSSV, section 6.5 where it is recommended to bleed-off the tubing head pressure to a minimum of 24 bara or by an incident at the tree level (release to atmospheric conditions).

Under this scenario, liquid CO_2 will be below the SSSV and gas CO_2 at close to atmospheric pressure will be above the valve. The flapper valve can only be opened when the pressure from above and below are the same (pressure equalisation). Ideally, control line pressure should be applied to keep the valve open once the pressure has been equalised. At this moment of time, injection can be resumed.

As a worst case, it is assumed that the tubing head pressure control failed leading to a pressure of 1 bara. Theoretically, the CO_2 can reach temperatures of – 78.5 °C.

7.5.1. Open the Valve by CO_2 Injection

This case was simulated in OLGA (a check valve is used for this simulation) with the following results, Figure 7-6:

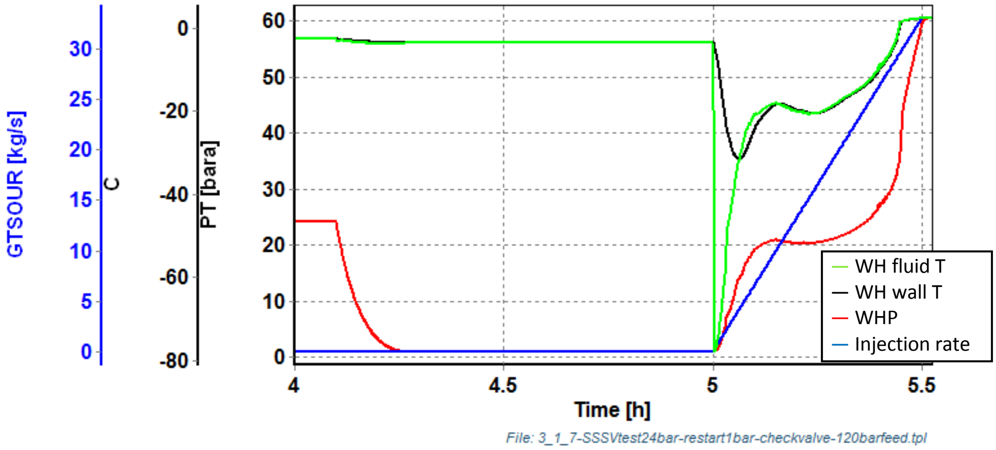


Figure 7-6: Re-start of injection for a well with atmospheric tubing head pressure and SSSV closed using CO_2 for low reservoir pressure scenario and cold well after injection

Starting up at low Wellhead Pressure (WHP) leads to very low fluid temperatures (-77°C) for a very short period of time (<1-2 minutes) and wall temperatures of -30°C for a very short period of time. Note, however, that wall temperatures are below -18°C for less than 15 minutes.

Due to the very transient nature of this procedure, the equipment of the well is not affected considering the calculated wall temperature of -30°C for a short period of time. The tree and tubing is designed to sustain even lower temperatures.

The temperature at the SSSV stays above freezing conditions during this operation due to the distance between the tree and the SSSV and the pressure required to open the SSSV.

This procedure is not ideal as the pressure equalisation across the valve is not followed by the pressurisation of the control line. This might lead to damage to the SSSV seal face over a prolonged period of injection. Over short period of injection time this procedure is considered safe; as such, injection can be stopped as normal (section 6.2) and control line pressure can be applied to re-start with the injection.

7.5.2. Equalise the Valve Using Methanol

See section 8.3.7

8. Hydrate Inhibition

Hydrates will be managed primarily during steady state injection by dehydration of the injection fluids to sufficiently remove the water to inhibit the formation of hydrates. The specification of 20 ppm weight (50 ppm mol or 0.005 mol %) of water into the export pipeline at Peterhead is based on the requirement that during normal injection and during start-up/shut-in hydrate formation is prevented.

During hydrocarbon production, water has encroached into the Goldeneye gas hydrocarbon section and at least part of the well gravel pack will be surrounded by water when that injection commences. As such hydrocarbon gas and water will be present during the initial CO_2 injection. 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. Exceeding the normal water specifications in the CO_2 will increase the hydrate risks considerably, especially during start-up and shut-in operations.

The following risks were identified for non-steady state operations with the above specification of the CO_2 stream:

- Start-up of the production at an initial pressure below 20 bara at the top of the well.
- Start-up after a well intervention.
- Testing of the Sub-Surface Safety Valve (SSSV).
- Initial start-up of CO_2 injection.

8.1. Gas Hydrate Behaviour in the System CO_2 and Water

A mixture of CO_2 and water will form crystalline solids or gas hydrates under certain pressure and temperature conditions.

For a water concentration of 0.005 mol % the maximum is found at the intersection with the boiling curve of CO_2 at a temperature of -22.1°C and a pressure of 18.4 bara. The Hydrate Equilibrium Temperature (HET) is depending on the amount of water in the system, Figure 8-1.

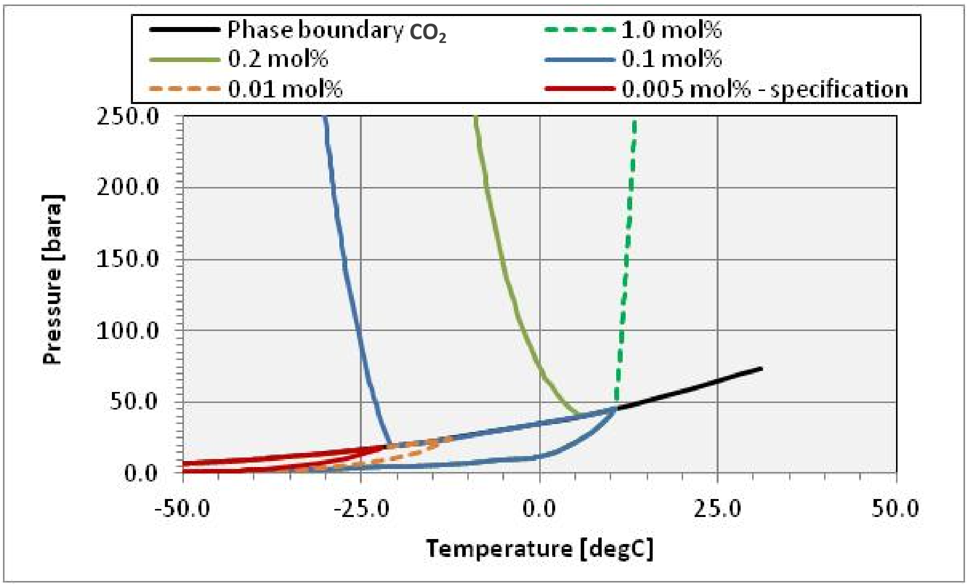


Figure 8-1: Gas hydrate phase boundaries for the CO_2+water system for different concentrations of water (water specification for Peterhead CCS is 0.005 mol %)

In addition to the hydrate equilibrium temperature the dew point line for water and the ice phase boundary was calculated for a water concentration of 0.005 mol %. The low concentration of water has a large impact on these phase boundaries. Figure 8-2 shows that the water dew point takes place at a lower temperature than the hydrate equilibrium temperature below the boiling curve of CO_2. The intersection of the phase boundary line with the boiling curve is at -28.2°C and 15.2 bara. Ice formation of water takes place below -43°C and 1.9 bara.

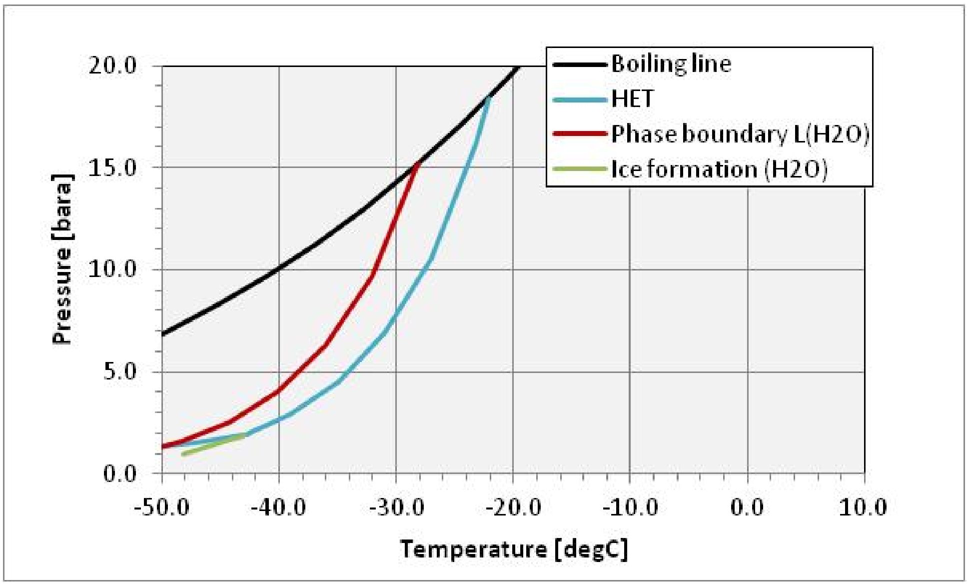


Figure 8-2: Hydrate Equilibrium Temperature (HET) and the water dew point line for 0.005 mol % of water in CO_2 below the boiling curve for CO_2

In the presence of free water it is possible to form hydrates when the temperature is below 13.4°C at high pressures, Figure 8-1. Under injection conditions this corresponds to a depth in the well of approximately 1800 m [5900 ft]. In theory, injecting a hydrate inhibitor above this depth will solve all the issues related to hydrate. However, hydrostatic pressure considerations are required to avoid excessive JT cooling in the top of the well when the tubing head pressure is relatively low.

The well will warm up during the closed-in operation. The 13.4°C will be encountered at a depth of approximately 450 m [1480 ft]. Any hydrate plug formed below this depth will be melted by the heat of the formation.

8.2. Hydrate Formation Risks

8.2.1. Injection Conditions

Meeting the specification that less than 20 ppm weight (50 ppm mol or 0.005 mol %) of water in the export from the compressor at the carbon capturing plant at Peterhead is sufficient to ensure that hydrates do not form during normal steady-state and shut-in operations.

Even during short excursions into the hydrate formation conditions, a water content of 20 ppmw will result in very little gas hydrates. At the maximum CO_2 injection rate of 137 t/h, the water flow rate would only be 0.00077 dm^3/s. With a conservative assumption that all the water is captured into hydrates (density of 1470 kg/m^3), it would take about 700 s to collect enough material to form a hydrate sphere-shaped seal with a diameter of which being equal to the wellbore diameter (3.9 inch). Therefore, it can be concluded that operating inside the hydrate formation conditions for short periods (e.g. 10 minutes) will not lead to any operational difficulties with respect to hydrate formation with a water content according to the specifications.

From Figure 8-3 it can be concluded that during normal injection operations (section 5), the wellbore is operating well outside the hydrate region and no issues are foreseen regarding hydrate formation.

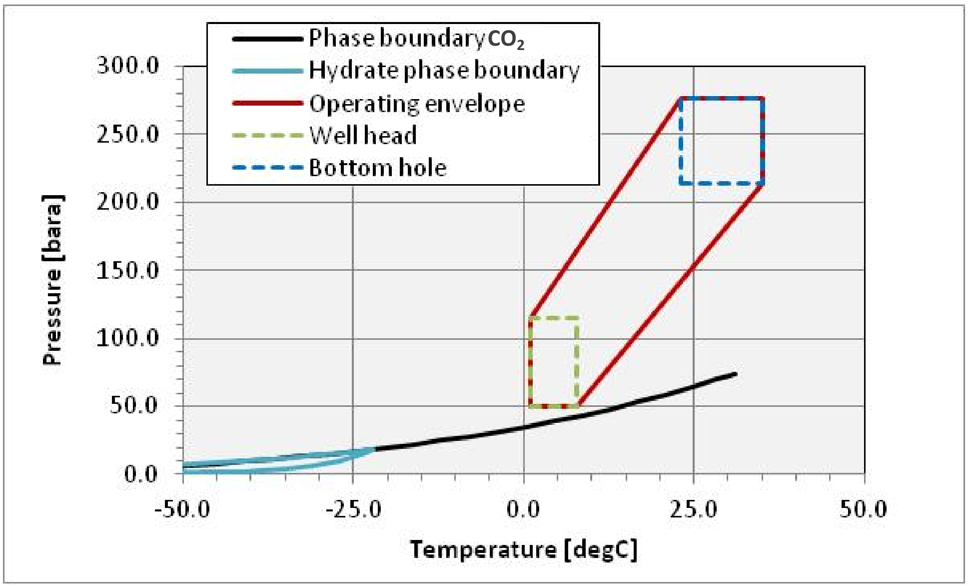


Figure 8-3: Operating envelope of temperatures and pressures in the well tubing during steady-state operations

The injection well will develop cold conditions, the bottom hole injection temperature during normal injection are expected to be between 23°C to 35°C as such there is not an issue of hydrate deposition in terms of injectivity.

8.2.2. Closing-in Operation

The well is still injecting CO_2 during the closing-in operation as such there is no aquifer influx yet. The bottom part of the well is not in the region to form hydrates.

During the closing-in operation the well is still injecting CO_2 at the specification. Under the recommended time to carry out the closing-in operation there is not risk of hydrate deposition, Figure 8-4. The well will not operate inside the hydrate region for the simulated cases considered in Section 6.2 (the CO_2 temperature is below the HET of -22°C for a water concentration of 0.005 mol %, which is the maximum water specification of the CO_2 stream from Peterhead)

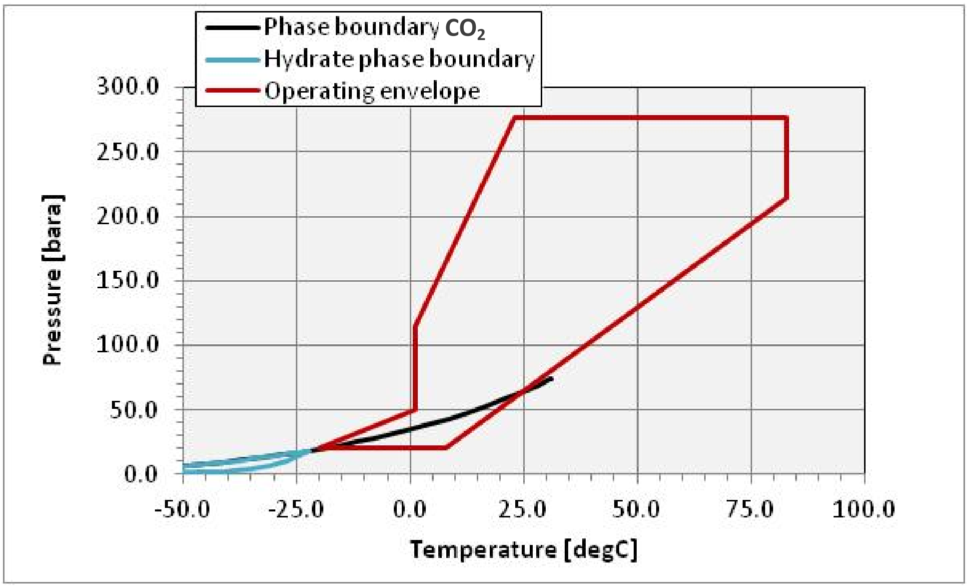


Figure 8-4: Operating envelope of temperatures and pressures in the wellbore during shut-in, start-up operations and a prolonged shut-in

Even entering the hydrate formation conditions for short periods will not lead to any issues at the top of the well because of the low amounts of water in the CO_2 stream. Before shut-in, the available and fully distributed water in the whole well tubing will be less than 400 g. This amount will be not enough to form a complete blockage as a full blockage requires at least 700 g of water.

8.2.3. Closed-in Period

The well will be warming up during this time and will tend to go into the geothermal conditions. The bottom part of the well will be at temperatures above the hydrate equilibrium temperature even assuming free water.

The top part of the well will be warming up, but the pressure and temperature conditions will stay in the hydrate curve assuming free water.

The main uncertainty during this period is the presence of free water in the well. Water has been observed in the existing closed-in wells. However, with increased injection of CO_2, water from the aquifer is pushed away by the CO_2. The time where the water is not coming back into the well is closed-in is estimated after six months to one year of continuous injection. After this continuous time of injection the water will tend to stay away from the wellbore. However, in case that the well has been injecting for a short time then it is possible that water may enter the wellbore.

Displacement of the well inventory with the saline formation water (density of 1029 kg/m^3) is unlikely as the density differences between formation water and the dense CO_2 will prevent upward flow. However, CO_2 may dissolve in the water phase at the interface between dense CO_2 and the formation water. This may result in a slow upward movement of the CO_2-water interface in the well tubing. The transport of CO_2 to the brine phase depends on the pressure, the temperature and the total amount of dissolved solids in the brine. Dissolution of CO_2 is not only governed by the diffusion process, with higher concentrations of CO_2 in the dense phase-water interface with increased pressures, but also natural convection will take place in the brine that will enhance the mass transfer of CO_2 into the brine.

As the temperature of the well fluids in the bottom part of the tubing (23°C to 35°C when injecting CO_2) is above the HET (13.4°C at 250 bara with an excess of water (conservative)), no hydrate conditions are foreseen with additional water inflow from the reservoir into the bottom of the well. According to the most conservative case, a temperature of 13.4°C will be reached at a depth of 1800 m, which is at least 800 m from the reservoir inflow. Furthermore, the salinity of the water inflow from the reservoir will shift the hydrate formation conditions to lower temperatures.

8.2.4. Starting-Up Operation

For the start-up of the CO_2 injection, one should be aware that hydrate formation may occur. This also means that the history of events after shut-in is important.

In order to reduce the initial risk of hydrate formation during the first years of injection, (aquifer water has not been fully displaced from the wellbore) it is considered prudent to introduce batch hydrate inhibition prior to operational opening of a well for injection.

When starting the injection after a normal shut-in during which (without intervention or changing the content of the well tubing) the wellhead pressure tends to decrease below 20 bara. It is advised to inject a hydrate inhibitor during start-up because the well may operate at temperatures below -22°C (inside the hydrate formation condition for the water specification of 0.005 mol %). Hydrates, when formed may accumulate as continuously small amounts of water are injected into the well. No hydrate formation risks are foreseen if the wellhead pressure is higher than 20 bara before start-up.

In all other cases, it is advised to inject a hydrate inhibitor during start-up, as the content of the tubing may contain more water than the specifications given for the project and accordingly an increased risk of a hydrate blockage may exist.

8.2.5. Testing of the SSSV

Low temperatures can be encountered during the depressurisation period. In case that the testing is done immediately after closing the well from injection then it is not required to inject methanol into the well as the CO_2 will be under specification conditions and the lowest observed temperature is -7°C outside if the hydrate deposition window.

Methanol is required to equalise the pressures across the valve to be able to open it once the test has been completed.

8.2.6. Initial Start-up of Injection

Before the initial start-up of the CO_2 injection, the well tubing will contain large amounts of water from the reservoir or from the well intervention. This amount of water may cause an issue when cold CO_2 enters the tubing during the initial start-up. This needs to be addressed by injecting hydrate inhibitor in the well.

8.2.7. Starting-Up After a Well Intervention

The fluids after a well intervention may have changed considerably and may contain large amounts of water. When starting the injection of CO_2 with a low tubing head pressure, the interface of the fluids in the well tube may become in direct contact with a cold stream of CO_2.

These conditions will be clearly in the hydrate formation regime, Figure 8-1, and need to be addressed in the remediation measures in order prevent hydrate formation to occur.

8.3. Hydrate Avoidance Guideline

8.3.1. Preferred Inhibitor

Guideline *Methanol*

Part of the remediation will consist of injecting a hydrate inhibitor. In this case, a thermodynamic hydrate inhibitor like methanol or MEG/water, needs to be used. Methanol is the recommended inhibitor to be used, because of the low temperatures it may become exposed to with CO_2 (e.g. during a depressurisation). The freezing point of MEG/water depends on the percentage of MEG. The minimum freezing temperature is about -50°C

8.3.2. (Steady State) Injection Conditions

Guideline *See section 8.2.1*

8.3.3. Closing-in Operation

Guideline *See section 8.2.2*

8.3.4. Closed-in Period

Guideline *Inject 6.0 m^3 of methanol in the well during this period when the following conditions are met:*

- injection time in the well of less than 2 years

- Closed in period of more than 24 hours

The well is closed-in and it is warming up during this time. The bottom part of the well is warm even after injection and hydrates are not expected. There is uncertainty in the presence of water in the top part of the well where it is cold and temperatures are below the HET for the free water case.

The well needs to be prepared for the re-introduction of CO_2 and avoid potential hydrate deposition.

The introduction of methanol is required considering the following cases:

- During the initial stages of injection where the CO_2 plume is not developed and water from the aquifer might be in contact with the well. It can take after 2 years of injection for the water not to come back into the well
- Even with the presence of the water in the well it is possible that the water does not reach the top of the well. Temperature below 15°C (HET temperature for high pressures) can be encountered above ~4500 ft TVD in the well. It is unlikely that under short term closed-in periods the water will be able to travel from the reservoir to 4500 ft TVD in the well. Diffusion and convection process are slow.
  It is proposed to displace methanol during a normal start-up if the well is closed-in for more than 24 hours. This is considered a very conservative time.

In case of having injected in a well for a long time where a CO_2 plume is formed then methanol is not required to be injected into the well. One might argue that is better to standardise the starting up operation for all the cases and methanol is required. This can be decided during the operational phase of the project where more experience will exist in the management of the wells.

8.3.5. Starting-Up Operation

Guideline *Methanol has been injected into the well during the closed-in period as such hydrates are not expected* *into the well*

8.3.6. Normal Testing of the SSSV

Guideline *Inject 6 m^3 of methanol after the SSSV test*

Evaluate displacement pressures

Depending on displacement pressure it is possible that more methanol pumping is required to equalise the pressures across the valve (valid for a well full at geothermal conditions)

Apply control line pressure

Re-commence injection

After a SSSV test, injection will need to re-commence. Section 6.5.3 indicated the well conditions of the operation of opening the valve using only CO_2. The top part of the well will be at 24 bara as described in section 6.5 , Figure 8-5.

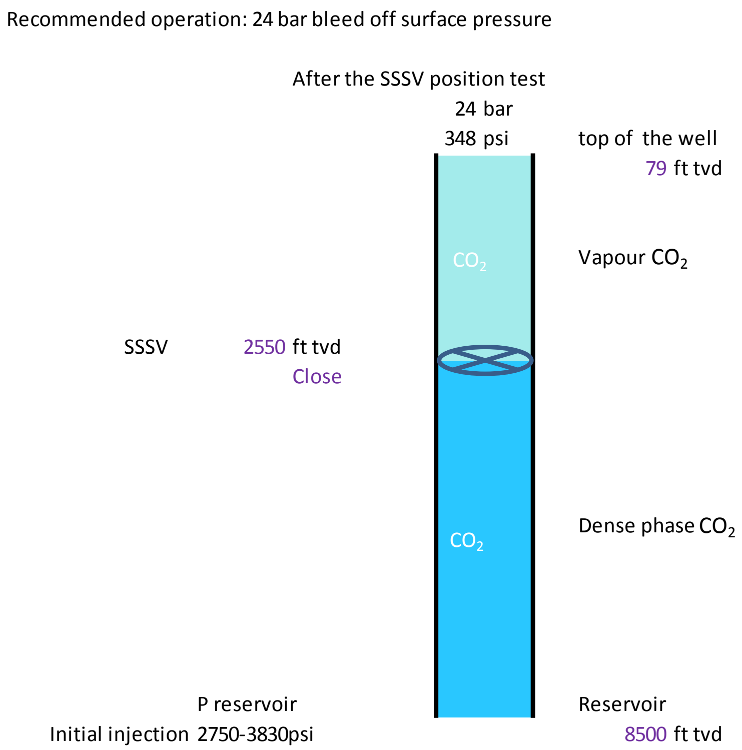


Figure 8-5: Well Conditions after a normal SSSV test

The pressure from below the valve are given by the well conditions are variable and depending mainly on the reservoir pressure and the temperature in the well, Figure 8-6.

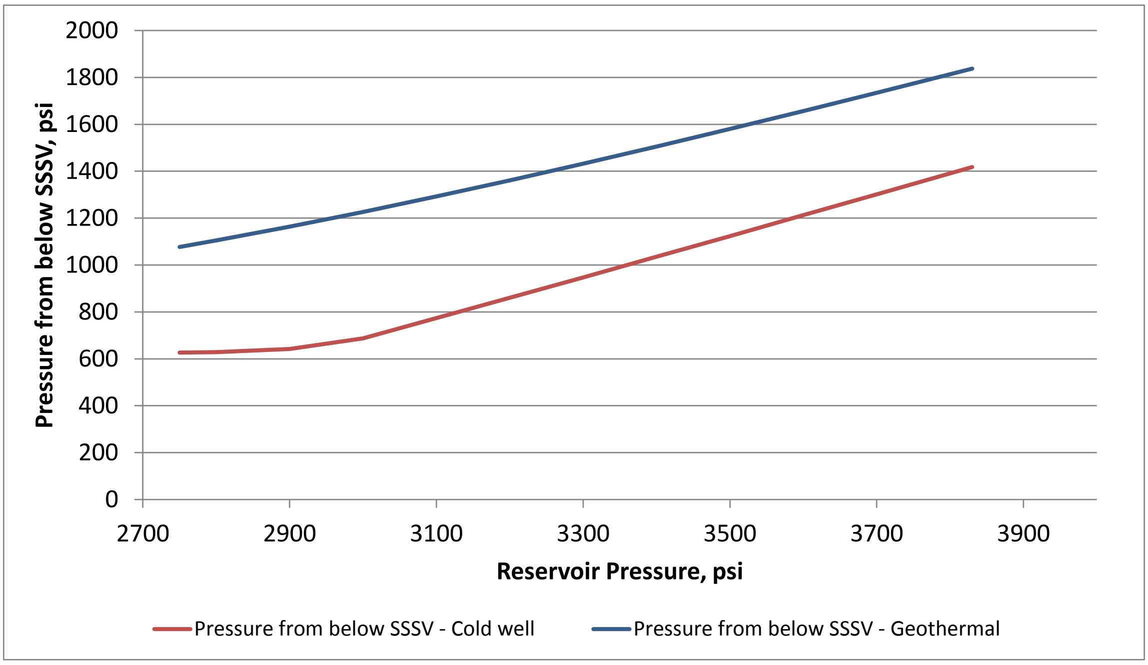


Figure 8-6: Pressure from below the SSSV for a static well

The hydrostatic pressure of a full column of methanol between the tree and the SSSV is estimated at 856 psia considering the density of the methanol (~800 kg/m^3). The 24 bara CO_2 above the SSSV in the well will stay in this section of the well until the pressure is equalised; then the pressure above the valve should consider the 24 bara tubing head pressure, the hydrostatic head pressure of the CO_2 above the valve (~60 kg/m^3) and the amount of methanol pumped into the well (hydrostatic head of the methanol and volume reduction of the CO_2).

In the case of pumping only a 500 m column of methanol, then the pressure from above the valve will not be enough to equalise the pressures across the valve and being able to open it, especially in the case of a geothermal well, Figure 8-7. For a cold well and reservoir pressures of less than ~3000 psia it would be possible to equalise the well. It is clear that a bigger amount of methanol will need to be injected into the well to be able to equalise pressure across the valve.

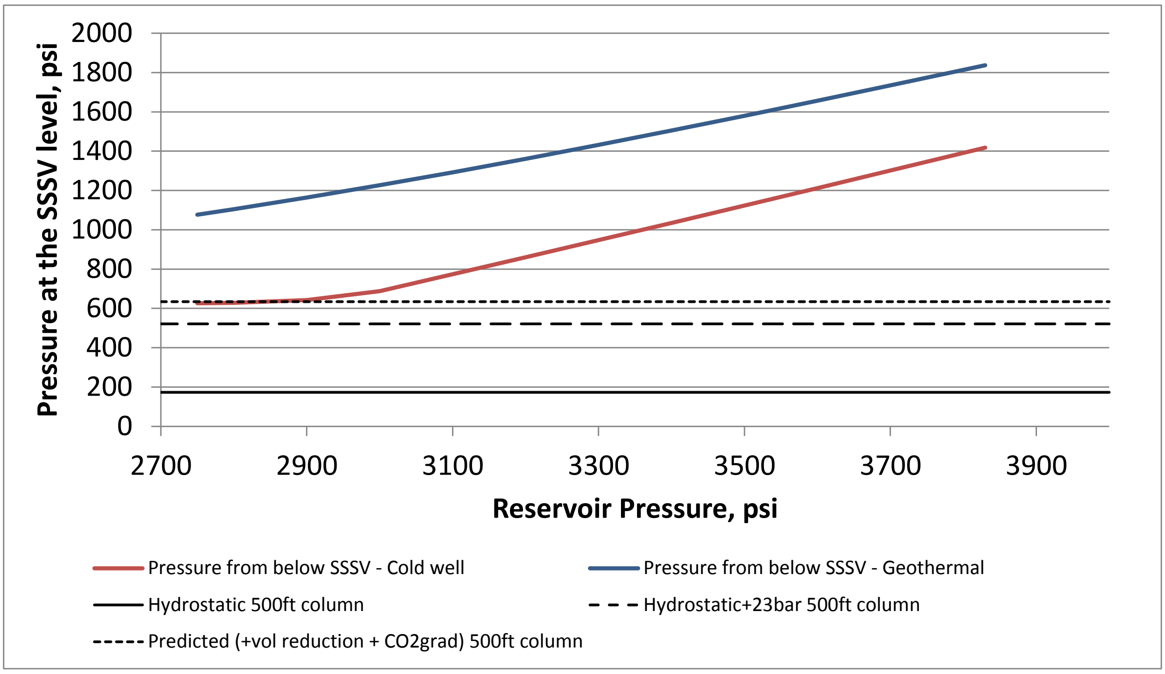


Figure 8-7: Pressures at the SSSV in case of displacing a 500 ft column of methanol after a normal testing of the SSSV

Injecting the full column of methanol between the tree and the SSSV will be required in most of the cases to open the valve, Figure 8-8. Note that the change of CO_2 phases is not captured in the previous due to the complexity of the process. However, it can be observed that for low reservoir pressures and even under geothermal conditions it would be possible to equalise the pressures across the valve. For geothermal conditions, and high reservoir pressures (>~3000 psia), it would be required to increase the tubing head pressure by using methanol injection into the well to be able to increase the pressure from above the valve. Indication of equalisation will be observed on the tubing head pressure whilst pumping methanol.

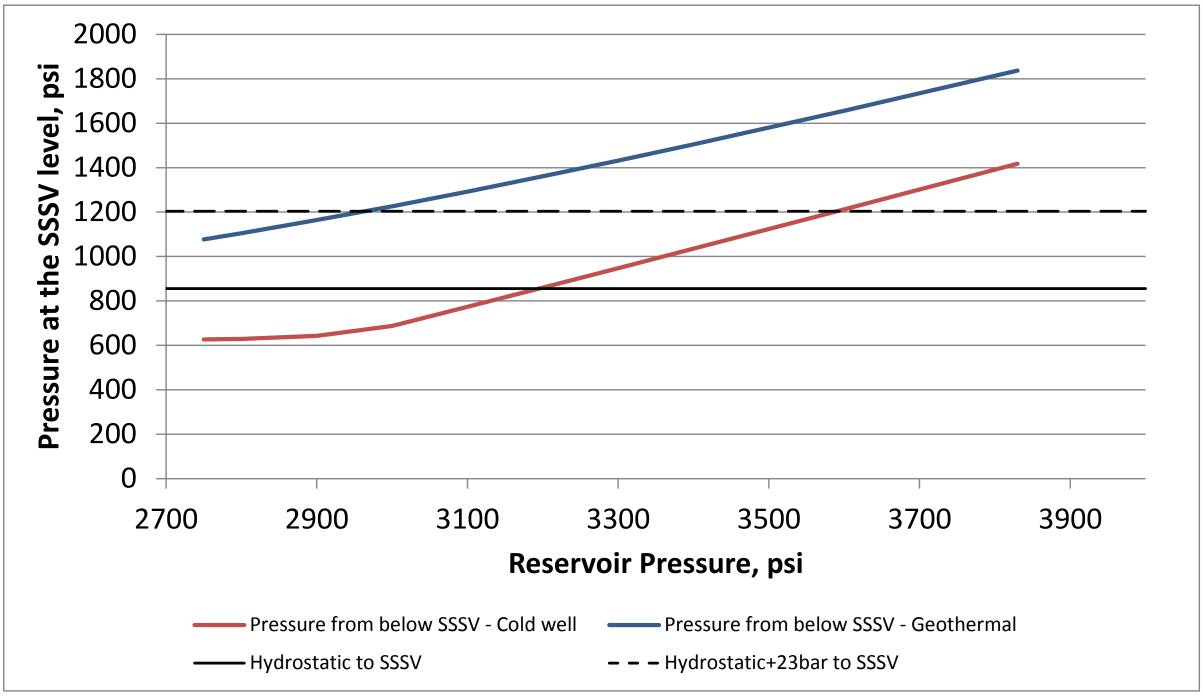


Figure 8-8: Pressures at the SSSV in case of displacing a full column of methanol between the tree and the valve after a normal testing of the SSSV

Once the SSSV is open the whole well is connected to the reservoir. Apply pressure to the control line. And re-injection can commence.

Care with the injected volumes into the well is required especially at low reservoir pressures where a full injection of methanol into the well will lead the tubing head pressure to be at atmospheric conditions due to the high hydrostatic pressure of the methanol (2920 psia).

8.3.7. Re-starting the Well In Case Of Excessive Bleed-off Pressure after a SSSV Test Using Methanol

This case is important due to the very low pressures above the valve in comparison to the normal procedure. This is not a planned operation. Care in the operations will be required to avoid bleeding-off to atmospheric pressure during the SSSV test. An automatic pressure valve is recommended for this operation, section 6.5.1.1.

Under this scenario of atmospheric bleed-off pressure above the SSSV, practically the CO_2 above the valve will not generate any hydrostatic pressure due to the low CO_2 density and hence this pressure is close to atmospheric conditions. To avoid the extreme cooling across the valve and adjacent to it, it is required to pump methanol immediately after the problem has been identified.

It is recommended to pump methanol between the tree and the SSSV. This will increase the pressure from above the valve to minimise the JT cooling. A minimum of 40 bara pressure above the valve (boiling/saturation point temperature of 5.3°C) is required. This is equivalent of pumping a methanol column of 1680 ft column, or 4 m^3 of methanol. The tubing head pressure after injection will be above atmospheric conditions at around 4 bara due to reduce volume of CO_2 when the methanol is pumped.

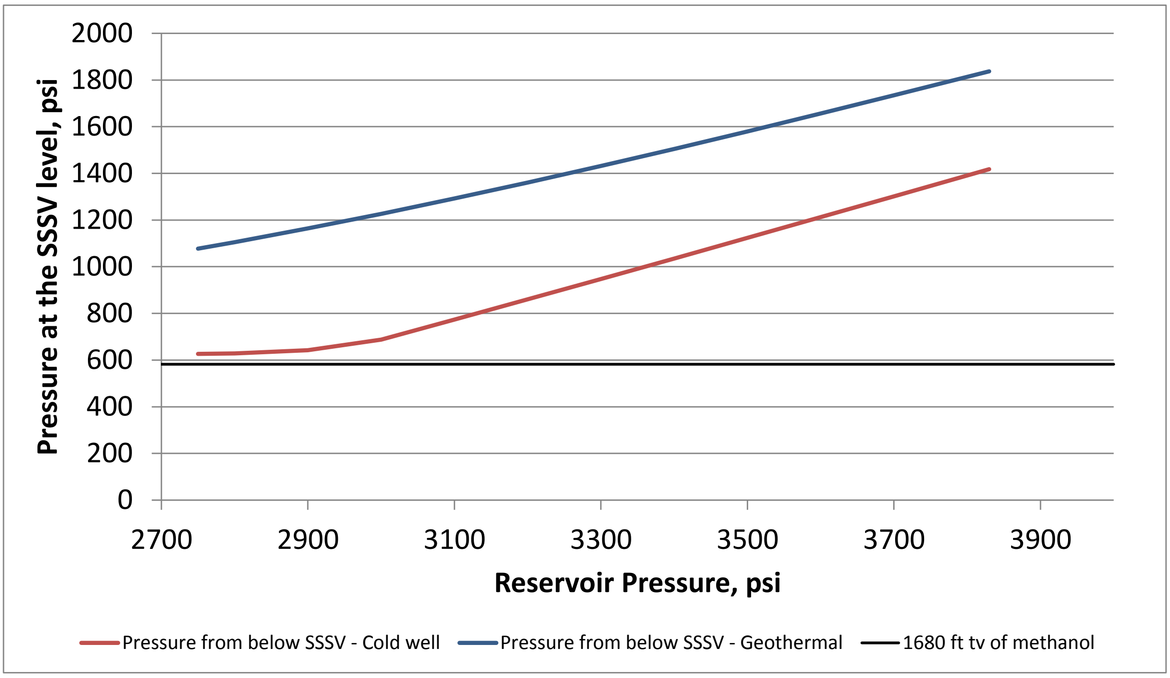


Figure 8-9: Pressures at the SSSV in case of displacing a full column of methanol between the tree and the valve after a normal testing of the SSSV

If injection needs to re-commence it is required to equalise the pressure across the valve. The pressures at the valve after pumping 1680 ft of methanol, Figure 8-8, indicate that for all cases the valve is closed. The option to equalise the pressures at the valve using methanol or using CO_2 will need to be assessed at that particular time; the following are the elements to consider:

- Section 7.5.1 indicated a worst case scenario in terms of JT cooling when the well is bled-off above the SSSV to atmospheric conditions and equalising pressures with CO_2. The generated transient temperatures are compatible with the well design
- JT cooling at the tubing head after valve equalisation. This will depend mainly on the tubing head pressure after equalisation.

Different scenarios can be encountered:

I. For high reservoir pressures (>3100 psia) and geothermal condition. Equalise using methanol in the well.
Continue displacing methanol into the well until pressures of the valve are equalised. Required tubing head pressure of 35 bara for 3100 psia reservoir pressure and 68 bara for 3830 psia reservoir pressure.

II. For high reservoir pressure (>3700 psia) and cold conditions. Equalise using methanol. Tubing head pressure after equalisation higher than 31 bara.

III. For low reservoir pressures (<3100 psia) and geothermal conditions the options are to equalise with CO_2 or methanol.
Equalising the pressures using CO_2 would be similar to the section 7.5.1 in this report. Short transient temperatures will be observed in the top of the well which seems to be compatible with the well design.
Equalising with methanol can be done by injecting more methanol into the well and applying a pressure of 15 bara at 2750 psia reservoir pressure and 30 bara at 3100 psia. Once the

pressures are equalised and control line is applied then the he CO_2 can be introduced into the well. Some JT cooling expected in the top of the well according to the tubing head pressure.

IV. For reservoir pressures between 3200 psia and 3700 psia and cold conditions. Similar to case III

V. For reservoir pressure below 3200 psia and cold well.
This case is important in the sense that a full column of methanol between the tree and the SSSV will open the valve and the pressure at the tubing head will be close to atmospheric conditions. It might be required to have a N_2 cushion in the top of the well to avoid the JT expansion as per the initial injection of CO_2 in the well.
However, from the calculations in section 7.5.1 it would be possible to re-start injection using the CO_2 as the transient effects seem to be compatible with the well limitations.

From the conditions above, each case is different and needs to be evaluated in a case by case basis. The final injection re-commencing procedure might include the injection of a N_2 cushion into the tubing to increase the tubing head pressure before the CO_2 injection to avoid excessive transient cooling in the top of the well or waiting for the well to warm up to geothermal conditions. CO_2 injection with the SSSV closed seems also a viable solution.

This is not a planned situation; the most important part is to displace at least 4 m^3 of methanol into the well immediately after this well condition is identified. How to recommence CO_2 injection in the well will thereafter depend on the well status/conditions at the time.

8.3.8. Initial Start-up of Injection

Guideline *Follow guideline section 5.6*

To prevent any issues, it is advised to replace the content of the tubing by injecting methanol (at least 6 m^3 of methanol for the well configuration) before starting to inject CO_2 into the reservoir.

Furthermore, a N_2 cushion is required to avoid JT expansion in the top of the well when due to the low reservoir pressure. The required columns of the different fluid are presented in section 6.6.

8.3.9. Starting-Up after a Well Intervention (Water Displaced Into the Well)

Guideline *Inject 6 m^3 of methanol into the well*

Assess individual cases to re-commence injection considering mainly the reservoir pressure

High reservoir pressure will require the injection of only methanol into the well

Low reservoir pressures are similar to the initial start-up. A N_2 cushion is recommended.

An increased hydrate risk exists when water is present in the well tubing after a well intervention. If this water becomes in direct contact with CO_2 at temperatures below 15°C, a hydrate formation risk exists.

Therefore, it is essential that the content of the tubing is inhibited (methanol/water) after an intervention. If the well tubing contains brine or inhibited water, it may lead to issues when cold CO_2 is injected on top of the water column.

The most controlled way of preventing issues during start-up is by replacing a part of the content of the well tubing by the hydrate inhibitor (methanol). After injecting 6 m^3 of methanol the well content up to the SSSV will be replaced by methanol. Because of the density differences between methanol and (inhibited) water/brine, the methanol will stay on top of the column. For a normal start-up, this amount of methanol will be sufficient to control hydrates.

The other consideration is related to the JT cooling when the CO_2 is introduced and depends on reservoir pressure.

For high reservoir pressures the introduction of methanol into the well will be enough to obtain a high tubing head pressure and avoid the JT cooling during the CO_2 re-introduction into the well. For example assuming a reservoir pressure of 3500 psia and a methanol column of 7000 ft then the tubing head pressure will be in the order of 30 bara with water below the methanol column to the bottom of the well.

However, for low reservoir pressures, this case will be similar to the initial injection of CO_2 into the well where a N_2 cushion is recommended, section 6.6.

8.4. Remediation in Case of a Hydrate Plug

Symptoms may indicate that a hydrate plug is being formed. An example of such an indication can be the erratic behaviour of the wellhead pressure or pressure drop over the wellhead choke (flow fluctuations) during CO_2 injection. In case of a blockage, the pressure will show an increase in the pressure in the pipeline when injecting. During a depressurisation, this erratic behaviour may be observed in the form of pressure drop fluctuations over the vent valve.

During depressurisation operations a blockage in the vent line would result in a pressure increase in the piping upstream of the blockage and may lead to a large pressure drop over the hydrate plug. Immediate action is required to prevent events going from bad to worse by closing the section that contains the blockage. In general, when hydrates are likely to be formed and symptoms indicate a hydrate plug, the best way forward is to immediately stop the CO_2 injection or stop the depressurisation and assess the situation.

During the assessment, one should try to determine the location of the blockage, as the location of the plug may limit the remediation options. Common method to determine the location of a blockage is to do a partial depressurisation. From the initial and final pressures and a measurement of the released amount of gas the location of the blockage can be estimated.

As the CO_2 stream contains a very small amount of water, hydrates might be formed at a very low temperature, a period of shut-in may already melt the blockage. If not, two-sided depressurisation is generally recommended for conduits that are completely blocked, as it is safer because there is less (not zero) risk that large pressure differences will be created over a hydrate plug. This would also be the recommended remediation for the topside pipework on the Goldeneye platform. Although in principle straightforward, care must be taken that depressurisation does not worsen the problem or threaten the integrity of the system. The following general guidelines apply to depressurisation:

1. The approximate hydrate dissociation pressure must be known before starting the depressurisation, such that the operator knows the conditions when hydrates start to melt.
2. The system is depressurised in steps of not more than a few bar each.
3. It must be possible to immediately close-in the system if pressure surges are observed.

A two-sided depressurisation is not possible for a blockage in the well tubing. Given the fact that hydrates can only be obtained at very low temperatures (-23°C) for normal operational conditions, a shut-in period would already melt the plug as heat will be transferred from the environment to the blockage. Care should be taken that the pressure stays within the limits of the system. If necessary, the pressure should be released from the well head tubing.

If the blockage occurs as part of an operational upset, e.g. more water may have entered the well tubing, the remediation actions may become a time consuming process. If the hydrate plug does not melt after a period of shut-in, which may occur for depths ranging between 200-1200 m below the seabed (depending on the soil/rock temperature around the well tubing and the water content of the fluid), an alternative method may be required. Injecting a batch of methanol may not affect the hydrate melting process as the density of methanol is well below the density of the dense CO_2 fluid and, therefore, the methanol may not reach the hydrate blockage or, when in contact with the blockage, melting of the plug would cause a layer of water on top of the plug that separates the methanol from the plug. In these cases, injection of a MEG solution into the well tubing (with a temporary injection skid) would provide a better solution. Based on the density, the MEG solution would become in contact with the plug and the process of melting would take place.

Without MEG injection, one may require a stepwise depressurisation, which involves much more operational risks. Pressure drop may have been build-up over the plug and a sudden release of the plug may cause a pressure surge through the system and the hydrate plug may hit the topside valve and causing damage. If this approach is done, care should be taken analyse the possible impact of a sudden pressure release, the control options (pressure/flow sensors and control valve) required to counteract the surge and the safety risks involved for the topside equipment.

9. Conclusion

Simulations have been used to generate operating guidelines for the CO_2 injection wells which will prevent minimum design temperatures of the well components being exceeded.

The operation procedures in the CO_2 injector wells need to be followed strictly due to the potential cooling in the top of the well. These guidelines will serve as the basis to develop well operation procedures in the detail design of the project.

10. References

1. **PCCS-05-PT-ZW-7180-00003.** *Well Completion Select Report (Key Knowledge Deliverable 11.097).* s.l. : Shell Peterhead CCS, 2014.

2. **PCCS-05-PT-ZW-7770-00001.** *Well Technical Specification (Key Knowledge Deliverable 11.099).* s.l. : Shell Peterhead CCS, 2014.

3. **PCCS-05-PT-ZP-9025-00004.** *Geomechanics Summary Report (Key Knowledge Deliverable 11.115).* s.l. : Shell Peterhead CCS, 2014.

11. Glossary of Terms

Term	Definition
13Cr	13 percent chrome content metallurgy
A-annulus	Annular space between the production casing and tubing
AHD	Along Hole Depth
API	American Petroleum Institute
B-annulus	Annular space between the surface casing and the production casing
Base Oil	Oil with carcinogenic elements removed
Bean Up/Down	A choke sequence used to control flow
BHIP	Bottom Hole Injection Pressure
BHIT	Bottom Hole Injection Temperature
BO	Base Oil
	Oil with carcinogenic elements removed
C	Cement
C-annulus	Annular space between the conductor and the surface casing
Cap Rock	The shale layers above a reservoir that provide geological isolation to upward migration and provide the primary seal
CCS	Carbon, Capture and Storage
CFD	Computational Fluid Dynamics
CITHP	Closed-in Tubing Head Pressure
CITHT	Closed-in Tubing Head Temperature
CO_2	Carbon Dioxide
DTS	Distributed Temperature Sensors
FTHP	Flowing Tubing Head Pressure
HET	Hydrate Equilibrium Temperature
Hol	Hold-Up. Proportion of gas-liquid in the tubing
Hor L	Horizontal Length
ID	Internal Diameter
JT	Joule Thomson effect
LMGV	Lower Master Gate Valve
MD	Measured Depth
mD	milli-Darcy, unit of permeability
MEG	Mono Ethylene Glycol
MMscfd	Million Standard Cubit Feet per day
N_2	Nitrogen
OBM	Oil-based Mud
OLGA	A commercial multiphase flow modelling software from Schlumberger
P-H flashing	Specific Pressure-enthalpy flashing in OLGA
PCV	Pressure Control Valve
PID	Proportional-Integral-Derivative controller
$P_{reservoir}$	Reservoir Pressure
s13Cr	Super 13 percent chrome content metallurgy

SSSV	Subsurface Safety Valve
SW	Seawater
TH	Tubing Head - The top part of the well
THP	Tubing Head Pressure
THT	Tubing Head Temperature
TVD	True Vertical Depth
UMGV	Upper Master Gate Valve
WH	Wellhead - the top part of the well
WHP	Wellhead Pressure
WHT	Well Head Temperature
WV	Wing Valve

12. Glossary of Unit Conversions

Table 12-1: 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 12-2: Well Name Abbreviation Table

Full well name	Abbreviated well name
DTI 14/29a-A3	GYA-01
DTI 14/29a-A4Z	GYA-02S1
DTI 14/29a-A4	GYA-02
DTI 14/29a-A5	GYA-03
DTI 14/29a-A1	GYA-04
DTI 14/29a-A2	GYA-05