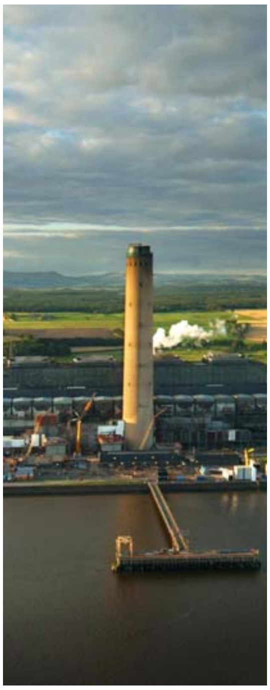

UK Carbon Capture and Storage Demonstration Competition

UKCCS - KT - S7.18 - Shell - 002

Injectivity Analysis Preparation

April 2011

ScottishPower CCS Consortium

SCOTTISHPOWER nationalgrid

Carbon Capture & Storage Consortium

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ScottishPower Consortium UKCCS Demonstration Competition: Knowledge Transfer

KEYWORDS

Goldeneye, CO_2, .

Produced by Shell U.K. Limited

ECCN: EAR 99 Deminimus

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1. Introduction

1.1. Objective

The objective of this document is to analyse the expected injectivity of CO_2 in the GoldenEye reservoir. The maximum CO_2 injection rate in the reservoir will be in line with the capacity of the capture plant, which is estimated to be 2.2 million tonnes per year (114.4MMscf/day).

Preliminary calculations indicate that the initial phase of CO_2 injection at low reservoir pressure will be under matrix injection conditions. However the late phase of injection, when the reservoir pressure increases, is uncertain in terms of injection condition:- that is whether later injection will be matrix injection or fracturing conditions.

This report assumes CO_2 injection under matrix condition. Injection Fraccing conditions will be documented in the injection fraccing condition report[1].

This report is divided into three main sections: Initial injectivity, impairment and mitigation options.

The first section analyses the expected initial injectivity in Goldeneye. Consideration is given to the rock properties in the main reservoir, hydrocarbon productivity and the conversion from hydrocarbon production to CO_2 injectivity. Differences in PVT and relative permeability are assessed.

The second section is related to the deterioration of injectivity with time or impairment. Different factors have been analysed considering the lower completion type in Goldeneye wells. It is assumed that there will be no sidetrack. Analysed factors include purely mechanical / physical and chemical barriers.

The third section in the report summarises injectivity management under CO_2 operation and includes the mitigation options.

Finally, Appendix A documents the thinking behind the cancellation of the initially planned injectivity test.

1.2. Executive Summary

The initial CO_2 injectivity in Goldeneye is expected to be good. Injection pressure is well above the reservoir pressure for the expected injection rates (200 to 400psi greater). This conclusion is based on the rock properties and the hydrocarbon productivity. Corrections are made to the hydrocarbon productivity to obtain the expected CO_2 injectivity.

The risk of not being able to inject the desired amount of CO_2 can be reduced by some proactive measures such as pipeline commissioning, filtration of the CO_2 stream and hydrate inhibition.

- Displacement of any pipeline content into the wells during the pipeline-commissioning phase must be avoided. This is to avoid the risk that pipeline debris could potentially be injected into the wells, causing damage or impairing downhole sand control.
- For the same reasons, during the life of the project CO_2 filtration is required to avoid blockage in the formation and blockage in the lower completion.
- Hydrate inhibition is required for a period of time until the water / hydrocarbon is displaced away from the wellbore.

[1] Injection Fraccing conditions KT 7.18

There are other potential impairment mechanisms, which are considered of very low risk to CO_2 injectivity. These include Joule Thomson cooling, Halite precipitation, and organic deposits such as wax and asphaltenes.

Flow reversal is the only mechanism without any mitigation option. However, based on production information the risk is low. Apart from the proactive measures that can be taken, in the event of injectivity reducing with time there will be some reactive operations which might be carried out to re-gain injectivity performance(in a similar manner to any hydrocarbon development project).

The number of wells converted to CO_2 injection can mitigate the risk of insufficient injectivity due to well impairment or well failure. By using more injector wells, the risk is spread and hence reduced.

2. Injection Requirements

The Completion Requirements report[2] specifies the completion requirements for the Goldeneye injection wells.

The wells available for injection should be able to manage injection from the minimum CO_2 delivery rate to the capacity of the CO_2 capture plant. In summary, Goldeneye wells can be managed to accommodate different injection rates.

The minimum delivery rate of the carbon capture plant is estimated at 34 million scf/day. The maximum capacity of the capture plant is currently estimated to be 114million scf/day.

The Temperature and Pressure Modelling[3] report highlights the limited operating envelope of the wells due to the management of the CO_2 in single phase. The wells will be operated between 45 to 115 bar using friction created by the tapered small tubing.

By using multiple wells, several different completion sizes should be designed such that they can handle the fluctuating injection rates arriving at the platform.

In order to accommodate the wide range in injection rates, tubing size optimization (in the case of CO_2 management by friction)is essential. Different tubing sizes (from 3½" to 4") and different length combinations are anticipated.

Five wells are available for injection in the Goldeneye platform. Current calculations indicate that the injection per well will have a limited window of operation of 10-20 million scf/day. As such, multiple wells will be required to cover the injection range from the minimum to the capacity of the capture plant.

A particular well will have its own operating envelope depending mainly on its tubing size, which will be dictated by the reservoir requirements. The calculation of the number of wells is documented in the Operations Support report[4] and the Completion Concept Select report[5].

For this report the injection rate range per well is estimated between 20 million scf/day to 60 million scf/day.

The reservoir pressure just before CO_2 injection is estimated to be 2850psi and at the end of injection is estimated at 3600psi.

[2] Completion Requirements report.

[3] Temperature and Pressure Modelling report

[4] Operations Support report

[5] Completion Concept Select report

3. Initial Injectivity

The expected initial CO_2 injectivity is excellent based on the reservoir characteristics of the main Captain D reservoir in Goldeneye (section 3.1). The best information available to estimate the future CO_2 injectivity is the current hydrocarbon wells productivity. The hydrocarbon productivity has been excellent and has confirmed the reservoir characteristics (section 3.2).

The CO_2 injectivity under matrix conditions can be estimated from the hydrocarbon productivity considering the different PVT between the hydrocarbon and the CO_2 PVTs (section 3.3). The impact of the PVT correction is small in the injectivity as the high viscosity of the CO_2 is compensated by the low expansion factor of the CO_2 with respect to the hydrocarbon gas. The differences in relative permeability between the hydrocarbon gas and the CO_2 (section 3.4) should also result in a small impact.

In conclusion, the initial injectivity is expected to be similar to the hydrocarbon productivity (applying the different corrections) and it is considered excellent for the CCS project.

3.1. Reservoir Characteristics

The main factor dictating productivity and injectivity is the quality of the formation.

The Goldeneye reservoir is the Captain sandstone (lower Cretaceous) which is mainly a turbidite deposit with an excellent reservoir quality (Figure 3-1).

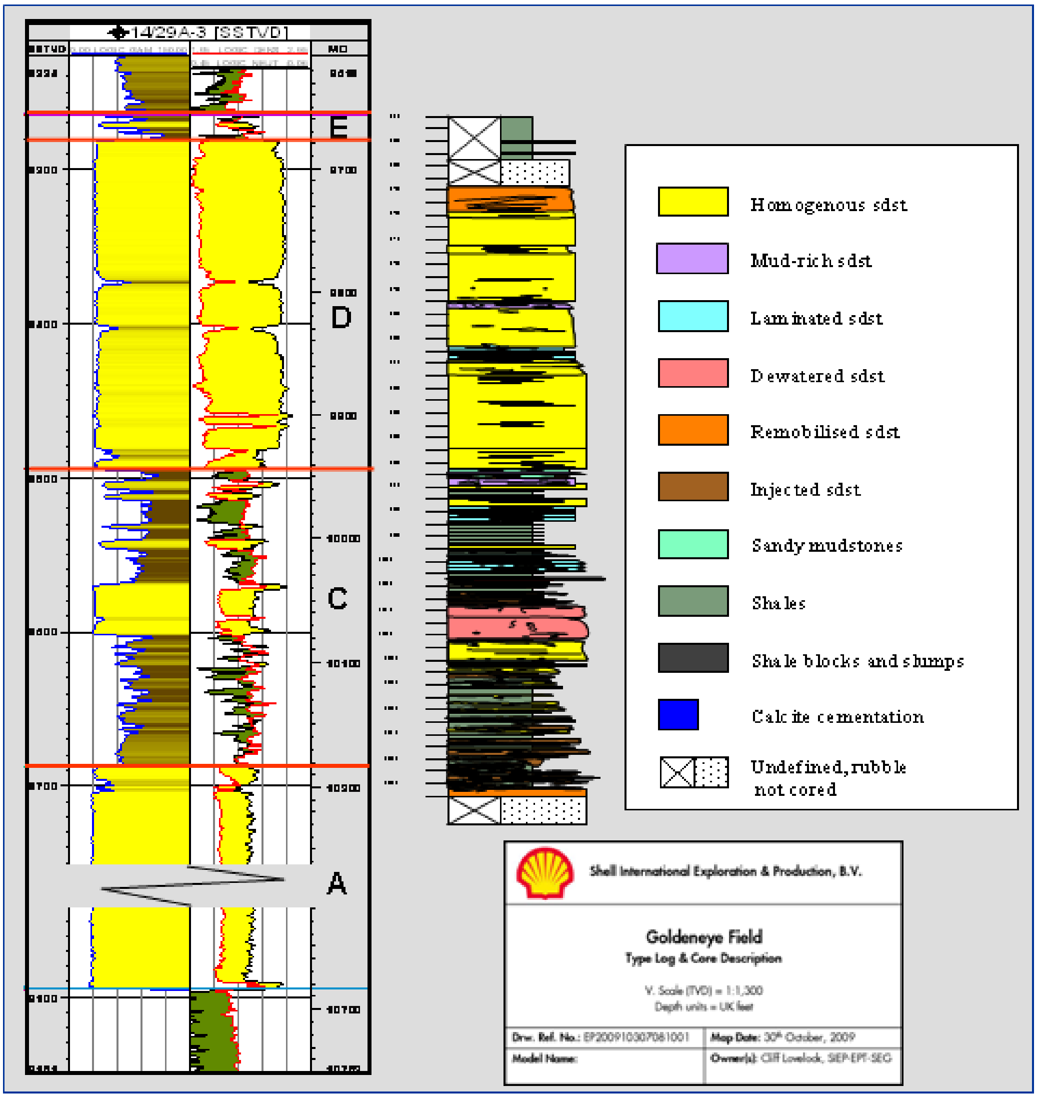

Figure 3-1: Subdivision of the Captain reservoir, Goldeneye area. Log data on left with core facies log description on right. Note unit A is homogenous in parts and highly variable in thickness (shown partial log).

The Captain 'D' is the primary reservoir unit, into which all the development wells have been completed. The 'D' unit has been cored in all of the exploration and appraisal wells in the Goldeneye Field. It comprises medium grained massive sandstones that, with few exceptions, show only subtle changes in grain size.

Average porosity of Captain 'D' reservoir is about 25% and average permeability is around 790mD. The average Net to gross is about 94%.

The thickness of the Captain D varies from 75 to 225ft (TVD) with an average of 130ft. These are the primary indications that we can expect good injectivity in the captain reservoir in the Goldeneye field.

All the available wells were completed in the top of the Captain D formation (60ftTVD). The 9-5/8" casing was set in the Rodby formation. The Captain D and E are open to the gravel pack and screens. The Captain E characteristics are poor with average Net to gross of about 61%, average net porosity of around 21% and average permeability of only around 7%. Clearly the contribution of Captain E in comparison with Captain D is negligible.

The formation is well connected based on production and pressure information collected during the hydrocarbon production.

3.2. Hydrocarbon productivity

The hydrocarbon productivity has been good with high production rates at relatively low drawdown. The gas production rate during the initial clean-up (after completion) was between 90 to 105million scf/day per well. Figure 3-2 shows the behaviour of the wells during the clean-up.

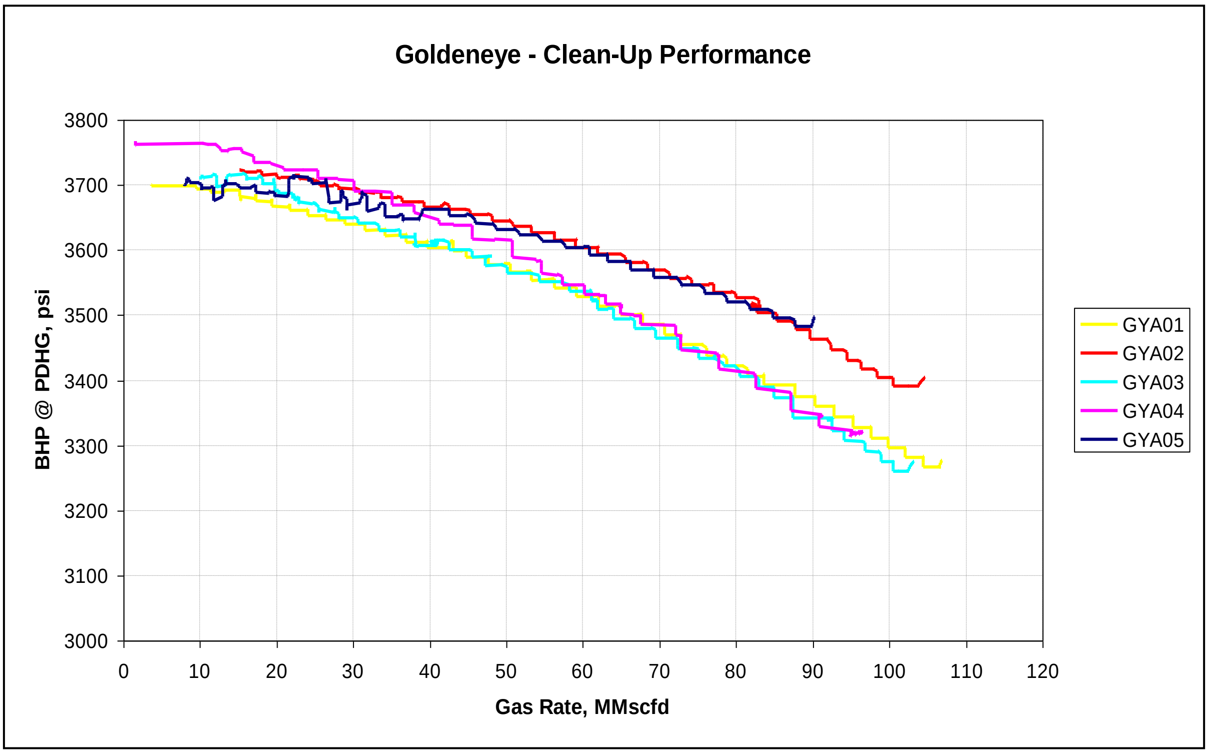

Figure 3-2 Productivity during well clean-up operations

The high productivity has been maintained during the production life of the wells. In general, low drawdown levels have been required (200psi drawdown for 60 million scf/day of production).

The well productivity has been stable during the production time, demonstrating no impairment with time. This can be observed in Figure 3-3 (note that the other wells have similar performance).

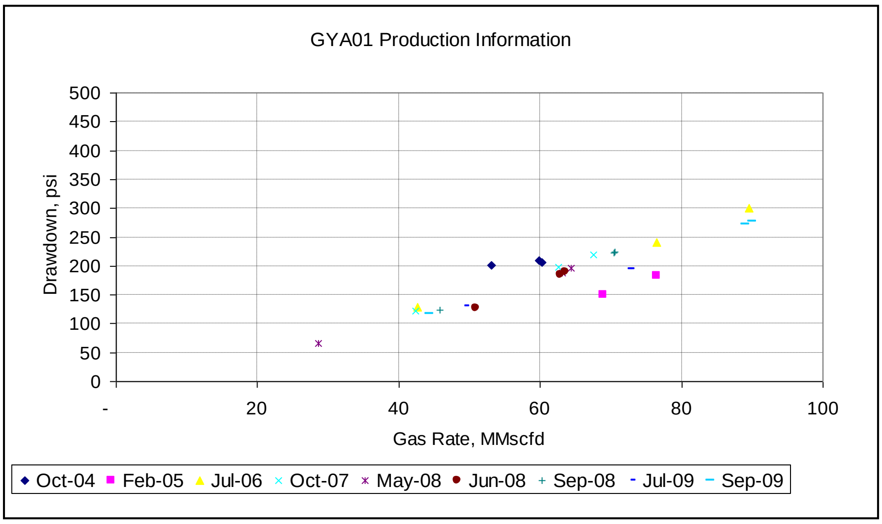

Figure 3-3 GYA01. Productivity history

The productivity of the wells has been good as expected from the high permeability.

There are minor differences between the wells (Figure 3-4). . GYA02S1 and GYA05 are slightly stronger than the rest of the wells (in line with the initial clean-up of the wells).

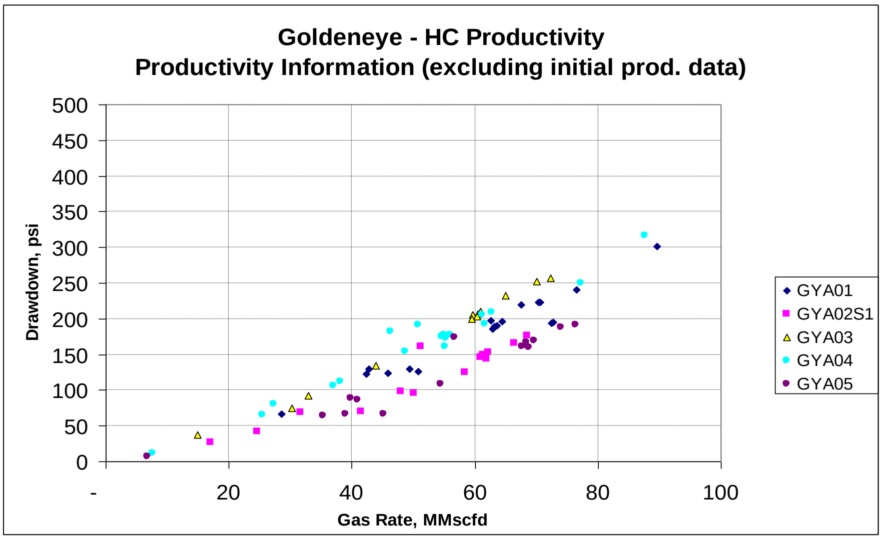

Figure 3-4 Productivity per well during long term production phase

Inflow Performance from gas wells can be represented mathematically using the Jones equation, as follows:

$P_{reservoir}^2 - P_{wf}^2$ = Darcy coefficient * Q + Non-Darcy coefficient * Q^2

Based on the well performance the wells can be grouped in two sets:

- GYA01, GYA03 and GYA04
- GYA02S1 and GYA05

The calculated coefficients considering the production information are as follows

GYA01, GYA03 and GYA04

- Darcy coefficient: 0.0017bar^2/(sm^3/d)
- Non-Darcy coefficient: 4 E-10bar^2/(sm^3/d)^2

GYA02S1, GYA05

- Darcy coefficient: 0.001bar^2/(sm^3/d)
- Non-Darcy coefficient: 4 E-10bar^2/(sm^3/d)^2

And graphically presented in the Figure 3-5.:

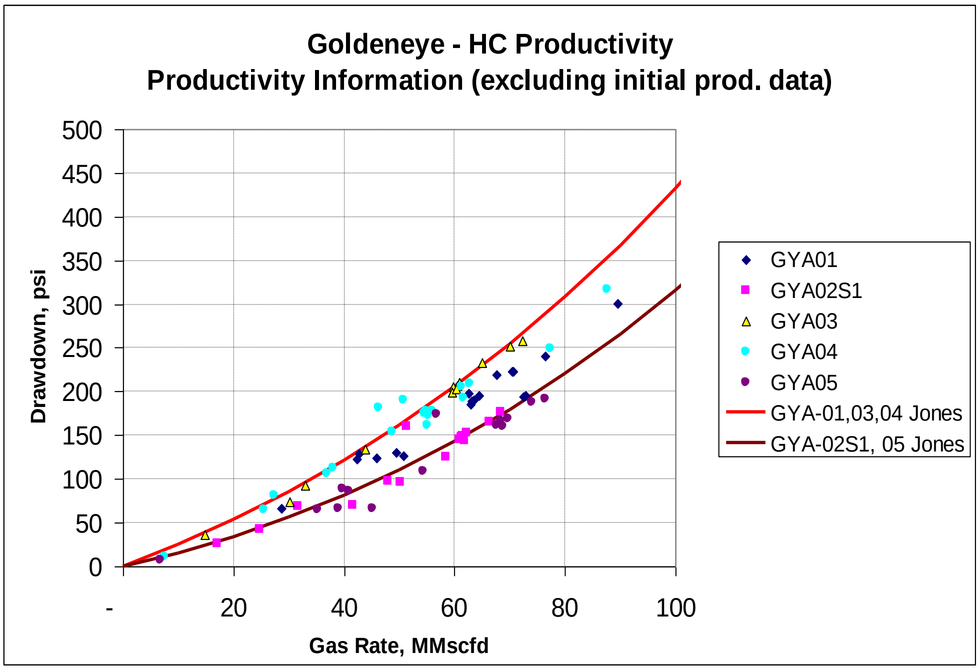

Figure 3-5 Productivity. Jones representation.

3.3. Correction of hydrocarbon productivity for CO_2 injection due to PVT changes

This section relates to the correction of hydrocarbon productivity to obtain CO_2 injectivity based on the difference in the flowing properties of hydrocarbon and CO_2. Relative permeability is not included in this section.

The CO_2 injectivity will be different to the current hydrocarbon productivity due to differences in the PVT properties between the hydrocarbon gas currently produced and the CO_2 injection. The magnitude is relatively small, for example for 60 million scf/day flow, the drawdown for hydrocarbon gas production is between 150 to 200psi, whilst for CO_2 the injection would be between 280 and 380psi above the reservoir pressure.

The current reservoir pressure is in the order of 2,100psi (145bar). At the planned injection year the reservoir pressure should be higher due to the aquifer effect. The reservoir pressure just before CO_2

injection is estimated to be around 2850psi. The reservoir temperature is ~83°C whilst the injection temperature at reservoir level will be between 20 to 35°C[6] .

The required bottom hole pressure is higher than the critical pressure of the CO_2. At reservoir temperature, the CO_2 will be supercritical whilst at the injection temperature the CO_2 can be considered as liquid or supercritical fluid depending on the injection temperature. The viscosity of the CO_2 will be higher than the viscosity of the hydrocarbon gas.

The downhole in situ rate of the CO_2 has a high dependency on the pressure and temperature. The downhole rate of the CO_2 for a given surface rate is much smaller than the hydrocarbon production. Both effects are illustrated considering in the following figures (Figure 3-6 and Figure 3-7):

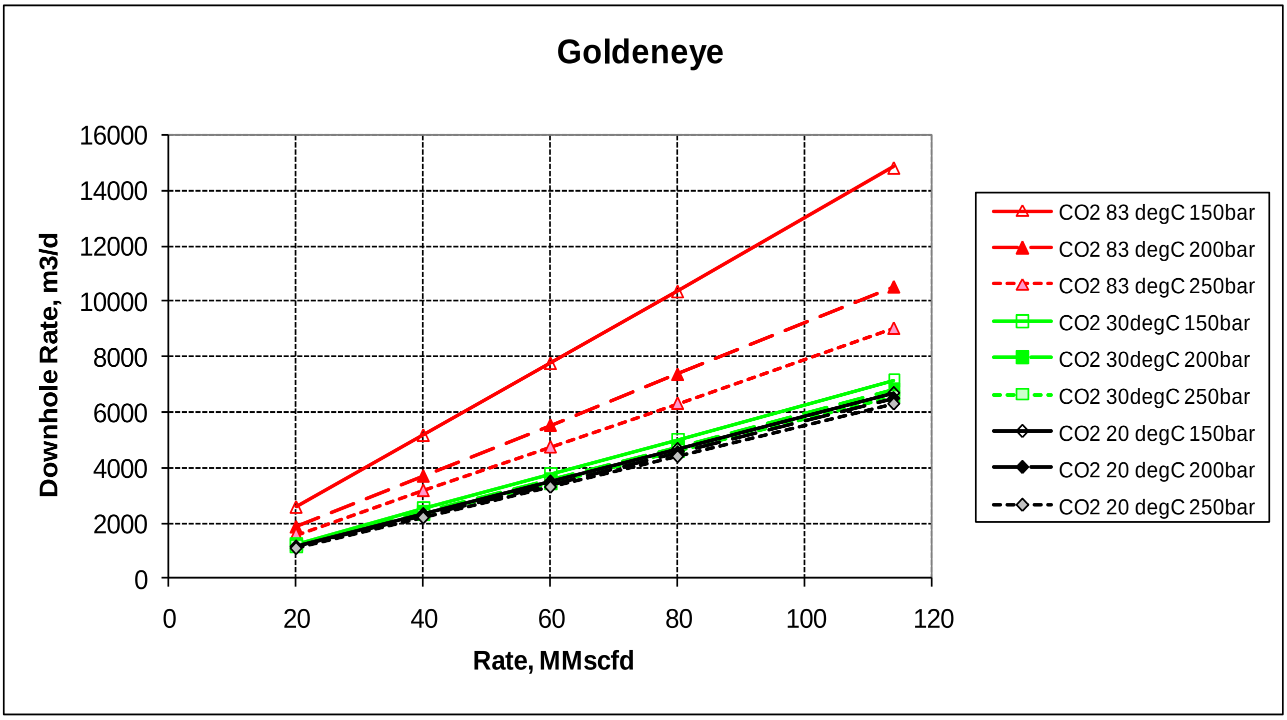

Figure 3-6 CO_2 downhole (in-situ) injection rate for given surface rate

[6] Temperature and Pressure modelling report.

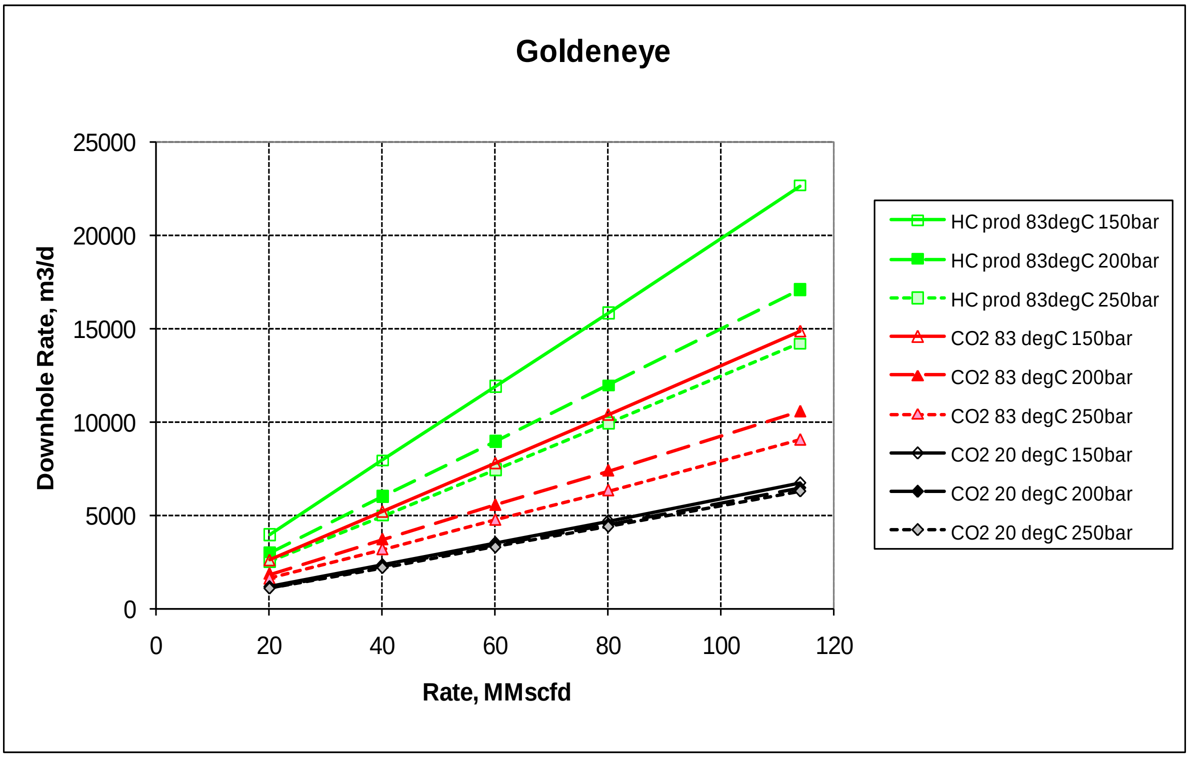

Figure 3-7 Comparison of CO_2 and hydrocarbon downhole rates

The viscosity of the CO_2 is higher than the viscosity of the hydrocarbon gas in Goldeneye (see Figure3-8). This difference in properties will have a negative effect on the injectivity.

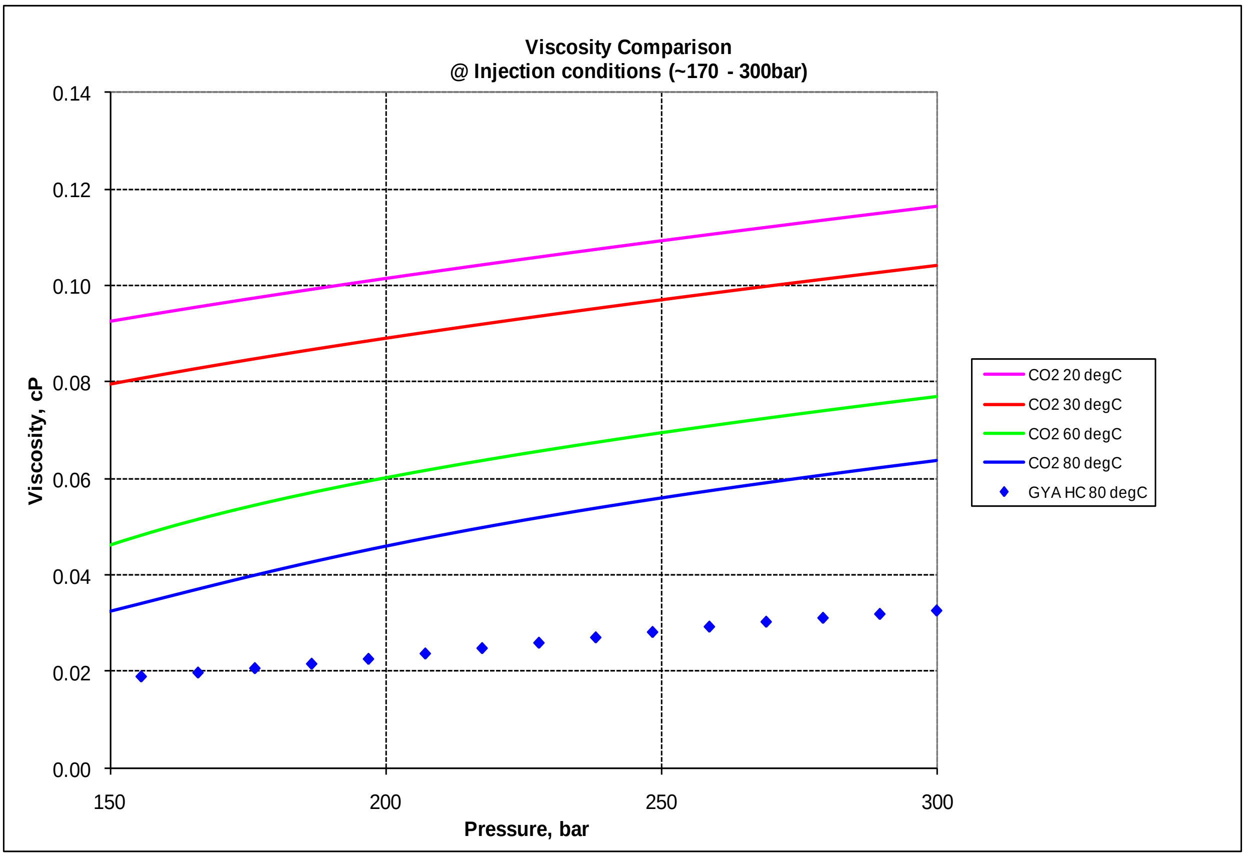

Figure 3-8 Comparison of Viscosity between CO_2 and hydrocarbon gas.

The difference between CO_2 and hydrocarbon gas in terms of equivalent downhole rate and viscosity can be calculated with the previously calculated Jones equation as follows:

$$P_r^2 - P_{wf}^2 = Aq + Fq^2$$

$$A_{CO2} = A_{gas} \frac{\mu_{CO2}}{\mu_{gas}} \frac{Z_{CO2}}{Z_{gas}} \frac{T_{CO2}}{T_{gas}} = A_{gas} K_A$$

$$F_{CO2} = F_{gas} \frac{Z_{CO2}}{Z_{gas}} \frac{\gamma_{CO2}}{\gamma_{gas}} \frac{T_{CO2}}{T_{gas}} = F_{gas} K_F$$

A is the Darcy coefficient and F is the Non Darcy coefficient.

The main assumptions to the equation are:

- Same permeability, skin and drainage radius for CO_2 and gas
- No complex reservoir effects (e.g. well interference, external behaviour, etc)
- Relative permeability effects not included
- CO_2-rock chemical reaction not included
- Matrix injection

Because of the variable properties of the CO_2 (Z factor, viscosity and density) with pressure and temperature, the injectivity will vary with these factors. However, the effect is relatively small as can be observed in the following figures (Figure 3-9 and Figure 3-10) where the CO_2 injectivity is shown at different pressures and temperatures.

The required pressure above the reservoir pressure in order to inject 20 million scf/d of CO_2 is around 60 to 100psi depending on well. For the maximum considered rate of 60million scf/d then the delta pressure is around 280 to 380psi.

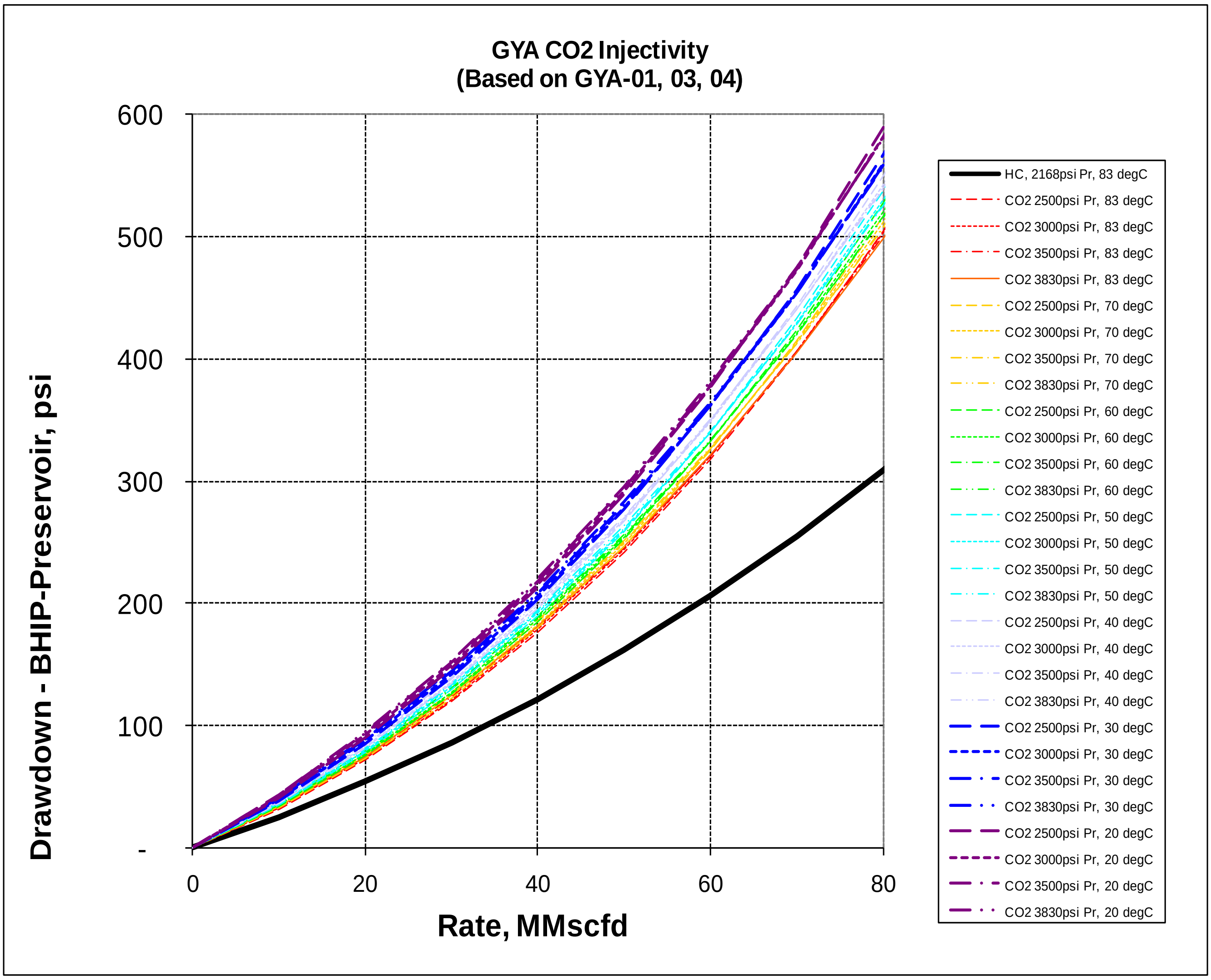

Figure 3-9 CO_2 injectivity vs hydrocarbon productivity (GYA01, GYA03 and GYA04)

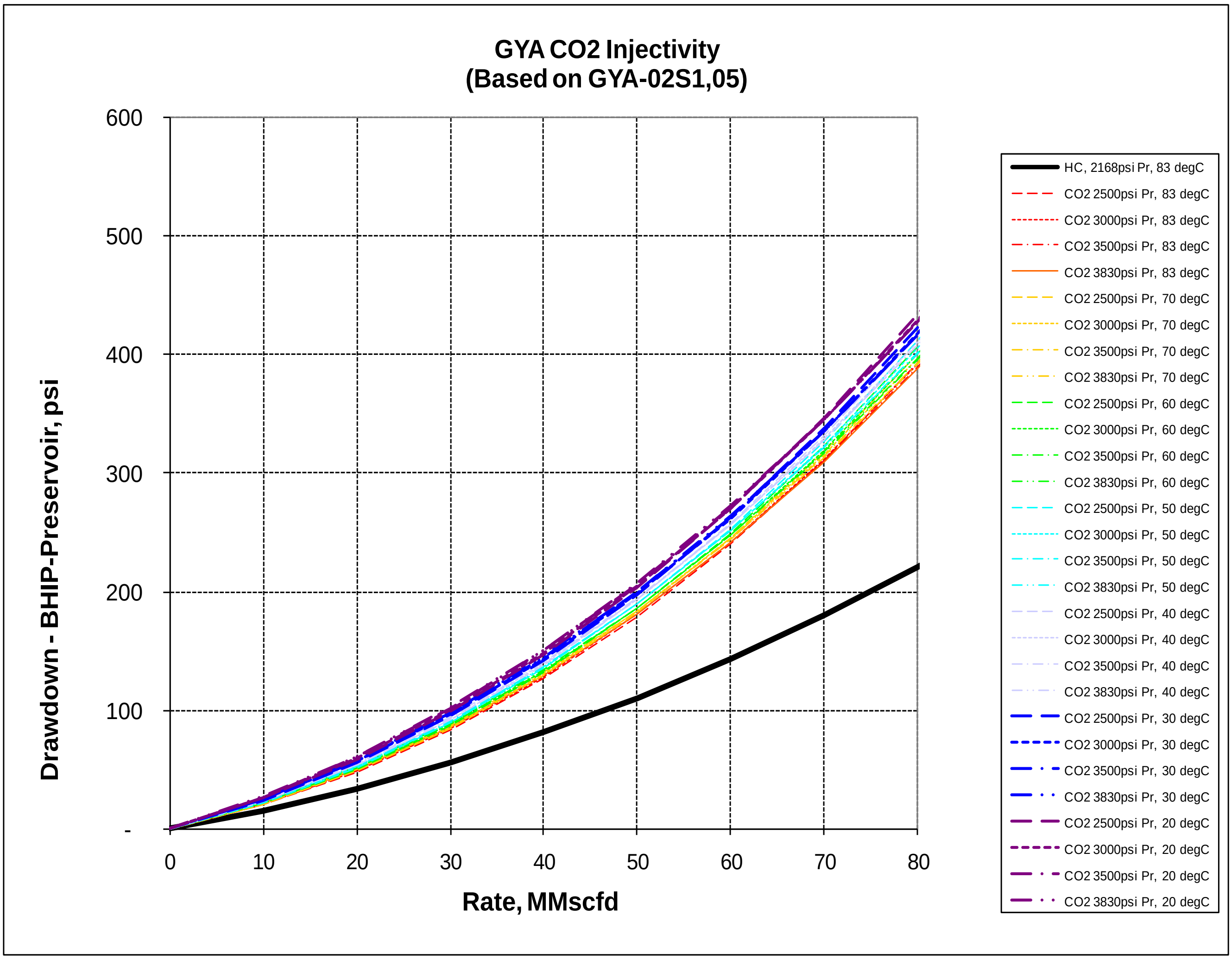

Figure 3-10 CO_2 injectivity vs hydrocarbon productivity (GYA02S1 and GYA05)

The injectivity values in this section will be used for the selection of the different tubing sizes.

3.4. Relative Permeability

In order to understand the CO_2 injection in Goldeneye it is important to take into account the displacement processes that might occur within the reservoir from the early gas / condensate production, up to the point where injection occurs. This will determine the fluid distribution in the vicinity of the well and therefore, the relative permeability effects which impact injectivity

Special Core Analysis (SCAL) data currently available in the field gives a range of S_{gr} of 25% - 38% at maximum gas saturation. Also, the literature review shows a strong correlation between porosity and residual gas saturation. Porosity of ~ 25% measured in Goldeneye, can be related to the residual gas saturation of ~ 30%. Simulation models built to assess the CO_2 injection (simple box model in addition to a full field model) were conditioned or history-matched with S_{gr} in the range of 25% to 30%.

The CO_2 injection in Goldeneye will be a gravity-dominated process, where the microscopic displacement efficiency is quite high, even though in the near wellbore area there will still be a viscous displacement. Nevertheless, the density difference of the fluids in addition to high rock quality in Captain sands, will generate a strong segregation and the displacement process will be gravity dominated. This will reduce water saturation to small values, where the relative permeability should be very low for water and high for the CO_2. So we can expect the CO_2 to have a favourable mobility ratio and, as a consequence, good injectivity.

Nevertheless, in order to inject CO_2, brine must be pushed away from the injector to create the space for CO_2 to enter. The ease with which the CO_2 can displace the brine will depend on the mobility ratio between CO_2 and brine, which is defined in terms of the effective permeability and viscosity of the displacing fluid (supercritical CO_2) and displaced fluid (brine). Fluid viscosity can be assumed as constant, even though there will be a cooling and dry out effect in the wellbore neighbourhood, but there is uncertainty in the water relative permeability end point and shape (Corey exponent) that might have an impact on injectivity.

As a consequence, a simulation model was constructed to investigate these effects. A simple box model that broadly represents a quarter of Goldeneye in volume with similar rock properties (permeability and porosity) and dip angle was used to simulate these effects. The model was conditioned with a 10 years depletion period, further 10 years of recharge from the aquifer and finally, a 10 years CO_2 injection.

Various sensitivities were performed to assess the impact of water relative permeability, whilst gas relative permeability and all other parameters were held constant. Water relative permeability end point values, based on data where saturation does not require correction, supports a range of 0.05 to 0.25.

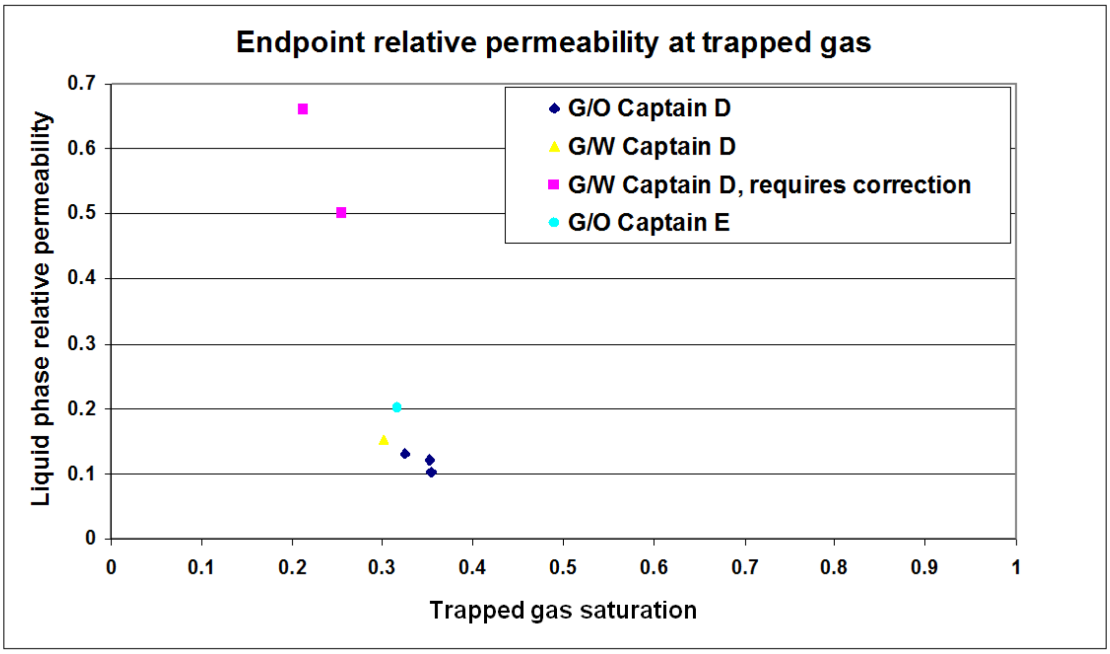

Figure 3-11. Endpoint relative permeability at trapped gas saturation

Sensitivity analysis was carried out on a range of values of effective water relative permeability at residual gas saturation (S_{gr} = 30%) within the observed data available, varying from 0.1, 0.25 and 0.6. Results from the model showed little impact on the bottom hole pressure of the injector due to variations in k_{rw}. This is true in the case where the wells are completed in the top of the reservoir (as they currently are) and in the crest of the structure (GYA01 and GYA02S1), where the remaining hydrocarbon column will cover the gravel pack. This means that mainly connate water saturation will be surrounding the wellbore and CO_2 will be injected into a hydrocarbon gas column, making it easy and less likely to be sensitive to relative permeability effects.

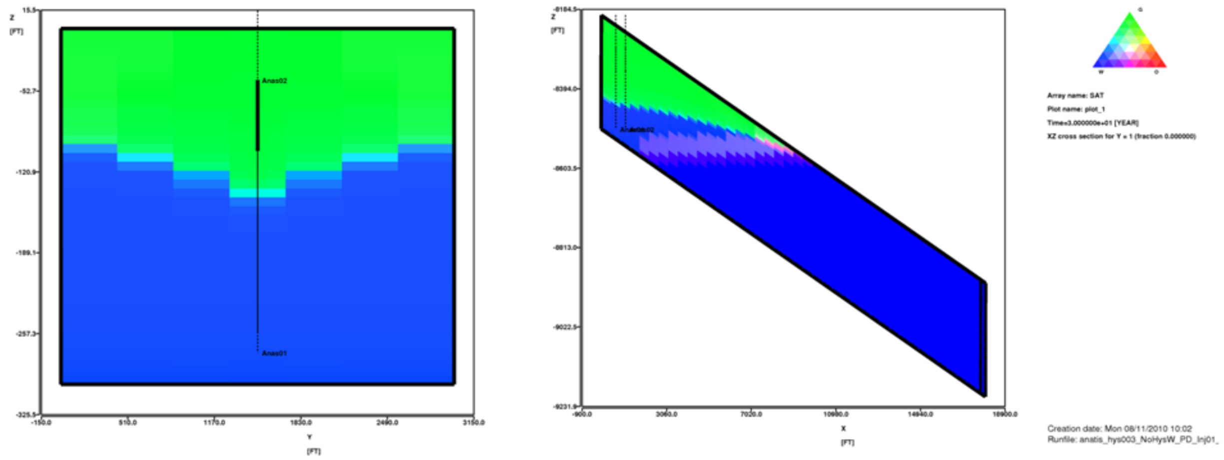

Figure 3-12. Cross section of simple box model. Ternary saturation diagram. Injector located at the top of the structure.

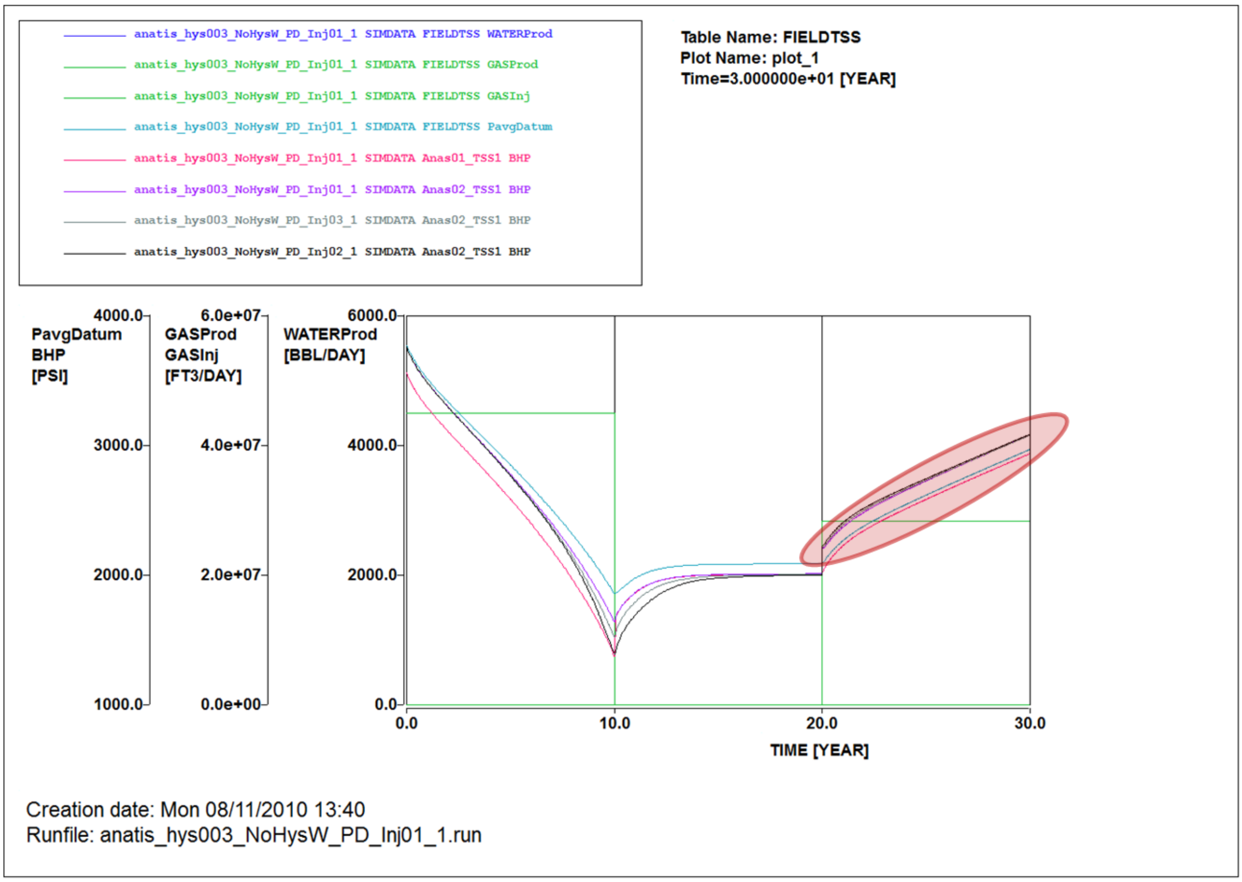

Figure 3-13. Average reservoir pressure, bottom hole pressure (both production and injection period) and rates, showing little difference in injection BHP due to different relative permeability end point in case where wells have a crestal position

The most pessimistic scenario is for wells completed in the flanks of the structure with the open section for injection at the bottom of the Captain D, partially or totally covered with brine from the aquifer encroachment (this is not the case for the current Goldeneye wells). The impact of relative permeability will be important. Simulation results from sensitivity cases where k_{rw} at S_{gr} = 0.6 and 0.1 are shown in Figure 3-14.

In this case, the area surrounding the wellbore will be preferentially saturated with brine and the relative permeability effects will be enhanced due to the forces needed to displace water away in order to inject CO_2.

Current relative permeability models are based on a reinterpretation of legacy data, which does not include any CO_2 specific measurements. Uncertainty ranges were developed and extended to encompass any differences that might be caused by CO_2 compared to hydrocarbon gas. A new SCAL laboratory programme was completed after this report was issued. It comprised a combination of ambient condition measurements and reservoir condition floods with CO_2 targeted at the key data uncertainties. An initial analysis of the results confirms the validity of the ranges used in the injectivity assessment, so that there is no immediate requirement to update any of the existing reservoir models.[7]

[7] SCAL Report. Doc No: SP-F_PE010-SCAL Report.

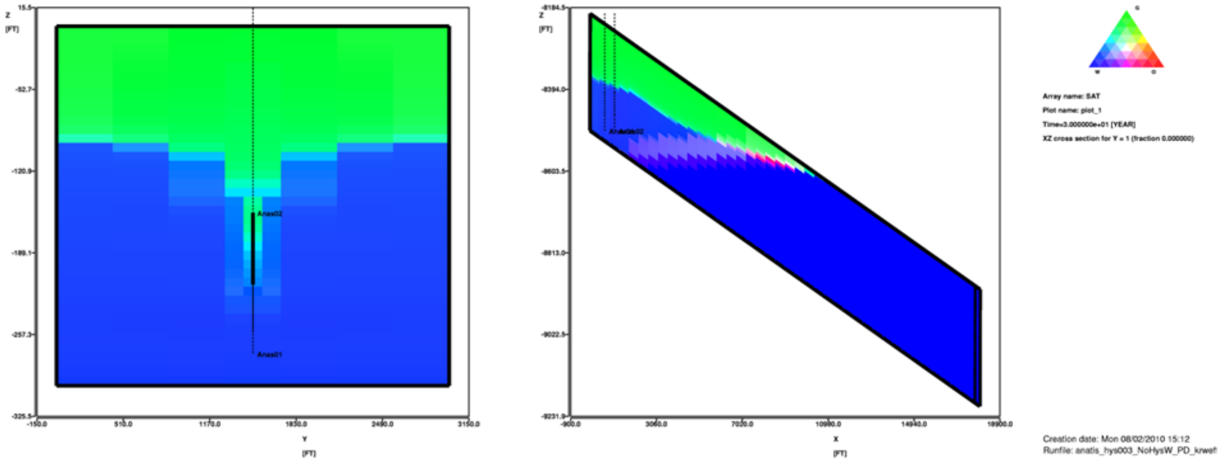

Figure 3-14. Cross section of simple box model. Ternary saturation diagram. Injector located in a flank

In addition, simulation showed that a prolonged transient effect could occur due to a quick gravity segregation of CO_2 and brine. CO_2 injected moves rapidly to the top of the reservoir leaving the perforations filled with brine again, making it difficult to inject. However, this extreme case is not expected to happen in Goldeneye because the wells will remain with the current completion intervals.

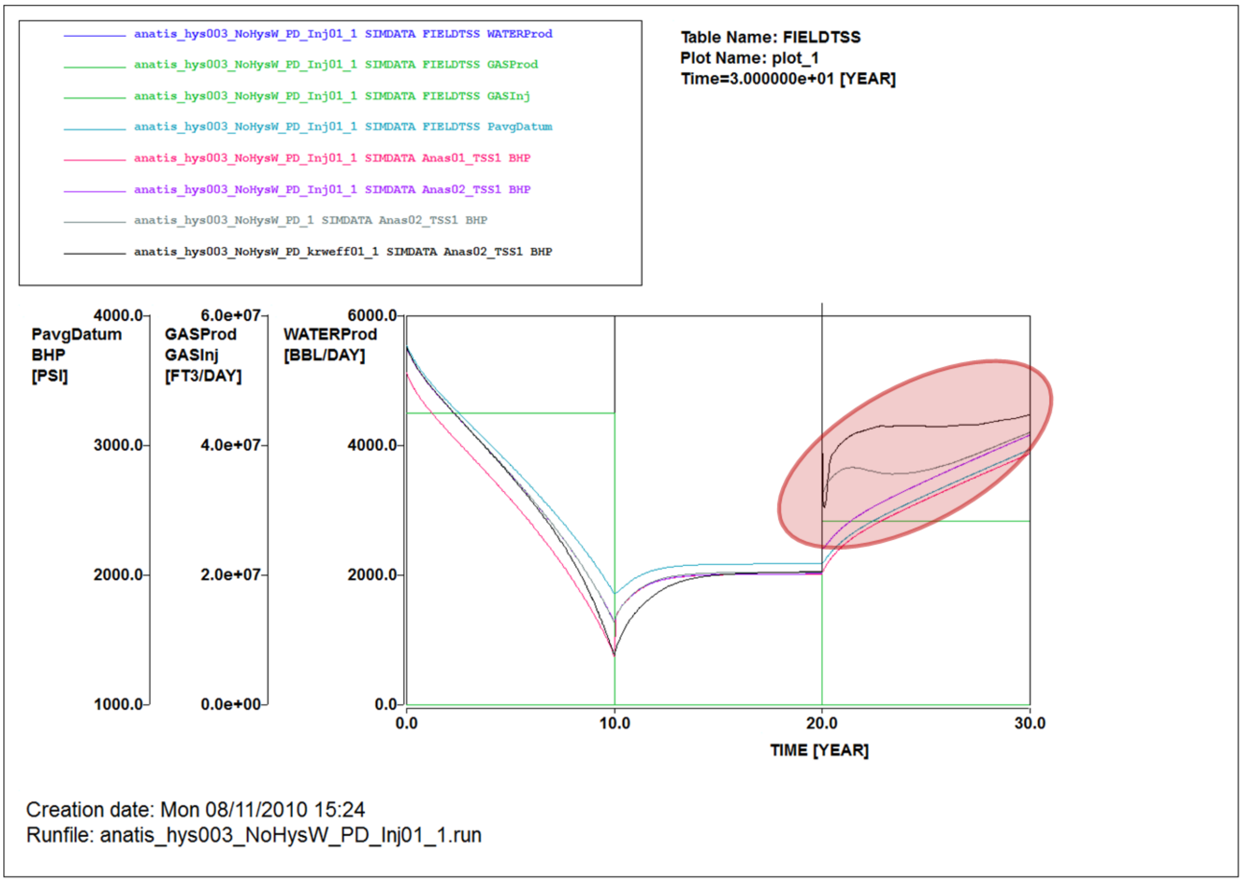

Figure 3-15. Average reservoir pressure, bottom hole pressure (both production and injection period) and rates, showing large difference in injection BHP due to different relative permeability end point in case where wells are in the flanks

Careful consideration must be taken into account regarding the full field model and real data from the permanent downhole gauges in order to establish the probability of having the gravel pack covered with brine due to the movement of the hydrocarbon-water contact. Nevertheless, results showed that as long as the gravel pack is at the top of the interval, no severe effects will be faced from water relative permeability.

Various other sensitivities were performed to assess the impact of additional water relative permeability parameters, whilst gas relative permeability and all other parameters were held constant. Results have demonstrated that hysteresis in water relative permeability has little effect on CO_2 distribution and injector bottom hole pressure, hence injectivity. Changes in water relative permeability Corey exponents from 2 to 3 and 5 also have very minor impact on the CO_2 plume sizes and distribution of CO_2 in water and gas phases.

4. Injectivity declining over time

4.1. Flow Reversal

The wells were completed with a screen and gravel pack in the lower completion. The gravel pack was provided as the main filter to avoid sand production from the wells, and was designed considering the grain size in Goldeneye and recognized oil industry design criteria.

In a production system, the gravel will act as the main filter of the formation sand whilst the screen will act as the filter for the gravel. In general, the gravel limits the size of the particles that come in contact with the screen and reduces the velocity at which particles contact the screen.

By reversing the flow, from the hydrocarbon production phase to the CO_2 injection phase, there might be some re-accommodation of fines currently embedded in the gravel pack under hydrocarbon production.

It is likely that formation failure has occurred in Goldeneye due to the level of depletion combined with the rock strength. Fines might have been trapped / embedded in the gravel pack, which is designed for this function. The well productivity has not decreased with time.

Upon flow reversal the formation fines currently embedded in the gravel pack could be mobilized and could then become trapped against the formation (like an external filter cake). In this situation the fines would then create an additional pressure drop, thereby reducing the injectivity in the well.

The effect of this pressure drop is considered low due to the following reasons:

- Well productivity stable with time.

  Indication of a limited volume of fines being trapped with time as the pressure drop in the wellbore has been stable.

- Captain D is well sorted sandstone

  Completed in the top of the D sand where the sand sorting is better. Fines percentage in the Captain D is very small

- Gravel pack designed considering the general criteria in the oil industry
- Industry experience in underground storage with sand control

This low risk can be further reduced with an injectivity test. However, the value of information of carrying an injectivity test solely for this is low, as the risk is considered to be manageable.

The mitigation to overcome this issue is to drill a sidetrack and to install a new gravel pack. This avoids the trapping of solids in the lower completion during the injection phase.

4.2. Gravel pack and formation plugging

. On commencing CO_2 injection, there is the potential that any solid debris present in the pipeline could become mobilised or dislodged and travel down the pipeline to the wellbore, potentially impairing injectivity by physically obstructing the path of CO_2 into the reservoir. The potential risk associated with pipeline debris transport is, therefore, related to the amount and, to some extent, the type of debris in the pipeline prior to commencing injection of the CO_2. As the pipeline is 105km long 20" diameter, even a small film of debris may represent a significant risk to injectivity.

There are two main types of debris that could be present in the Goldeneye production pipeline

- Organic Debris

  The Goldeneye field has been producing gas & condensate and small volumes of predominantly condensed water since field start-up. To date negligible amounts of hydrocarbon have been produced from the oil rim of the Goldeneye field. Consequently, it is fair to assume that there will be negligible solid hydrocarbon (wax or asphaltenes) present in the production line, as the potential for these types of deposits to form was characterised as being strongly dependent on oil rim production.

- Inorganic Debris

  In addition to organic deposits it is possible that there are inorganic solids present in the production pipeline. Sand and clays produced from the reservoir along with corrosion & scale products are all potential sources of inorganic solids that might be present in the pipeline. As there has been limited formation water production during field life, it is likely that there has been little or no scale precipitation in the pipeline to date. It is likely that if there are any inorganic solids present in the pipeline, they would be corrosion products or sand & fines produced from the reservoir.

  Fines deposits are probable but sensors at the wellhead do not indicate sand production from the wells.

The quantity of solids that will be present during the injection operation is currently unknown. The fact that the CO_2 will be dry reduces the risk of having corrosion products injected into the wells.

Risk Mitigation

There are two main mitigation measures to the problem. The first may be applied during the commissioning of the pipeline for CCS and the second during injection operations:

- **Pipeline Management**

  The first measure being considered is an intelligent pig run of the pipeline to enable the integrity status of the pipeline to be fully characterised

  The offshore pipeline will then be cleaned during the commissioning phase of the CCS project. Removal of the solids and liquids during this phase is very important to ensure the long term integrity of the pipeline and the lower completion / formation. However, given the geometry of the pipeline (20" diameter and ~105km long) it is operationally difficult to remove all the particles currently present in the pipeline. It is not expected that all the particles will be removed during this cleaning operation.

  Displacement of the current content of the pipeline (debris as fines or corrosion products and liquids water and MEG) into the wells prior to CO_2 injection is not acceptable.

- **Filtration**

  In an injection system, solid particles bigger than a critical size will start to accumulate internally at the screens, gravel and the formation. Smaller solids can pass the screen but can accumulate at the gravel. Still smaller solids can travel through the gravel and even smaller solids can sail through the formation.

Very small particles can be accepted in the injection wells as they will not result in plugging at the screens / gravel pack and formation. The Lower Completion specifies a maximum particle size of 17 micron to avoid the plugging of the lower completion and suggests 6 microns as the maximum particle size to avoid formation plugging. This is using the accepted guidelines in the oil industry for flow in a porous media:

- Particles larger than 1/3 of pore throat size will bridge.
- Particles smaller than 1/7 of pore throat size will flow through the matrix without plugging.
- Particles between 1/3 and 1/7 of pore throat size will invade and impair the porous media
- Pore throat size is 1/6 of particle size in a packed sand matrix with reasonable sorting.

The value for the lower completion (screen – gravel pack) considers the characteristics of the installed equipment.

Normally the value for the particle size compatible with the formation (under matrix injection) is estimated using core flood lab experiments and experience in similar formations. The value in Goldeneye was calculated using the average pore throat from petrophysical analysis (mercury injection capillary pressures) and the normally accepted rules in the oil industry for particle management. The average pore throat is in the order of 35-40 micron in line with the average permeability of the formation. In the case that the value needs to be optimised then core flood analysis will require to be carried out.

The third party supplier of the screens has indicated that they can be used for CO_2 injection. There will therefore be no modifications required to use the installed screen for injection purposes.

There is experience in water injection projects with similar types of screens.

The main operating practice in water injection projects with sand control is safeguarding the injection system by having a tight control on the water specifications namely solids content and size. In some Shell projects the water specification calls for a maximum particle size of 5 micron. Normal practice is in the order of 17 microns.

4.3. Dis-bondment of pipeline coating

The offshore pipeline was installed with an internal epoxy coating. The internal coating is a solvent based cured epoxy. The coating was not installed to protect against corrosion in service, it was installed to provide short-term corrosion protection during the pipeline storage and transportation. The thickness of the cured epoxy is between 30-80 microns.

The long term integrity of this layer is considered to have a minor risk on the CO_2 injection because of:

- Experience with similar types of cured epoxy in Enhanced Oil Recovery (EOR) projects, where such coatings have operated for decades showing no issues. However, there is no data on the performance of the installed cured epoxy coating currently installed in pipelines in CO_2 service.
- Coating disbonding is not expected during normal operating conditions. It can occur in uncontrolled depressurization.
- Coating manufacturer's recommendations and application data suggests a low risk of disbondment.

- Information available on epoxy coatings from literature is supportive of a low risk of disbondment.

Although coating disbondment is therefore not expected, there is still some degree of uncertainty of the coating response under CO_2 exposure.

Should there be any occurrence of disbondment during operation, then particles ranging from small solids to relatively large fractions of coating may be formed, which could subsequently clog or completely block the gravel pack / formation, thereby reducing injectivity. The mitigation for this case is to have a tight control on the CO_2 quality being injected into the wells using a filtration system on the platform.

4.4. Joule Thomson cooling upon CO_2 injection into the reservoir

A Joule Thompson cooling effect can be expected when CO_2 undergoes adiabatic expansion upon entering the formation. This phenomenon might reduce the temperature to levels where potential problems would occur – for example, high CO_2 viscosity, freezing of residual water, hydrates formation and fracturing. However, the likelihood of encountering CO_2 expansion problems in Goldeneye is very low with small changes in bottom hole temperature.

The injection conditions in Goldeneye include relatively high reservoir pressure, small delta pressure between the well and the reservoir and low injection temperature. These are adequate to avoid cooling of the CO_2 due to CO_2 expansion. This is demonstrated below:

The Joule Thomson coefficient under the injection conditions is low.

- 20°C - 2,100psi (145bar): 0.0378°C/bar
- 20°C - 3,850psi (266bar): 0.0084°C/bar
- 40°C - 2,100psi (145bar): 0.099°C/bar
- 40°C - 3,850psi (266bar): 0.0268°C/bar

The normally applied delta pressure in the reservoir would be between 100 to 300psi (according to the inflow calculations). Assuming a worst case of 500psi (34.5bar) then the change in temperature due to CO_2 expansion will be as follows:

- 20°C - 2,100psi (145bar) - 500psi DD: 1.3°C
- 20°C - 3,850psi (266bar) - 500psi DD: 0.3°C
- 40°C - 2,100psi (145bar) - 500psi DD: 3.4°C
- 40°C - 3,850psi (266bar) - 500psi DD: 0.92°C

4.5. Halite Precipitation

This problem has been observed in salt-saturated formation water reservoirs, and is caused by water evaporation around the wellbore due to CO_2 injection. The formation water in Goldeneye has a relatively low salinity which will minimise the effect of any potential salt precipitation.

CO_2 injection can lead to desiccation of the near wellbore of the injector due to the slight solubility of water into the CO_2-rich phase if the injection stream is dry. When a large number of pore volumes of dry CO_2 have been in contact with the water (i.e. close to the injector), all water might be evaporated. Since the salt dissolved in the water is not soluble in the CO_2 stream, it will remain and (upon complete dry-out) deposit as solid salt. In theory, this can lead to a reduction of absolute permeability in the near-wellbore zone, and might lead to a reduction in injectivity. A straightforward calculation and comparison to operational CCS projects, presented in the next two paragraphs, shows that for Goldeneye the risk of injectivity reduction due to this dry-out effect is minimal.

The Goldeneye water chemistry has a TDS concentration of around 56,000mg/l. The Goldeneye water is NaCl dominated brine (Na plus Cl concentration is 54,000mg/l). Even with full deposition of salt in situ the total salt deposited is only 56 grammes for every litre of formation water, almost completely as halite (solid NaCl). Since the specific gravity of halite is 2.17g/cc this corresponds to 26cc of solids for every litre of formation water. Even if the pore space would be completely filled by formation water (i.e. 100% water saturation) this would lead to a relative porosity reduction of only 26/1,000. Given the average porosity of 25% in the main reservoir sands (Captain D) this would reduce porosity from 25% to 24.4%.

It should be noted that around most injectors the water saturation is likely to be lower, for two reasons:

- Initial water saturation in Goldeneye is only approx. 13% on average going down to 7% around crestal wells. During the production phase this will have increased for some of the wells when watering out, but at least the crestal wells will only have partially watered out at the end of production.
- Even for a fully watered out well, the initial water saturation upon injection is only (1-residual gas saturation). Moreover, as has been shown in core flood experiments and modelling studies, dry-out only starts to become significant after some of this water has been displaced by injected CO_2. The water saturation at the start of significant dry-out depends on the relative permeabilities, but especially for a high permeability sandstone like in Goldeneye will be close to residual, which for such a sandstone is approx. 10-20%.

Therefore the relative porosity reduction is only [0.07-0.20]*26/1,000 = [2-5]/1,000, and therefore the porosity only reduces from 25% to [24.88-24.96]%. This is a very small reduction. Even if much of the salt deposition would occur in the pore throats (which have a relatively large diameter in Captain D due to its high permeability) it is not expected to have a measurable effect on permeability and therefore injectivity is expected to be unaffected by the build-up of the dry-out zone.

Therefore for Goldeneye the risk of injectivity impairment due to salt deposition in the dry-out zone consider to be low.

4.6. Hydrates

Hydrates can be precipitated in the presence of water and hydrocarbon or CO_2 at high pressures and low temperatures.

4.6.1. Hydrates Formation

The formation of hydrates is only possible when water is present in significant enough quantities and the temperature and pressure of the fluids are within the hydrate formation window. The Hydrate curve for CO_2 and Goldeneye hydrocarbon and their mixtures in the presence of a *free water phase* are shown in Figure 4-1(Hydrate region is to the left of the curve). The hydrate deposition curve depends on the composition. Hydrocarbon hydrates are formed more easily compared to CO_2 hydrates in terms of temperature. For instance, at 200bar (2,900psi) pressure and in presence of water, hydrocarbon hydrates can be formed at temperatures below 22°C whereas CO_2 hydrates only form below 11°C.

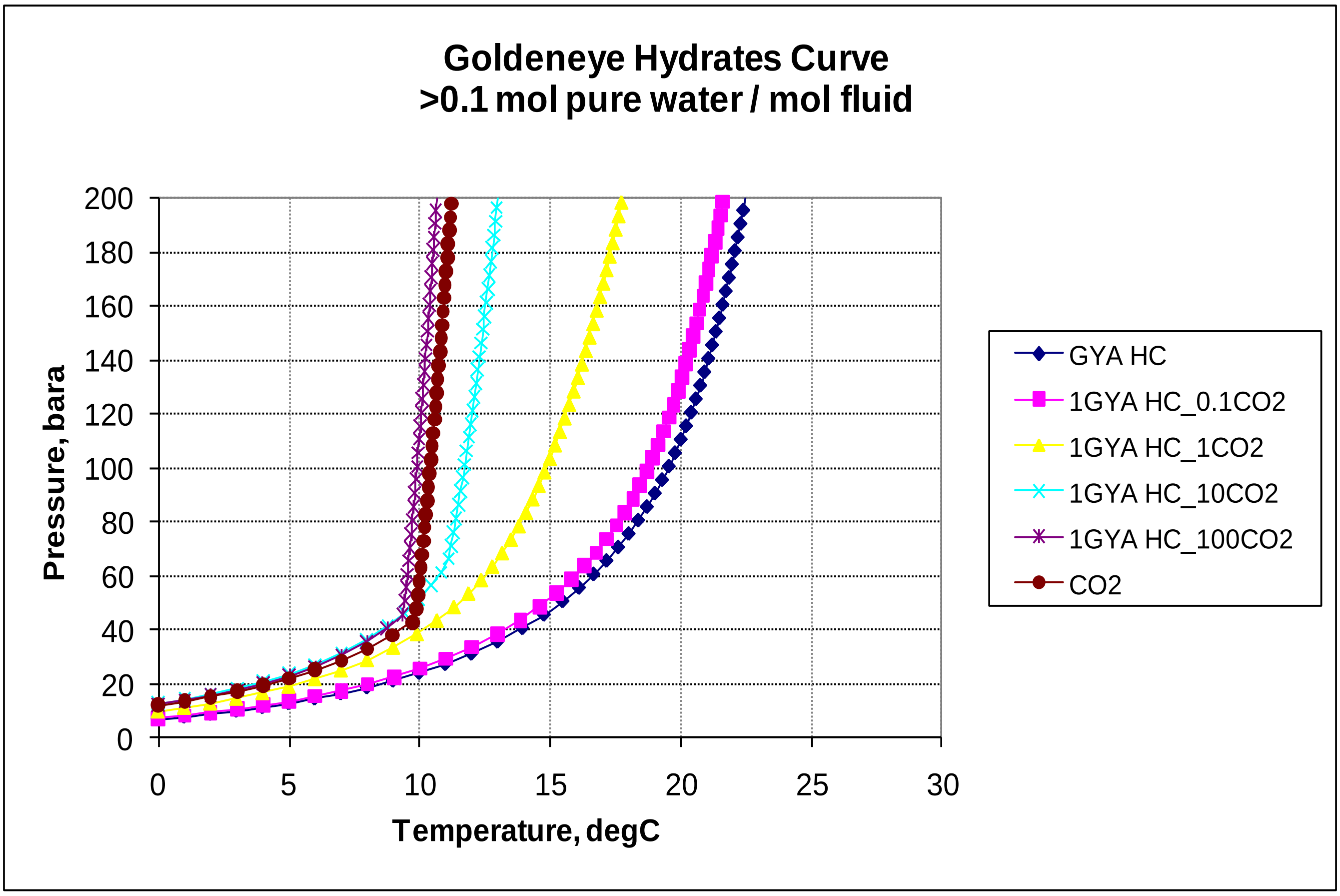

Figure 4-1 Hydrate Deposition Curve

The Steady State Injection conditions are expected to be between 20 to 35°C (most likely in the 20°C scenario). The absolute minimum bottom hole temperature in an adiabatic injection is 17°C.

4.6.2. Wellbore simulation

During hydrocarbon production, water has encroached towards the Goldeneye gas cap and at least part of the well gravel pack will be surrounded by water at the time when injection starts. The trapped gas saturation is estimated to be 25% hence some methane will remain near the well. This is miscible with CO_2 so will eventually be displaced by the injected CO_2.

The initial injection of CO_2 will drive water away from a well and will cool the reservoir. If the well is then shut in this water may well return into the cooled part of the reservoir where hydrates could potentially form.

Simulation Model

To investigate the issue regarding the water returning to the wellbore during closed-in conditions and the initial cooling of the reservoir, a compositional reservoir simulation model has been used with a 'pseudo thermal' option. This option models the flow of heat with the fluids and the heat transfer to the surrounding rock, but does not model heat transfer by conduction through the reservoir and from the rock above and below the reservoir. It therefore probably exaggerates the temperature reduction from injection and represents a worst case. Another model assumption is that water does not vaporise into the CO_2 rich phase. If this was modelled, the remaining water saturation within the cooled zone in the immediate vicinity of the injector would be lower (and could be zero at the injection intervals). This could further reduce the risk of hydrate forming. At 20 °C and 200 bar CO_2 in contact with water contains 0.3 mole % of water, this increases to 1.65 mole % at 83 ° C. At the expected injection rates this implies approximately 0.5 days to 3 days for the water to be vaporised by the injected CO2 within a 1 m radius around the well. Experiments within Shell confirm this process and show that brine saturated core plugs become completely dry after about 1000 PV injection of supercritical CO2 (at 45 ° C).

The model is a simple dipping box model with constant properties and represents approximately one quarter of the Goldeneye reservoir – and is designed as a simulacrum of the full field model. The model is similar to the one described in Section 3.5 but with extra grid refinement around the injection well. The grid blocks containing the well are 6 ft across. The permeability is 500mD and the porosity 23%. There is an aquifer at the edge of the model. The model GIIP is 219.5Bcf, approximately one quarter of the Goldeneye GIIP. There is a small initial oil rim. A crestal well produces for 10 years with a cumulative production of 15.3Bcf, which is a similar percentage of GIIP to that predicted by the FFM. After 10 years production the reservoir is shut in for 5 years to allow the fluids to equilibrate and the pressure to rise. CO_2 is then injected through a crestal well for 10 years at 1,500 tonnes per day which is equal to 28.3MMscf/day, approximately one quarter of the planned field rate.

Results

A number of cases have been run with different reservoir parameters and well positions. The Goldeneye wells are open to flow from the top of the reservoir to an approximate depth of 8,400ft TVD except for GYA03 which is open to flow to about 8,480ft TVD as it is lower down on the structure. Two cases have been modelled, one with 100ft of perforations and one with 60ft of open to flow lower in the reservoir. In both cases the wells start off surrounded by water.

Figure 4.2 shows a cross section through the model just before injection starts illustrating the remaining gas cap and the water flooded zone.

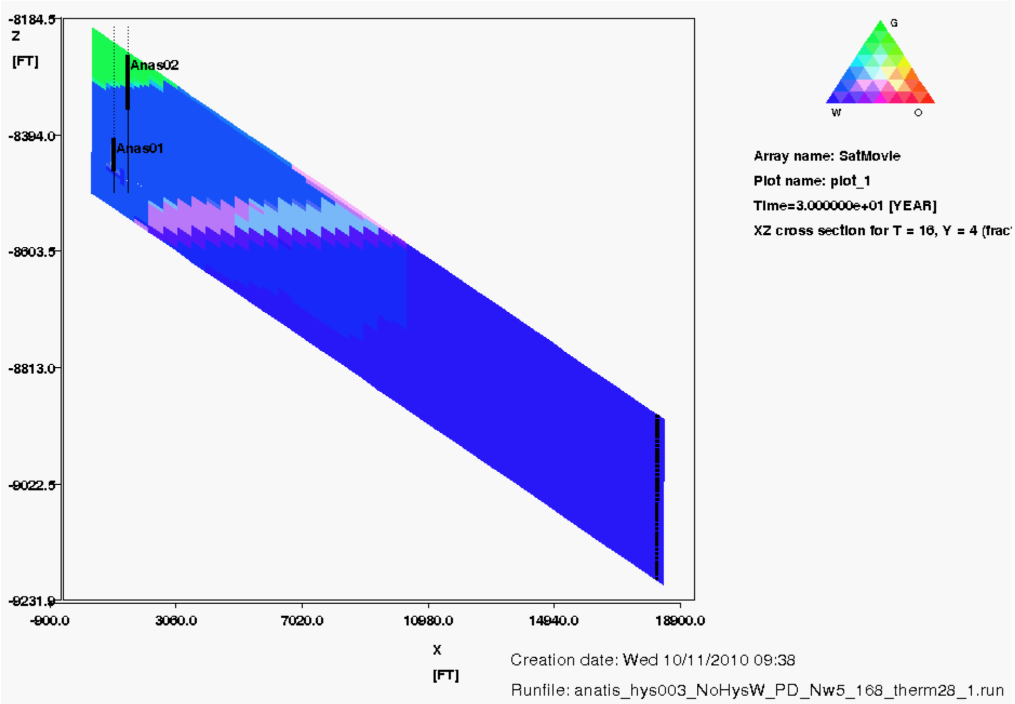

Figure 4-2 .Cross Section through Model After Production and Before CO_2 Injection

Figures 4.3 and 4.4 show the saturation distribution after 30 days injection and the corresponding temperature distribution. The CO_2 has displaced the water and gas immediately adjacent to the well and cooled the rock near the well. The water saturation is reduced to just above 20% while the gas is totally displaced by CO_2. Although CO_2 is miscible with the reservoir gas and significant displacement of the gas will occur, it is possible that some reservoir gas might remain trapped in isolated pores but at a much lower saturation than the 25-30% residual gas saturation. Due to preferential injection in the gas zone, the top half of the well is cooled to slightly less than 30°C while the bottom half of the well has yet to reach this temperature. It takes about 30 days to cool the 6 ft block containing the well. Simulations with a finer grid with a 0.8ft block at the well show the temperature falling below 30°C after 9 days.

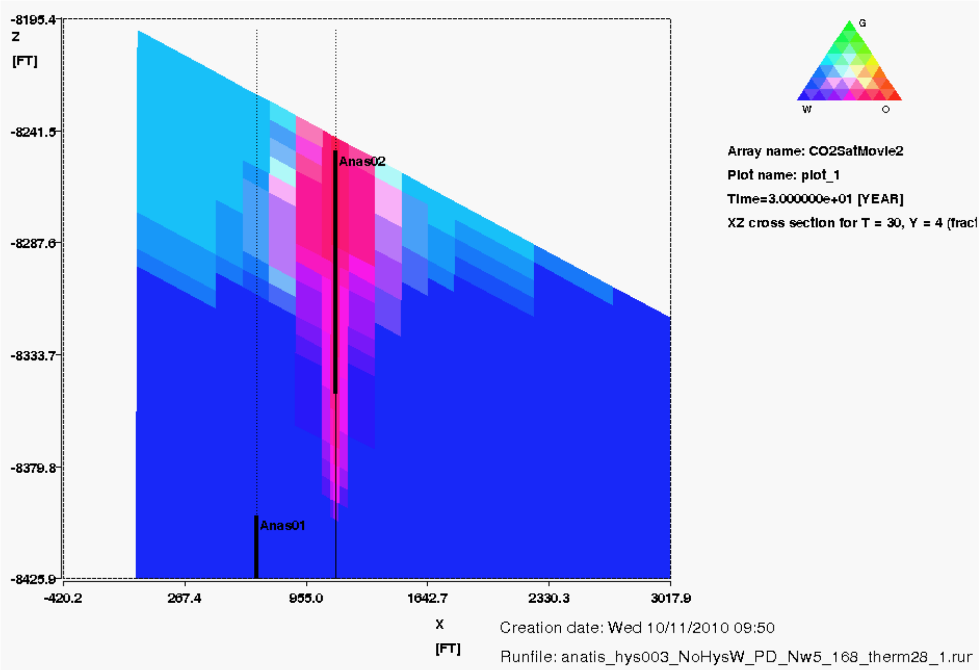

Figure 4-3. Saturation Distribution in Model After 30 Days Injection (Red CO2, Green Hydrocarbon, Blue Water)

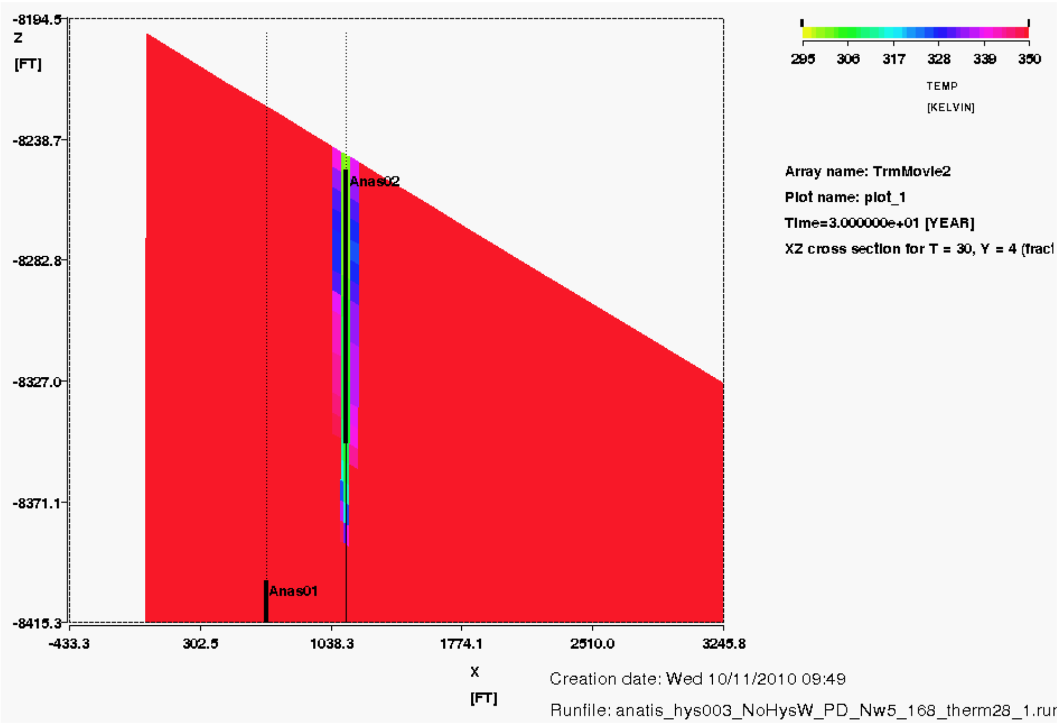

Figure 4-4. Temperature Distribution in Model After 30 Days Injection – Injection at Top of Reservoir

Figure 4.5 illustrates the case where injection is into the middle of the reservoir in the water flooded zone. In this case the temperature reduction is similar with the temperature at the well just above 30°C.

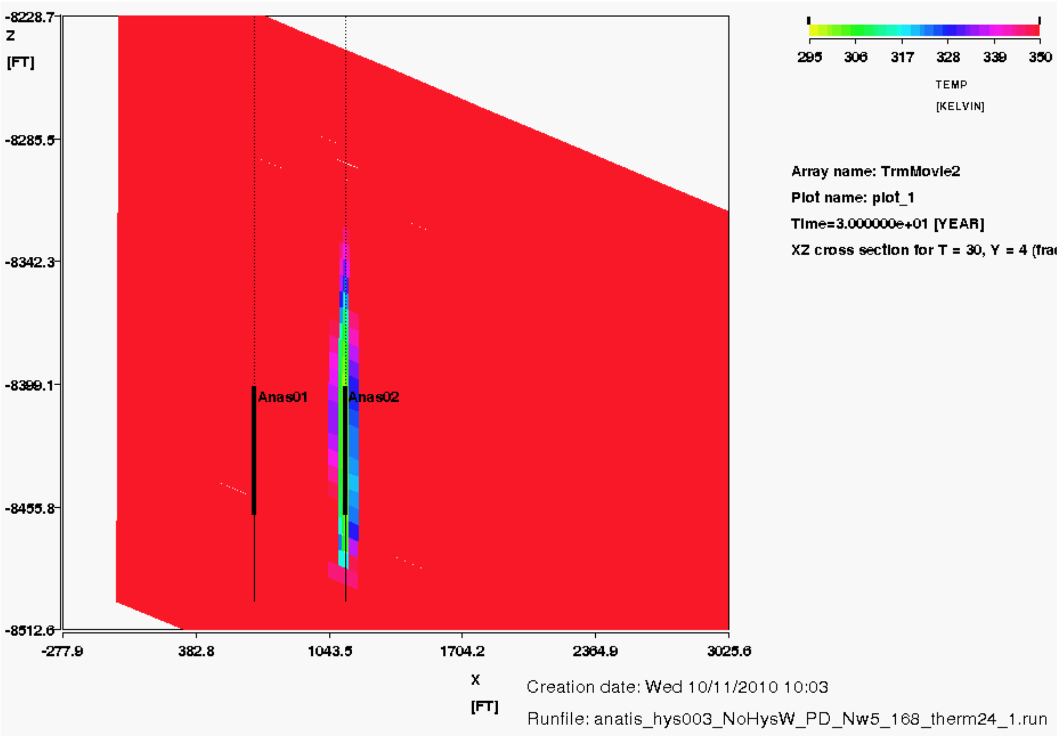

Figure 4-5. Temperature Distribution in Model After 30 Days Injection – Injection in Mid Reservoir

A number of cases have been run where the model has been shut in for a number of days after a period of injection. The aim of these cases was to investigate the movement of water into the cooled zone after the well is shut in to see whether there is a danger of hydrates forming. For the case with the well at the top of the reservoir, Figures 4.6 and 4.7 show the temperature and water saturation along a cross section through the well in layer 10 (75ft from the top of the reservoir) for a number of times after the well is shut in. The temperature and water saturation hardly change. The temperature in the model only changes by a small amount when the well is shut in due to the assumption that heat is only transported by the fluid. In reality the cooling effect of the injected CO_2 would slowly dissipate as heat is conducted through the reservoir rock.

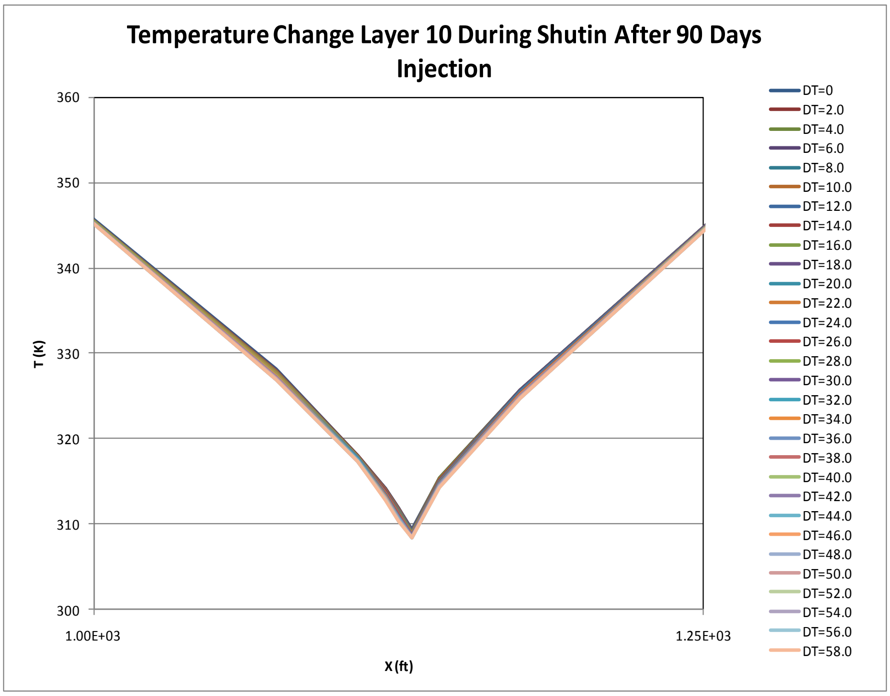

Figure 4-6. Temperature Change for Well at Top of Reservoir during Shut in after 90 Days Injection – Layer 10 through Well

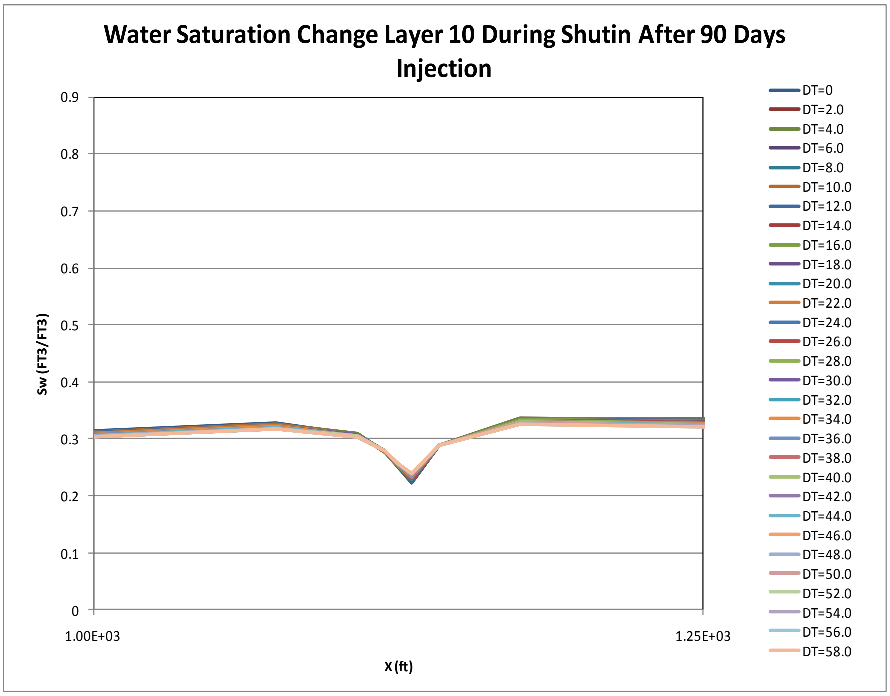

Figure 4-7. Water Saturation Change for Well at Top of Reservoir during Shut in after 90 Days Injection – Layer 10 through Well

Figure 4.8 shows the change in water saturation for layer 20 below the base of the well. Here a much larger change in saturation can be seen. However, after 180 days injection the water saturation change at this point is very small even after 60 days shut in.

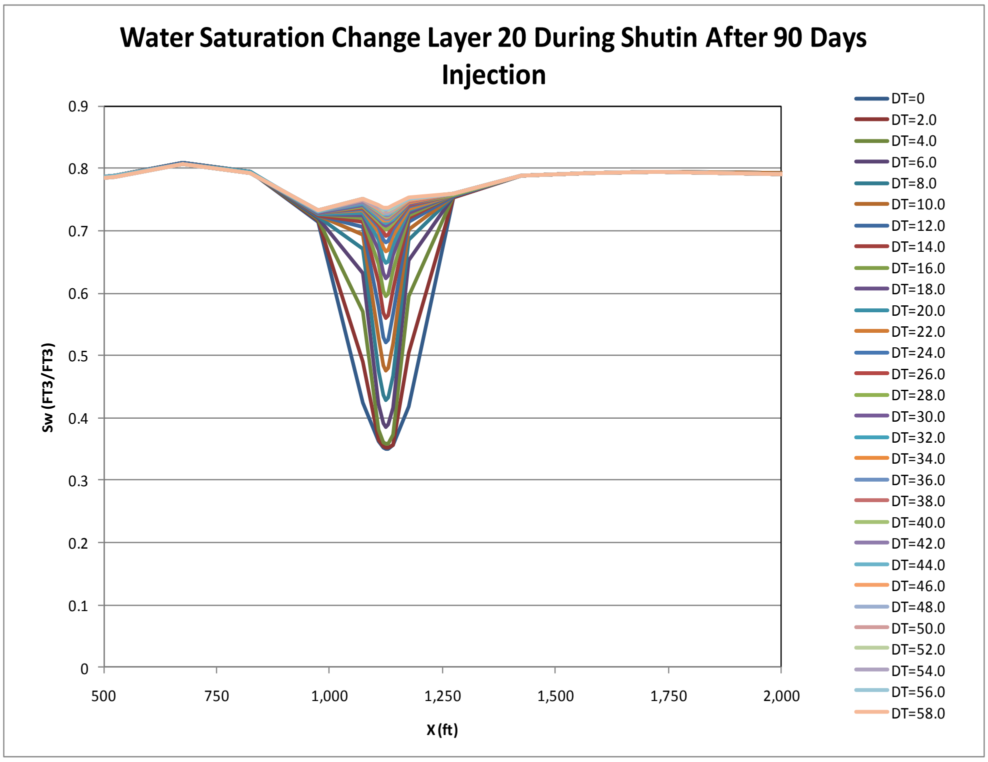

Figure 4-8. Water Saturation Change for Well at Top of Reservoir during Shut in after 90 Days Injection – Layer 20 below Well

For the case with the well perforated in the middle of the water flooded zone the water movement is more rapid, Figure below illustrates the change in water saturation at the middle of the well when it is shut in after 180 days injection. After one year's injection there is very little change in saturation at the well once it is shut in.

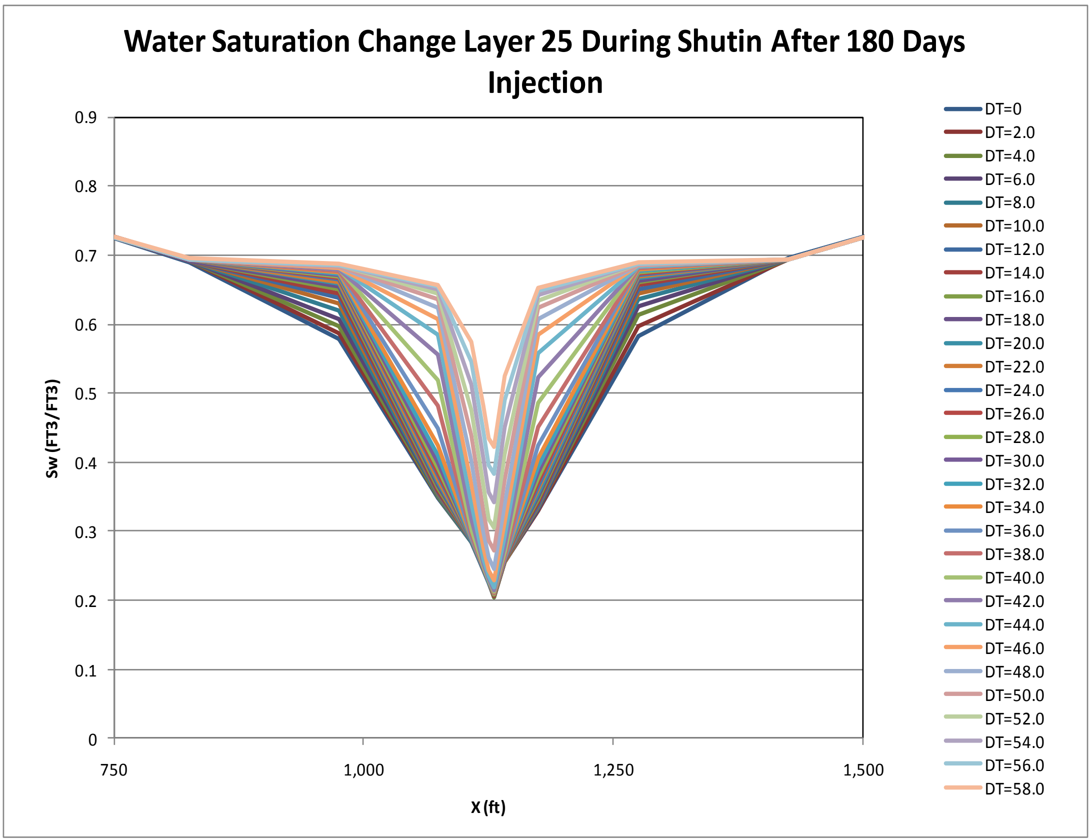

Figure 4-9. Water Saturation Change for Well in Mid Reservoir during Shut in after 180 Days Injection – Layer 25 through Well

Modelling Summary

The model results indicate that the reservoir near the well bore will start to fall below 30°C after about 9 days based on a 0.8ft grid block size at the well. During this period most of the methane will be flushed from the area adjacent to the well bore and water saturation in the model is reduced to around 25%. The high velocity of the injected CO_2 near the wellbore will also reduce the water saturation near the wellbore through evaporation although this has not been modelled. In the model runs where the grid block containing the well was 6 ft across the temperature at the well bore fell more slowly illustrating that the initial cooling is concentrated in a small area around the wellbore.

Once the well is shut in, the temperature will change only slowly and water will start to move back into the swept zone. For a well open to flow in the top half of the reservoir near the gas zone the water will start to flow back around the well if the injection period is less than 180 days but the top half of the well remains free of water after only 30 days injection as it was near the gas cap to start with.

A well open to flow in the water flooded zone will need to have had more than 180 days injection to keep the water from moving back to the wellbore when the well is shut in.

The exact details of temperature and saturation changes near the wells will depend on the particular well location and the injection rate but model results should be representative of the well behaviour.

4.6.3. Risk Summary

Initial Injection Conditions (<1-3months)

According to the hydrates formation modelling, wellbore modelling, and expected CO_2 pressure and temperature, Hydrates can be a potential problem during the initial period of injection due to the presence of formation water and hydrocarbon gas when injecting CO_2 into the formation.

Mid/Late Injection (>1-3 months)

At later stages, the hydrates potential problem will cease due to the following factors:

- The water will be displaced away around the wellbore by the CO_2. Even after closing the well for approximately one month the water is not entering the wellbore from the aquifer below the lower completion. Additionally, the CO_2 injection can lead to desiccation of the near wellbore of the injector due to the slight solubility of water into the CO_2-rich phase if the injection stream is dry. When a large number of pore volumes of dry CO_2 have been in contact with the water (i.e. close to the injector) all water will have evaporated.
- The other factor is that the hydrate deposition will change from hydrocarbon to CO_2 hydrate deposition curve requiring colder conditions to form hydrates. The CO_2 hydrate deposition requires in the order of 11°C to from hydrates, which is below the predicted lowest injection temperature under steady state injection and even under adiabatic injection.

Well Start Up

The main risk during a well start up is the hydrate deposition in the tubing and not in the formation. The wellhead temperature of the CO_2 will be approximately 4°C, which is well to the left of the hydrate deposition curve considering the presence of free water. In the case that water is added to the well (e.g. well intervention) or suspected to be in the well (e.g. initial injection conditions) then hydrate inhibitor should be used during the start up.

4.6.4. Risk Mitigation

The formation of hydrates in the well or near wellbore could potentially reduce or completely arrest injection of CO_2. The cooling of the injection well and the surrounding reservoir matrix induced by the injection of CO_2 have the potential to create conditions favorable for the formation of hydrates. This assessment is based on the assumption that both formation water and hydrocarbon gas will be present initially in the well and the surrounding reservoir matrix. To eliminate the potential for hydrate formation, it is considered prudent to continuously inject a liquid chemical hydrate inhibitor during those periods when conditions for hydrate formation are favorable.

Using a fine scale reservoir simulation model, it has been calculated that favorable conditions for hydrate formation are present during the injection of CO_2 for a period of up to a 3 months after the initial injection of CO_2. During this period, it is anticipated that continuous hydrate inhibition will be required. Beyond this period, the conditions in the well and the surrounding reservoir matrix are not favorable for hydrate formation and therefore hydrate inhibition will not be required.

The liquid chemical hydrate inhibitor employed for inhibition of hydrates will be either methanol or a mixture of Mono Ethylene Glycol (MEG) and water. The final choice of hydrate inhibitor will primarily depend upon hydrate inhibition performance and its compatibility with existing injection infrastructure. It is envisaged that the chosen hydrate inhibitor will be applied to the well prior to injection of CO_2 to inhibit the water column present against hydrate formation. On commencing injection of CO_2 it is envisaged that the hydrate inhibitor will be injected continuously for a period of up to 3 months to ensure that the formation of hydrates is prevented.

4.7. Near Wellbore Asphaltene Deposition

High levels of carbon dioxide are known to destabilise asphaltene dispersions in hydrocarbons. As the composition of the hydrocarbon present in the CCS injection wells is assumed to be the same as that produced from the reservoir over the last 6 years, it is assumed that the total quantity of asphaltenes present in the gas hydrocarbon on a percentage volume basis is zero. Therefore the risk of depositing asphaltenes that could lead to injectivity impairment is nil.

The Oil Rim present initially in Goldeneye is expected to be smeared out by the gas production and aquifer encroachment into the reservoir. The likelihood of having asphaltenes from the oil rim deposited in the CO_2 injector wellbore is very low due to the small amount of oil from the liquid hydrocarbon produced in Goldeneye being reported. The wells were completed in the top of the Captain D and structure away from the original position of the oil rim.

4.8. Near Wellbore Wax deposition

Injecting cold CO_2 in a reservoir containing hydrocarbons has the potential to condense the heavier alkene fractions leading to wax deposition. However, on review of the Goldeneye gas / condensate composition it is clear that the amount of heavy end hydrocarbons is very small. Furthermore, previous laboratory testing has shown that the cloud point of the Goldeneye condensate could not be reached at -2.2°C and that the calculated cloud point of the condensate was predicted to be -6°C. As the temperature of the near wellbore is not predicted to get below 17°C during CO_2 injection, even assuming no heat transfer from the formation, the likelihood of wax deposition is nil.

5. Mitigation Options Summary

There are a number of different proactive activities that will be carried out to minimise the risk of not being able to inject the required amount of CO_2. Some of them have been discussed in the previous sections. A summary of them is included in section 5.1 below. There are also reactive options which might be available should we encounter injectivity issues, and these are outlined in 5.2. Injectivity management of the risk is discussed in Section 5.3.

5.1. Proactive measures

The following actions have been identified as proactive mitigation options to reduce the risk of poor injectivity.

- Pipeline cleaning

  The pipeline needs to be cleaned before the CO_2 injection. It is not acceptable to displace the current content of the pipeline (debris as fines or corrosion products and liquids water and MEG) into the wells prior to CO_2 injection.

- CO_2 filtration

  Filtration will be required on the platform to the adequate levels of solids size to avoid lower completion plugging and erosion and formation plugging. The current estimated size is 6 microns.

- Chemical injection

  Injecting chemicals to avoid the hydrate precipitation during the initial stages of injection. This may be ceased once the formation water and hydrocarbons are displaced from the wellbore as the hydrates forming ingredients will have been removed.

- Number of wells

  In theory, it would be possible to operate only three wells to inject the CO_2 from the capture plant during the lifecycle of the project. Additional well(s) or redundant injectors will be converted to CO_2 injection to increase flexibility in terms of integrity and / or injectivity issues. This additional well can be used as a continuous injector in the event that injectivity problems are encountered.

An injectivity test was considered in order to reduce some of the uncertainties in injectivity. However, given the value of information, the complexity of the test and the cost it has been disregarded. Appendix A presents the analysis of this decision.

5.2. Reactive measures

Apart from proactive mitigations options described above, there are potential remedial activities which may be executed in the event that problems are encountered:

- Well stimulation

  Using the proper fluid and operation depending upon observation of the damage mechanism. For example water stimulation for halite precipitation. Most likely to be carried out with a stimulation vessel given the space limitation on the platform.

- Flow back

  This is a major operation for cleaning clogged solids on the screens. Might be applicable in the event of problems with pipeline coating disbonding.

  The planned platform configuration will not allow flow of the CO_2 hydrocarbons mixture into the process facilities. Most likely a well test package will be required.

- Others

  Consideration should be given to new technologies in the event of injectivity problems. This can be related to ultrasonic tools, heaters, etc.

- Sidetrack

  Sidetrack is always the last resort to restore injectivity, due to the high cost involved.

5.3. Injectivity Management

Initial injectivity problems are thought to be unlikely. The most probable cause of low injectivity is thought to be fines re-accommodation in the gravel pack resulting from the reversal of flow, and this might be difficult to rectify.

There are other mechanisms that can also cause deterioration of the injectivity with time, e.g. the impairment of the gravel pack or formation with particles or hydrates. The risk of this is also relatively high, although with these mechanisms there are a number of options for both pre-emption and treatment.

The overall picture is summarised in the following table:

Stage	Mechanism	Description	Risk probability before mitigation	Mitigation Options	Risk probability after mitigation
Initial Injectivity	Reservoir Parameters	High absolute permeability based on core and production information.	Zero	-	Zero
	Initial Skin	High initial skin but stable drawdown during production.	VL	-	VL
	Fluid Change - PVT	Different PVT properties from the current HC production to the CO2 injection.	VL	Injectivity calculation considering the change of fluids	VL
	Relative Permeability	Short term effect. Minor effect on injectivity in the long term.	VL	Simulation scenarios	VL
Injectivity deterioration with time	Fines Re-accommodation	Flow reversing will re-accommodate the fines embedded in the gravel pack (during the production phase) against the formation	L	Production conditions assessment	L
	Desbonding Pipeline Coating	Potential for epoxy disbonding of the offshore pipeline	VL	Filtration. Reactive - Flowback Sidetrack	VL
	Gravel Pack / Formation plugging	Plugging of the lower completion with particles. Sensitivity to big particles.	H	Filtration to the required levels Pipeline cleaning Reactive - Remedial activities - Stimulation	L
	CO2 expansion (JT effect)	Formation cooling due to JT effect.	VL	Reduced effect due CO2 bottomhole conditions	VL
	Halite	Water dry up due to CO2 injection. Salt precipitation	VL	Reactive - Remedial activities - Stimulation	VL
	Hydrates	Potential of Hydrate formation at the start of the injection due to hydrocarbon and water presence	M	Chemical inj. - Hydrate inhibitor	L

Table 5-1 Injectivity Management. Risk Reduction

Abbreviations

AHD	Along Hole Depth
CAPEX	Capital Expenditure
cm/y	Centimetre / year
DTS	Distributed Temperature Sensing
DPS	Distributed Pressure Sensing
EOR	Enhanced Oil Recovery
FIV	Formation Isolation Valve
FFM	Full Field Model
ICV	Inflow Control Valve
ID	Inner Diameter
MMscf/day	Million standard cubic feet per day
MEG	Mono Ethylene Glycol
OPEX	Operational Expenditure
PBR	Polished Bore Receptacle
PDG	Permanent Downhole Gauges
PVT	Pressure Volume Temperature
Ppb	Parts per billion
P_{wf}	Flowing Bottomhole Pressure
SAS	Stand Alone Screens
SCAL	Special Core Analysis
S_{gr}	Residual Gas Saturation
SSSV	Subsurface Safety Valve
TD	Total Depth
TOC	Top of Cement
TVD	True Vertical Depth
TWC	Thick Wall Cylinder
UCS	Unconfined effective stress
WH	Wellhead
XMtree	Christmas Tree

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

Appendix A. Injectivity test

An injectivity test was initially considered in a Goldeneye well to reduce the risk related to injectivity of CO_2 in Goldeneye. However, it is no longer recommended considering the limited reduction in uncertainties and the cost involved, as discussed below.

- The current production phase of Goldeneye is the best indicator of the expected CO_2 injectivity in Goldeneye.
- The ideal injectivity test should be carried out with the same fluid and conditions expected during the operating phase of the injection, CO_2 for the case of CCS.
- The length of any productivity / injectivity test should be tailored to the main uncertainties / risks considering the operational aspects of the test. If the test is too long to obtain meaningful results then the cost will increase significantly decreasing the value of the test. In other words, the test might be more expensive that the investigated risks.
- Another fluid (e.g. water, nitrogen, hydrocarbon) might be used, but the extrapolation of the results should be taken into consideration.
- Doing the test with water, hydrocarbon or nitrogen will only have benefits in terms of reducing the uncertainty in terms of fines re-accommodation in the gravel pack.
- In addition to the fines re-accommodation an injectivity test carried out with CO_2 will have small benefits with respect to the fluid change in terms of PVT, relative permeability and the risk of hydrates. The phenomenon related to fluid change is relatively well understood with a very low uncertainty. Reducing this further will not impact the project in terms of cost or decisions. There will be a reduction in Hydrates uncertainty from low to Zero. However, the current thinking calls for hydrate inhibition during the initial stages of injection.

The following Table presents the summary with the reduction of Risk / Uncertainty with respect to the current understanding of the injectivity in Goldeneye and the planned mitigation options. The table shows the value of the injectivity test over and above the current understanding.

Stage	Factor	Current View (including planned mitigation)	Current risk uncertainty (includes planned mitigation)	Risk/Uncertainty after Injectivity Test		
				with CO2	with N2	with Water
Initial Injectivity	Reservoir Parameters	High absolute permeability based on core and production information.	Zero	Zero	Zero	Zero
	Initial Skin	High initial skin but stable draw down during production.	VL	VL No added value	VL No added value	VL No added value
	Fluid Change - PVT	Different PVT from the current HC production to the CO2 injection. Already included in the calculations	VL	0 Minor effect on injectivity based on different PVT. Easy to calculate	VL Another fluid introduced in the system.	VL Another fluid introduced in the system.
	Relative Permeability	Minor effect on injectivity in the long term. Scal analysis. Easy to calculate the difference Different scenarios with simialr results	VL	0 Information added in terms of permeability to CO2.	VL Complications with different injection fluids.	VL Complications with different injection fluids.
Injectivity deterioration with time	Fines Re-acommodation	Flow reversing will re-accommodate the fines embedded in the gravel pack (during the production phase) against the formation. Production conditions assessment indicate not a bn important effect	L	VL Can give extra information in the short term	VL Can give extra information in the short term	VL Can give extra information in the short term
	Desbonding Pipeline Coating	Not expected. Filtration planned.	VL	VL Pipeline not used during the injectivity test	VL	VL
	Gravel Pack / Formation plugging	Plugging of the lower completion with particles. Sensitive to big particles. Filtration to required levels. Initial comissioning of the pipeline	L	L No added value. Injectivity test should be carried out with the specifications of particles	L No added value. Injectivity test should be carried out with the specifications of particles	L No added value. Injectivity test should be carried out with the specifications of particles
	CO2 expansion (JT effect)	Formation cooling due to JT effect. Reduced effect due CO2 bottomhole conditions	VL			
	Halite	Water dry up due to CO2 injection. Salt precipitation. Not expected	VL	VL No added value. It might be a long time effect.	VL No added value	VL No added value.
	Hydrates	Potential of Hydrate formation in the lower part of the well at the start of the injection. Hydrate inhibitor proposed for the initial injection period	L	VL Cold CO2 to understand the risk of hydrates	L No added value	L No added value

Table 0-1 Injectivity Test. Risk/Uncertainty comparison per and post test.

For a CO_2 injection test and based on the current knowledge of GYA wells, injecting CO_2 in the wells without carrying any modification to the well completion will jeopardise the integrity of the wells. This is related to the extremely low temperatures expected due to the Joule Thomson effect of the CO_2 and the related tubing shrinkage affecting the PBR in the well. Modifications in the well completion should be carried out prior to the injectivity test, leading to substantial upfront costs.