SUBSURFACE ISSUES FOR CO_2 FLOODING OF UKCS RESERVOIRS

S G Goodyear[(1)], I R Hawkyard[(1)], J H K Masters[(1)], C L Woods[(1)] and A J Jayasekera[(2)],

[(1)]**AEA Technology plc, Winfrith Technology Centre, Dorchester, Dorset, UK**

[(2)]**UK Department of Trade and Industry, 1 Victoria Street, London, UK**

Presented at IEA Collaborative Project on Enhanced Oil Recovery 23rd International Workshop and Symposium, Caracas, Venezuela, September 2002

ABSTRACT

CO_2 injection is a successful IOR technique applied in onshore fields, where the CO_2 is sourced from natural CO_2 reservoirs. Concern over greenhouse gas emissions has renewed interest in the potential for CO_2 flooding in the UKCS. CO_2 would be captured onshore, e.g. from power station emissions, and injected into UKCS reservoirs to improve recovery and leave CO_2 trapped in the reservoirs at the end of project life.

Experience from onshore CO_2 injection projections is reviewed. Tertiary CO_2 injection in North American fields regularly achieves incremental recoveries in the range 4-12% STOIIP with retained gas volumes of 10-25% HCPV. Gas utilisations of better than 8 Mscf/STB are usually achieved. Reservoir parameters for onshore projects are compared with typical UKCS conditions, and the key similarities and differences highlighted. Incremental oil production in onshore CO_2 WAG projects expressed in terms of reservoir barrels is related to the volume of CO_2 retained, and is consistent with a rule of thumb developed for offshore hydrocarbon gas injection projects. Based on literature correlations most UKCS fields are expected to be above the MMP for pure CO_2.

The impact of compositional effects and the operating temperature and pressure on offshore CO_2 injection performance is assessed using sector models of WAG and crestal (gravity stable) injection schemes. Reducing the operating pressure reduces the incremental recovery but decreases the volume of CO_2 required, although in the crestal injection model, the pressure can be significantly below the MMP before recovery is adversely affected. Temperature has a significant impact on WAG recovery, and needs to be considered if CO_2 is to be injected in parts of a reservoir that have been cooled by seawater injection.

INTRODUCTION

CO_2 injection is a successful IOR technique applied in onshore reservoirs. Historically, low cost CO_2 has been sourced from gas reservoirs with a high CO_2 content. Concern over greenhouse gas emissions is leading to the introduction of CO_2 trading schemes and possible changes in fiscal regimes. With the right reservoir conditions, injection of CO_2 into oil reservoirs can result in incremental oil with the added benefit of CO_2 sequestration. A typical case in point is the onshore Weyburn Unit project in Canada, which is injecting waste CO_2

from an industrial plant in the USA to give an expected additional 140 MMSTB oil production and disposal of 19 million tonnes (350 Bscf) of CO_2.

The physical properties and PVT behaviour of CO_2 with reservoir oils is qualitatively different from other gases considered in gas injection IOR projects. Pure CO_2 has a critical point at a temperature and pressure 1071 psia and 87.91oF respectively, which is within the temperature range of UKCS light oil reservoirs in regions cooled by waterflooding and the shallower viscous oil fields. CO_2 densities can approach 1 g/cc and may be greater than oil at reservoir conditions, giving scope for designing different types of injection strategy.

This paper reviews onshore experience of CO_2 injection from the standpoint of subsurface issues and examines the similarities and differences between onshore projects and potential UKCS projects. The impact of compositional effects and the operating temperature and pressure on offshore CO_2 injection performance is assessed using sector models of WAG and crestal (gravity stable) injection schemes.

OVERVIEW OF ONSHORE PROJECT RESULTS

There were 63 producing miscible CO_2 projects in the USA reported in the Oil & Gas Journal survey of March 2000 [1], and just one immiscible CO_2 flood. The operators most actively involved in CO_2 flooding were Altura and ExxonMobil, with Amerada Hess, Merit Energy, Oxy USA, Spirit Energy and Texaco also operating several floods each. There were 7 new miscible floods planned to start by 2002. There were also 5 producing CO_2 floods in Canada, all in the Joffre Viking field, operated by Numac Energy. The only operating projects outside North America were 5 immiscible floods in Trinidad (all operated by Petrotrin) and one in Turkey (operated by TPAO).

The oil targets to CO_2 injection include:

- Residual oil to water flooding in tertiary miscible CO_2 floods (e.g. most projects in the Permian Basin of Texas and New Mexico).
- Low porosity/permeability zones in heterogeneous formations (e.g. Dollarhide [2]).
- Transition zone oil [e.g. 3,4].

In many cases, the start of gas injection was accompanied by a change of flooding pattern (e.g. from 40 to 20 acre spacing or from inverted 9-spot to inverted 5-spot), complicating the interpretation of any incremental oil signal.

MISCIBILITY

Most onshore North American projects are tertiary miscible WAG floods. These fields were generally produced by natural depletion initially and subsequently re-pressurised by water flooding to above the CO_2 MMP before gas injection commenced [e.g. 5]. The effective residual oil saturation to water in the Permian Basin San Andres formation fields is typically in the range 35-40%, therefore there is a large target for miscible flooding. However, two near-miscible floods also showed good response [6]. Achievable residual oil saturations to miscible gas flooding are in the range 3-10%, determined from cores from swept zones [7] or simple material balance calculations [8]. The North Cross (Devonian) CO_2 flood is not fully miscible. However, core from the swept zone indicated a residual oil saturation of only 3%, therefore multi-contact miscibility was established even though the reservoir pressure was below the nominal MMP [7].

TYPE OF GAS INJECTION

The optimum injection strategy is determined primarily by the degree of gravity segregation in the flooding zone. Wettability is a significant secondary factor for horizontal gas injection projects, because it controls the tendency of the water phase to form barriers between the injected gas and unswept oil at the pore scale. Consequently, the optimum WAG ratio depends on the balance between the conflicting requirements of conformance control and tertiary recovery via reduction in effective residual oil saturation. Estimating this balance is a requirement of detailed assessments of gas IOR opportunities. Onshore CO_2 field experience suggests that continuous gas injection is optimum for water-wet rocks, whereas a 1:1 WAG ratio is optimum for oil-wet conditions. Recovery is a stronger function of slug sizes for mixed-wettability formations [9].

'Hybrid' WAG

A continuous slug of gas is injected initially, swapping to WAG when gas production becomes significant (e.g. the Dollarhide Devonian CO_2 flood [2]). This technique is effective when gas sweep is intrinsically efficient. It combines the advantages of a large early response, typical of continuous gas injection, with good sweep efficiency and efficient use of CO_2, typical of conventional WAG schemes. WAG cycles may be detrimental to injectivity, therefore water injection should be limited to areas of severe gas breakthrough. CO_2 breakthrough is not generally a problem in the Devonian formation in the Permian Basin, therefore WAG may not be warranted in most patterns. The initial 'continuous' slug is typically 8-12% HCPV of CO_2.

Classical WAG

This strategy is optimum in reservoirs where gravity override would be expected for continuous gas injection [e.g. 10]. Tapering the WAG ratio is a method of reducing CO_2 production. For example, the first 30% HCPV injection may be at a 1:1 WAG ratio, the next 10% at 2:1, and the final 10% at 3:1, followed by chase water.

SWAG

Miscible simultaneous water and gas injection (SWAG) has been tried in two CO_2 projects [10,11]. Although SWAG can simplify field operations, it may trap significant amounts of oil in water-wet rock if applied as a secondary process, or in regions where mobile oil has been bypassed by an inefficient waterflood [9]. Corrosion is potentially a greater problem in SWAG than in conventional WAG injection.

Gravity stable gas injection

There have not been many gravity stable gas injection (GSGI) projects in North America. One example is at Bay St Elaine [12]. A 33% PV slug of CO_2 solvent was injected into the top of a dipping water-drive reservoir. This was pushed downdip by injection of nitrogen gas. The CO_2 composition was tailored by the addition of CH_4 and n-butane to give the density difference required to complete the gravity-stable flood in the desired time period and also keep above the minimum miscible pressure (MMP) in the reservoir. The flood was actually only multi-contact miscible. A pilot GSGI CO_2 flood was performed in the Weeks Island field by Shell in 1978 [13]. The reservoir was sandstone, with an average permeability of 1200 md and dip of 26°. The residual oil saturation at the start of the gas injection was estimated as 0.22. The CO_2 was mixed with a few percent of methane to ensure gravity stability and the initial gas slug size was 24% HCPV. Produced gas was re-injected. The pilot is expected to recover 8.9% STOIIP, with gross and net CO_2 utilisation factors of 7.9 and 3.3 Mscf/STB, respectively.

CO_2 FLOOD RESPONSE

Incremental oil recoveries for successful CO_2 floods are illustrated in Figure 1 and 2.

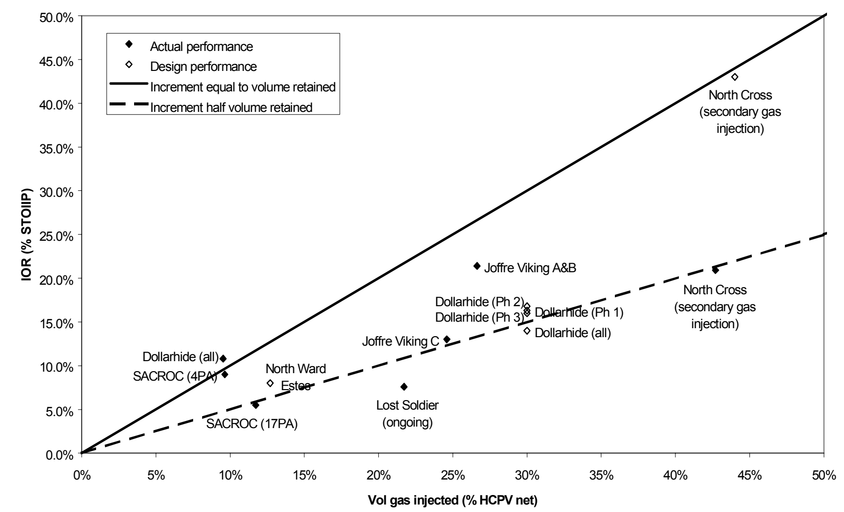

Figure 1 : IOR vs. net gas volume injected for onshore CO2 projects

The incremental oil recoveries range from 4% to approximately 20% STOIIP, for gross injected gas volumes of 10-70% HCPV. The Lost Soldier project was ongoing at the time of the report. The incremental oil recovery is expected to increase from 7.6% to 13.2% STOIIP ultimately, but the injected volume will also increase. The tertiary projects with high incremental oil recovery are the Joffre Viking A and B patterns and the Slaughter Estate pilot. Both of these are floods of two unconstrained pattern elements only, therefore there is considerable uncertainty in the estimates of STOIIPs targeted. The Dollarhide, SACROC (17PA), Lost Soldier and North Ward Estes results are all averages over at least 17 adjacent pattern elements, therefore these results are considered more reliable than those based on the performance of only a few elements. The SACROC (17PA) project is ongoing, and the final IOR is expected to be around 7.5% STOIIP. The Wellman project is a GSGI, to recover a thin oil rim.

In conclusion, the more reliable results illustrated in Figure 1 suggest that tertiary CO_2 injection in onshore North American fields regularly achieves incremental oil recoveries in the range 4-12% STOIIP.

The net gas volumes injected lie in the range 8-45% HCPV, measured relative to the STOIIP. The North Cross project had the largest retained volume, but this was a secondary gas

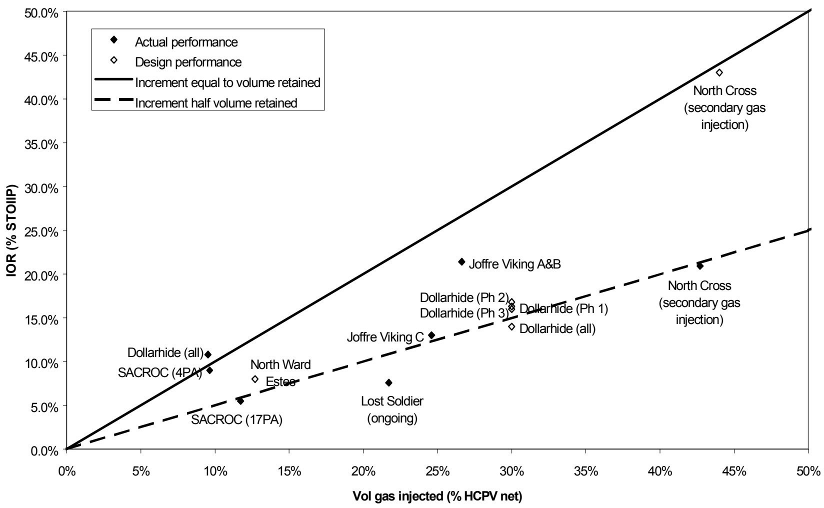

Figure 2 : IOR vs. net gas volume injected for onshore CO2 projects

injection, rather than a tertiary project. Retained volumes were typically 10-25% for tertiary CO_2 floods. The incremental oil production is generally between 0.5 and 1.0 of the volume retained in the reservoir, when both are expressed as a fraction of STOIIP, which is consistent with a rule of thumb developed for offshore hydrocarbon gas injection projects.

GAS UTILISATION AND ECONOMICS

Net gas utilisation provides an indication of the efficiency and therefore the economics of CO_2 injection. Net gas utilisation is illustrated as a function of injected gas volume in Figure 3 and Figure 4. The majority of projects have net gas utilisations of less than 8 Mscf/STB, and several have utilisations of less than 6 Mscf/STB.

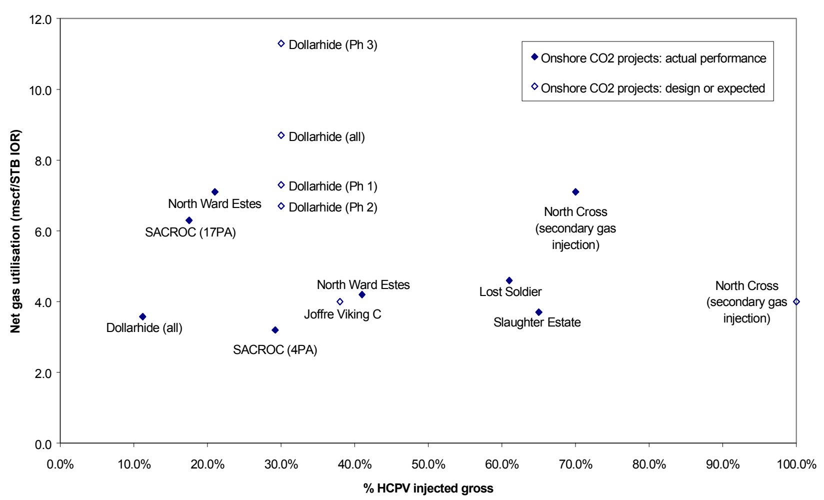

Figure 3 : Net gas utilisation as a function of gross volume injected for onshore CO_2 floods

The expected value for phase 3 of the Dollarhide Devonian flood is high, which increases the expected average performance over the whole field. However, the actual flood performance averaged over all phases has been significantly better than the design target so far. This flood is unusual in that it is operated at 3600 psi, whereas the CO_2 MMP is only 1600 psi. The reason for this policy is unknown, but it will have a detrimental impact on the flood efficiency, as discussed below.

The major flood management parameters affecting economics according to [9] are:

1. The CO_2 and water half-cycle slug sizes (typically 0.1-2% PV)

2. The WAG ratio (typically 1:4-2:1)

3. The ultimate injected CO_2 slug size.

It seems unlikely that the half-cycle sizes would have a large impact on economics within the range typical for a conventional WAG. There could, however, be a significant impact on discounted economics between hybrid and conventional WAG schemes.

The relevant CO_2 volume is the volume at reservoir conditions, rather than at the surface. It is therefore most economical to operate a miscible flood as close to the MMP as possible. This was demonstrated in the Wasson Denver Unit flood, where the reservoir pressure was reduced from 3200 psi to 2200 psi before CO_2 injection commenced, to improve the volumetric efficiency of the CO_2 but stay above the MMP of 1300 psi [14]. The Wolfcamp Reef GSGI flood was initially operated significantly above the pure CO_2 MMP , to allow miscible re-injection of the produced CO_2 -hydrocarbon gas. However, the pressure was subsequently reduced to near the CO_2 MMP, to reduce the CO_2 purchasing requirement, at the expense of gas separation [8,4].

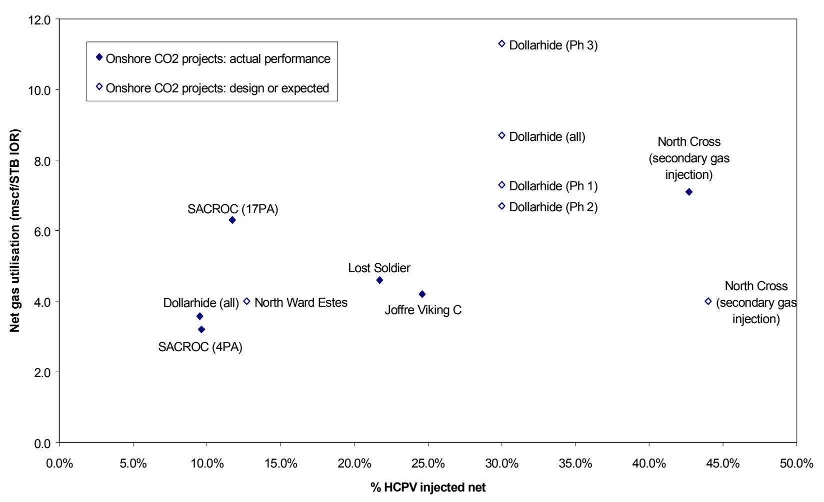

Figure 4 : Net gas utilisation as a function of net volume injected for onshore CO_2 floods

A significant decrease in effective residual oil saturation might be expected even for an immiscible GSGI scheme, due to gravity drainage, therefore the above discussion applies primarily to WAG projects. Gravity-stable injection might be performed below the MMP, to reduce the CO_2 formation volume factor, giving an additional improvement in utilisation. Another method of reducing the cost of gas for a GSGI project is to down-grade the gas composition as the flood progresses. This was modelled for the Wolfcamp Reef GSGI flood, where a miscible 'pancake' of CO_2 was displaced downdip by nitrogen [8]. It is unclear whether the strategy was actually implemented. The strategy was used in the Slaughter Estate Unit [15].

OVERVIEW OF ONSHORE PROJECT ISSUES

ADDITIONAL GAS CONTROL METHODS

Early breakthrough arising from channelling or override (usually unexpected because of poor reservoir description) can be hard to solve offshore. Onshore, the offending well or wells may be shut in, but offshore, there are fewer wells, therefore each one may be essential [11].

Simulations of the North Coles Levee CO_2 pilot suggested that gravity over-ride dominated the displacement efficiency. In this case, co-injection of gas low down and water higher up might improve the sweep [16].

Polymer and gel have been used, mainly to improve vertical sweep. Foams have been tried, to improve the mobility ratio between the CO_2 and reservoir crude, with mixed success [17]. Gel treatments were used to reduce channelling in the Lick Creek Meakin Sand Unit immiscible CO_2 project [18]. Attempts to reduce gravity-override in the Joffre Viking field by foam treatments were unsuccessful, because the foam did not propagate into the formation [10].

CO_2 ROCK AND FLUID INTERACTIONS

CO_2 shows more complex phase behaviour with reservoir oils compared to hydrocarbon gas. In addition its relatively high solubility in water and the associated reduction in pH significantly affects reservoir chemistry.

PVT

Phase behaviour in CO_2 floods is discussed in [19], with the following main conclusions:

- Up to 5 phases can co-exist in a CO_2 flood: aqueous, liquid hydrocarbon, liquid CO_2, gaseous CO_2 and solid asphaltene precipitate.
- The actual number of phases depends on pressure, temperature and composition.
- Gas condensing into a second liquid phase can be significant at temperatures just above the v critical temperature (88° F) and near the CO_2 saturation pressure at lower temperatures. This would only occur behind the temperature front offshore.
- CO_2 displacement efficiency may increase as the pressure is decreased until the MMP is reached.

- It is necessary to consider all this complex phase behaviour when predicting flood performance, therefore compositional simulation is essential in the detailed appraisal of projects.

Hydrate formation

CO_2 hydrates will form at a temperature of approximately 50°F over the pressure range expected in UKCS reservoirs and upstream of the separators [29]. Hydrate formation has been experienced in the North Cross Devonian Unit, which has an original formation temperature of 80° F [20], where it usually occurs in wells with high GORs and high CO_2 cuts. The temperature will be reduced in the production tubing, due to the expansion of the gas entering the wellbore.

Wettability

Core floods and capillary tube visual cell tests give inconsistent changes in wettability due to miscible CO_2 flooding. CO_2 reduces the brine pH, and there is some experimental evidence that this reduces water-wetness in capillary cells. However, some experiments on intermediate-wet Texas cores suggest CO_2 flooding increases their water-wetness [9]. Furthermore, wettability may be primarily controlled by 'pore coatings' in the reservoir.

Fines and particulate production

CO_2 may leach minerals (calcite and siderite) from sandstone and carbonate, increasing permeability. This is important for sandstone, because these minerals contribute to the cementation of the rock [9]. Fines and particulate deposition were experienced in the Dollarhide Devonian CO_2 flood [2]. Water handling was modified to eliminate fines and particulates from the injection stream and this reduced the amount of fill in injectors. Ref. [9] concluded that dissolution, precipitation and particle invasion/migration may occur during CO_2 WAG, but the evidence is not conclusive.

Scale formation and deposition

CO_2 injection tends to exacerbate any $CaCO_3$ scaling problem, because the bicarbonate (HCO_3^-) concentration in the produced water increases [21]. The CO_2 is expected to reduce the pH of water in-situ by 2-3 units. This acidic water dissolves calcium from the limestone rock or from cementation minerals in sandstone formations, increasing the Ca concentration in produced water. Pressure reduction on production would then (a) increase $CaCO_3$ scaling tendency directly, and (b) increase the produced water pH as the CO_2 comes out of solution, which would also increase $CaCO_3$ scaling tendency. The reduced pH of produced water following CO_2 breakthrough, may decrease the effectiveness of scale inhibitors being applied to control $BaSO_4$ scaling [22].

When CO_2 enters producers it expands and cools, in common with other gases, reducing the BHT. Further cooling occurs at choke points. This may cause increased scaling, paraffin/asphaltene deposition and wellhead freezing. The impact depends on where the reservoir and wellbore temperatures lie on the solubility vs. temperature curve for each mineral. Also, the pH is decreased, therefore it is necessary to select inhibitors/treatment chemicals that are effective at low pH.

IMPACT ON INJECTIVITY

The term ‘injectivity’ is used loosely in this section, to refer to the relationship between pressure gradient and flow rate both in the near-wellbore region and deeper in the formation.

Fields experiencing decreased injectivity

WAG is often detrimental to injectivity [e.g. 2], although a comprehensive review of injectivity in 2000 found no reports of injectivity loss alone severely impairing project economics [9]. Average loss of water injectivity after the first gas cycle is around 20% for onshore West Texan projects in oil-wet carbonate reservoirs [17,9,23]. This is generally compensated by decreasing the WAG ratio [e.g. 24], increasing the injection pressure, drilling more injectors [17] or converting to horizontal injectors [23].

In the Slaughter Estate Unit (dolomite), most mature patterns suffered a 40% loss of injectivity for CO_2 and 57% loss for water. In this field, injection was below the reservoir parting pressure [15]. Attempts were made to overcome reduced injectivity in the Wasson Denver Unit (dolomite) by increasing the injection pressure above the fracture pressure. This caused out-of-zone losses, however, therefore more injectors were drilled instead [14]. The operators were able to swap to continuous gas injection in some patterns in this unit. Some producers were converted to injectors in the Sundown Slaughter Unit (dolomite), to avoid losing gas out-of-zone by injecting above the formation parting pressure. The wells were already as close together as was economically viable in this unit [25]. All these units have temperatures in the range 100-110° F, therefore there is some doubt whether the injectors would be thermally fractured, in contrast to injection wells in most North Sea fields.

Reduced injectivity could be seriously detrimental to a WAG project if it led to a shortfall in voidage replacement that reduced the reservoir pressure below the MMP for the injected gas [11].

Reduced injectivity may also be caused by wellbore heating that closes thermal fractures, or hydrate or asphaltene precipitation in the near-wellbore region [11].

Fields experiencing increased injectivity

There are some cases of injectivity improvement during WAG, for example the SACROC unit [26]. Water injectivity increased after injection of liquefied CO_2 in the Sharon Ridge Canyon Unit, which is a limestone reservoir [21]. This may be due to increased permeability caused by dissolution of calcium from the limestone rock by carbonic acid (i.e. formation water + CO_2). Increased injectivity was attributed to a similar effect in the carbonate Goldsmith San Andres Unit [6].

Relative permeabilities

Water injectivity would be expected to decrease after gas injection, from normal 3-phase relative permeability considerations. A reduction commensurate with this cause was observed in the North Cross (Devonian) Unit CO_2 flood [7]. Injectivity loss was also attributed to relative permeability effects in the Slaughter Estate Unit [15].

CO_2 relative permeabilities in West Texas carbonates can be 0.01 times oil relative permeability end points, therefore errors in CO_2 relative permeabilities can cause large errors in injectivity predictions. Errors in CO_2 relative permeabilities affect gas production and injectivity more than oil recovery [9].

GAS SUPPLY AND COMPOSITION

This section notes information about injected gas compositions and the management of produced CO_2.

The strategy in the Wolfcamp Reef Reservoir Wellman Unit GSGI project, was to re-inject all produced gas, rather than separate and re-inject only the CO_2. Consequently, planning included slimtube experiments to determine the MMP at reservoir temperature for CO_2 containing various amounts of hydrocarbon impurities [8]. However, a later report [4] states that the produced gas contains approximately 10% NGLs that have to be removed and sold before the CO_2 is re-injected. The difference is due to a change of ownership and change of operating philosophy. The new owners decided it was more cost-effective to operate as close to the pure CO_2 MMP as possible, i.e. at the lowest possible pressure, to reduce CO_2 purchase costs.

At the Sundown Slaughter Unit, only production from wells in which CO_2 had broken through was fed to the CO_2 removal plant. Fluid from other wells was processed normally. It was possible to use an existing CO_2 removal plant locally owned by other operators for a fee, therefore there was some flexibility to exceed the unit's design capacity [25].

The Lost Soldier, Tensleep formation contains sour crude. A CO_2 WAG project was implemented. CO_2 was produced in association with 1700 ppm H_2S, which had to be reduced to <100 ppm before the CO_2 could be re-injected. The project was subsequently successfully converted to sour CO_2 re-injection [27].

The North Cross Devonian Unit was produced by hydrocarbon gas injection after an initial period of primary depletion. CO_2 flooding was then initiated, and the produced gas was a mixture of CO_2 and hydrocarbon. Gas from different producers was segregated, depending on whether it contained >60% or <60% CO_2. The high CO_2 content gas was re-injected into injectors that initially injected pipeline CO_2 (i.e. imported, pure CO_2). The lower CO_2 content gas was re-injected into updip wells that had previously been hydrocarbon injectors. These were expected to prevent excessive up-dip movement of the purer CO_2, rather than achieve miscible oil displacement [7].

In the Slaughter Estate Unit, the initial gas composition was 72 mol% CO_2 + 28 mol% H_2S. A pilot miscible WAG ran from 1976 to 1984. The WAG comprised 25% HCPV at a 1:1 WAG ratio, followed by 40% HCPV of chase gas over 11 WAG cycles. The chase gas was a varying composition of residue gas and nitrogen [15].

The CO_2 for the Springer A sand flood in the NE Purdy Unit was sourced from an anhydrous ammonia fertiliser plant. The re-injected produced gas contained 85-92% CO_2. The flood was designed to be miscible, at least for the imported gas [28].

The CO_2 composition in the Bay St Elaine Field GSGI project is tailored by the addition of methane and n-butane, to optimise the density difference for the flood [12].

COMPARISON BETWEEN UKCS RESERVOIRS AND ONSHORE CO_2 PROJECTS

In this section the reservoir conditions in typical onshore CO_2 injection projects are compared to UKCS fields, and the likely impact on the performance of CO_2 injection considered.

RESERVOIR TYPE

Significant differences exist between onshore fields in which CO_2 has been injected and UKCS fields, including:

- The majority of UKCS fields are sandstone reservoirs, many of the US CO_2 injection projects are in carbonate reservoirs
- UKCS light oil fields are deeper and therefore at higher pressures and temperatures
- UKCS fields are typically developed with line drive patterns, fields are produced using 5- or 9-spot pattern flooding with significantly smaller well spacing (see Figure 5)

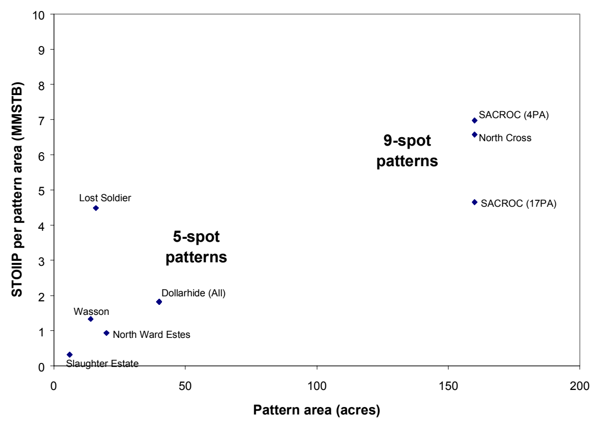

Figure 5: Permian Basin CO_2 flood pattern area

- UKCS fields operate at higher rates with more restrictive water-cut limits
- UKCS fields are generally of higher quality and gravity forces are more important. This may provide more attic targets for WAG flooding and scope for crestal gravity stable injection schemes.
- The effective residual oil saturation to water in most of the Permian Basin San Andres formation fields is in the range 35-40%, giving a large target for miscible flooding. Residual saturations may be lower in the UKCS, for example in high permeability regions with high throughputs or in zones that have been influenced by cross-layer gravity drainage
- Many North Sea fields have strong aquifer support which could limit the opportunities for pressure management.

PRESSURE AND TEMPERATURE

Figure 6 shows pressure and temperature plotted for UKCS light oil reservoirs and onshore US CO_2 injection projects.

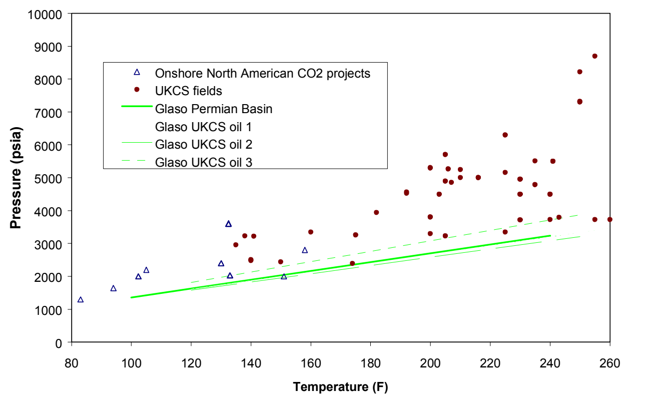

Figure 6: Onshore CO_2 project and UKCS reservoir conditions

The greater depth of UKCS fields means that pressures and temperatures are significantly higher . The CO_2 density in the formation is compared for North American projects and UKCS fields in Figure 7. This shows that CO_2 densities in UKCS fields would be in the range 0.5-0.75 g/cc, which is similar to those in CO_2 flooded Permian Basin fields, despite the different pressure and temperature regimes. Consequently, similar surface volumes of CO_2 would be required to sweep a given reservoir volume in both cases. This is different to the situation for hydrocarbon gas. Typically, a factor of 2-3 more hydrocarbon gas might be required to flood a given reservoir volume in a North Sea field than in a Permian Basin, San Andres formation reservoir.

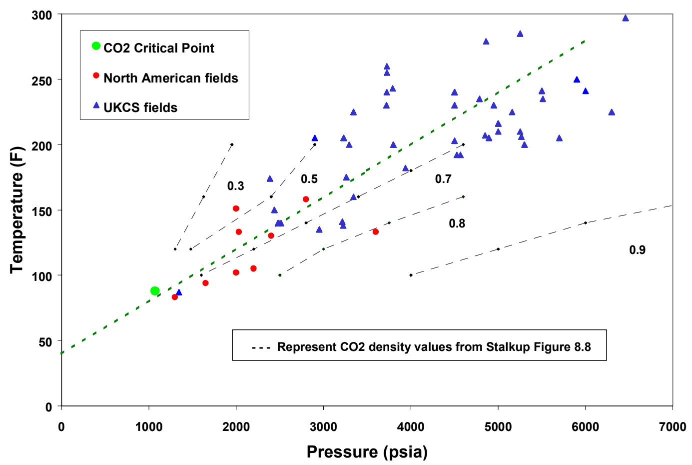

Figure 7: Comparison of CO_2 density at onshore North American CO_2 project and UKCS reservoir conditions

These differences in hydrocarbon gas and CO_2 compressibilities potentially favour CO_2 projects at North Sea conditions. In addition to this, lower volumes of gas might be required for GSGI projects, because it might be possible to reduce the reservoir pressure below the MMP, as discussed in Sections 5 and 6. The above discussion applies to regions of the field at the original reservoir temperature. There would, however, be extensive cooled zones around existing water injectors in UKCS fields. If cold CO_2 were injected into these wells, its density might be increased to 0.8-1.1 g/cc [29].

Imported CO_2 would probably have a density close to 1 g/cc on arrival at the platform, therefore it might be able to be injected via a pump, without requiring compression. The relatively high density at the formation face could improve the inflow profile relative to that expected for hydrocarbon gas. Furthermore, gravity segregation might be reduced in the cooled zone around the injectors, due to the small density difference between the CO_2 and reservoir fluids. However, there is also a danger of hydrate formation.

In contrast, recycled CO_2 would be compressed and might, therefore, be hot on arrival at the formation face, with physical properties similar to those for hydrocarbon gases in conventional gas injection schemes. The injection of hot gas might tend to close thermal fractures, reducing injectivity, if continued for a long time. This might be significant for the first water slug in a hybrid WAG scheme, but would not be expected to be important for GSGI or a conventional WAG project.

MISCIBILITY

The potential for miscibility of CO_2 with UKCS oils has been assessed using correlations and compositional modelling. Three correlations have been used, the Cronquist [30] and Alston [31] correlations are specific to miscibility of CO_2 with oil whereas the more recent Glasø correlation [32] is an adaptation for CO_2 /oil systems of a more generalised MMP correlation. The three correlations can give widely varying results so the use of the three together gives some indication of the degree of uncertainty of the MMPs predicted. Cronquist met with limited success in matching reported experimental MMPs, and being the simplest form is probably the least reliable. Alston and Glasø give better matches, with results covering a good range of temperatures and pressures, however, the majority of the temperatures and MMPs reported are *lower* than those for the oils in the current study, bringing applicability into question.

Compositional modelling has been used to infer MMPs from simulations of slim tube displacements. There is no well defined set of guidelines for the choice of binary interaction coefficients for CO_2 and hydrocarbon components, and three different sets were used based on previous modelling studies of North Sea fluids.

Table 1 summarises the results obtained. For a given oil, the range in MMP values predicted by the correlations varies from 300 to 850 psi. MMPs predicted by the EOS modelling are higher on average by 200-500 psi. For the heavier oil E, full miscibility was not achieved, however it was possible to predict pressures at which 85-90% of the oil was produced after 1.2 HCPV injection of CO_2. The heavier fractions drop out and are not produced. This result cast doubt on the relatively low MMP predicted by the correlations for oil E.

Figure 6 also shows predicted MMPs using the Glasø correlation for a representative range of light oils, compared to onshore CO_2 injection projects and UKCS fields. This suggests that CO_2 will be miscible in most UKCS fields, with some fields providing significant scope for improving CO_2 utilisation if it is possible to operate at lower pressures. Miscibility would be improved in cooled (water flooded) regions of the fields.

	Predicted MMP (psi)				
Oil	A	B	C	D	E
Cronquist	2790	2936	3231	3228	2666
Alston	3081	3572	3926	3694	3010
Glasø	2839	2811	3070	2987	2494
EOS modelling	300-3400	3200-3700	3500-4200	3150-4000	1950-3900

Table 1 : Comaprison of predicted MMPs for five UKCS oils

COMPOSITIONAL MODELLING OF CO_2 WAG

WAG injection was investigated using a compositional sector model extracted from a UKCS field model. The grid was refined both areally and vertically, giving a model size of 39x9x26 (NXxNYxNZ). A single producer and injector were modelled for both the waterflood and WAG strategies.

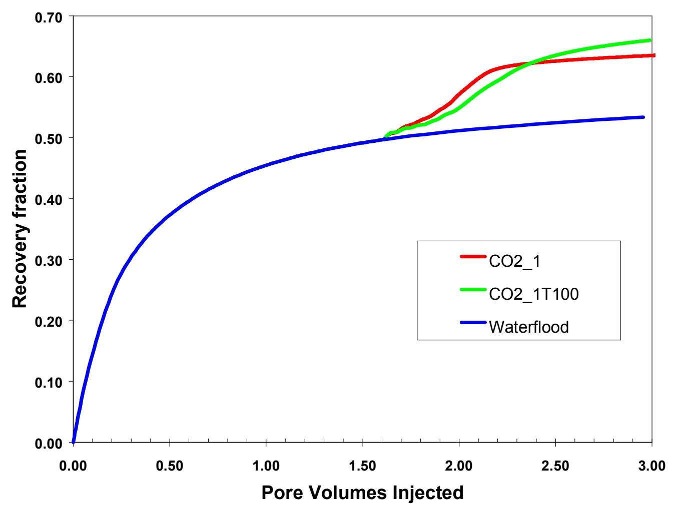

Figure 8: Cumulative production for waterflood and CO_2 WAG

The base case EOS had an MMP of 3950 psi (Oil D previous section). A sensitivity was also considered in which the binary interaction coefficients were adjusted, which resulted in a reduction in MMP to 3150 psi. WAG simulations were run at 6000 psi and 3950 psi (i.e. keeping the pressure above the MMP). During water injection the reservoir will be cooled in the vicinity of the injectors. The temperature distribution will depend on the balance between convective and conductive transport of heat, which is controlled by the reservoir heterogeneity and the waterflood flow regime. To provide a preliminary indication of the effects of different temperatures the base case WAG simulations were run at a reduced temperature of 100^oF. A proper investigation of temperature effects would require running a coupled compositional temperature simulation.

The production data for the water flood is shown in Figure 8. Water breakthrough occurs after approximately 1 year. The watercut rises sharply, reaching a value of 98% at the end of the simulation (all recoveries will be compared at this time). The recovery factor is 53.4% at the end of the simulation.

HIGH PRESSURE INJECTION

A 5 year 1:1 WAG has been modelled (Case CO2_1), with gas and water injection in alternating cycles of 6 months each. The injected gas was pure CO_2 and pressure was maintained at 6000 psi. The total injected gas amounted to approximately 0.35 hydrocarbon pore volumes. The production profile is compared to the waterflood in Figure 8. It can be seen that a small increase in oil rate occurs after approximately 100 days. This is due to the CO_2 moving through the highest permeability layer, mixing with and mobilising the oil. A steady increase in the oil rate occurs shortly afterwards, due to extra production from the other layers. The oil increment is approximately 8.3% of the STOIIP and is recovered with a net gas efficiency of 3.4 Mscf/STB. Approximately 30% of the injected gas remained in the reservoir, Figure 9.

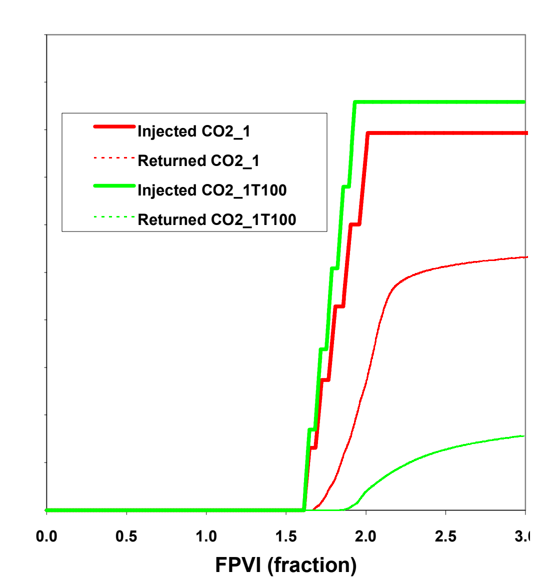

Figure 9: Cumulative injected and returned gas

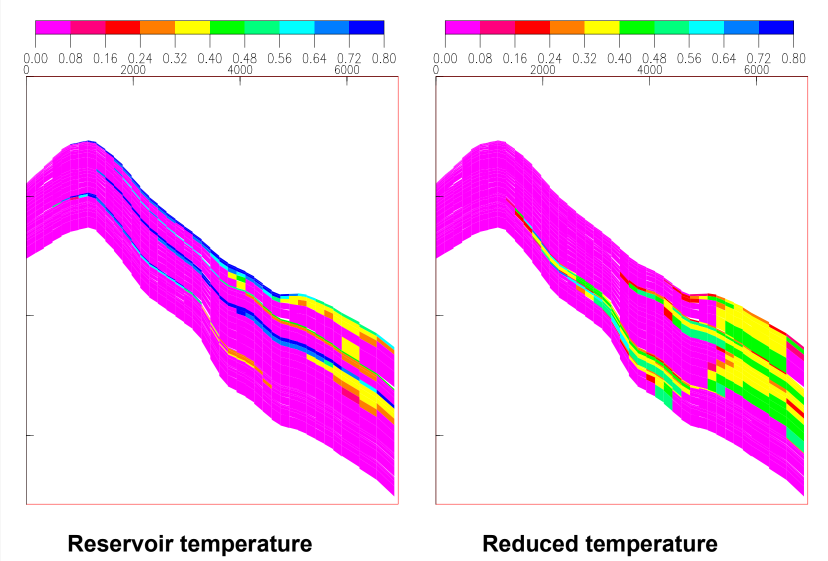

Figure 10: Gas saturation distribution for different reservoir temperature

The same WAG strategy was run with the alternative set of binary interaction coefficients (CO2_1A). Despite the case still being well above the MMP, a lower oil increment of 6.7% STOIIP and a higher GOR after gas breakthrough were found. The net gas utilisation was significantly higher than CO2_1 at 4.1 Mscf/STB.

With the reduced reservoir temperature (Case CO2_1T100) pure CO_2 is denser than both the oil and water phases. The production profiles are shown in Figure 8 and compared to CO2_1. A marked increase in the oil production occurs with the increment rising to 10.9%. Approximately 79% of the injected gas remained in the reservoir. However the net gas utilisation deteriorated to 7.4 Mscf/STB. Gas saturation distributions for this case are compared with the base case in Figure 10. The gas is initially denser than the oil and water so tends to slump slowly towards the bottom of a layer. Consequently, the injected gas contacts a much larger region of oil. As the gas migrates deeper into the reservoir, it mixes with the oil forming a less dense gas phase and a more dense oil phase of about the same density until the mixture becomes single phase. A comparison of the high pressure simulations is given in Table 2.

	IOR (% STOIIP)	Gross gas utilisation (Mscf/STB)	Net gas utilisation (Mscf/stb)
CO2_1	8.32	11.16	3.41
CO2_1A	6.76	13.96	4.10
CO2_1T100	10.85	9.27	7.36

Table 2: Comparison of WAG high pressure simulations

REDUCED PRESSURE INJECTION

The same set of cases were run at a reduced pressure of 3950 psi, which is still at or above the MMP of both EOS models. The results are summarised in Table 3.

	IOR (% STOIIP)	Gross gas utilisation (Mscf/STB)	Net gas utilisation (Mscf/stb)
CO2_2	7.98	9.76	2.35
CO2_2A	7.04	11.16	2.62
CO2_2T100	8.21	12.94	5.36

Table 3: Comparison of WAG simulations performed at the MMP

The results show the same overall trends as the higher pressure injection cases. The incremental recovery for the lower temperature case is significantly reduced, because the injected CO_2 is no longer denser than the injected water. Overall the impact of reduced pressure operation is to improve the gas utilisation efficiency, without significantly affecting the incremental production.

COMPOSITIONAL MODELLING OF CO_2 GSGI

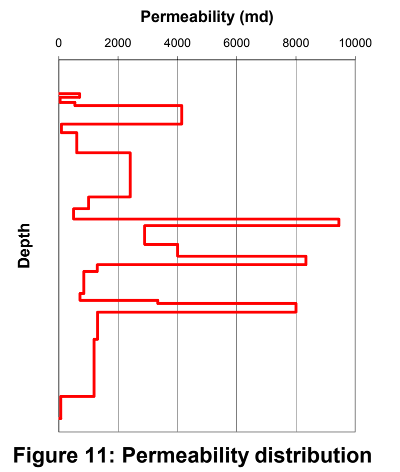

Figure 11: Permeability distribution

Crestal injection of CO_2 in a GSGI mode was studied using a compositional cross-section model of a dipping fault block with the permeability distribution shown in Figure 11, and a grid resolution of 39x1x23 (NXxNYxNZ). The model was waterflooded initially, with the injector completed in blocks (39,1,1-23) and the producer in blocks (1,1,1-23). At the end of the waterflood the recovery factor was 54.9%.

At 1 January 2002, the producer was converted to a gas injector. In practice the oil bank generated by the gas injection would be tracked by redrilling or recompleting the producer as the flood progresses to capture early oil. The focus of this work was to explore the impact of reservoir pressure and compositional effects on recovery, so the production strategy was simplified to a single producer approximately three-quarters of the way down the formation (the original water injector being shut in). This producer was completed over the entire interval, in blocks (31,1,1-23). Production was constrained to give a throughput of one hydrocarbon pore volume over a period of 15 years. The EOS model gave an MMP of 3150 psia. CO_2 was injected into the up-dip well, and in the base case model the reservoir pressure was maintained at 3260 psia.

The oil and gas saturations at 1 January 2017 for the base case CO_2 flood 'CO2_base' are illustrated in Figure 12. A significant fraction of the formation has been swept down to below the ultimate residual oil saturation (Sorg) of 10% defined by the oil to gas relative permeability, due to component transfer, swelling and multi-contact miscibility. There is also a clear oil bank ahead of the gas. At the end of 15 years an additional 21.5% STOIIP has been recovered compared to the waterflood, however it is clear from Figure 12 that more mobile oil could have been produced if the production strategy was being actively managed. The net gas utilisation efficiency is 3.8 Mscf/STB (with a gross gas utilisation of 7.3 Mscf/bbl, indicating that the oil production is achieved within the constraints of reasonable overall gas production volumes).

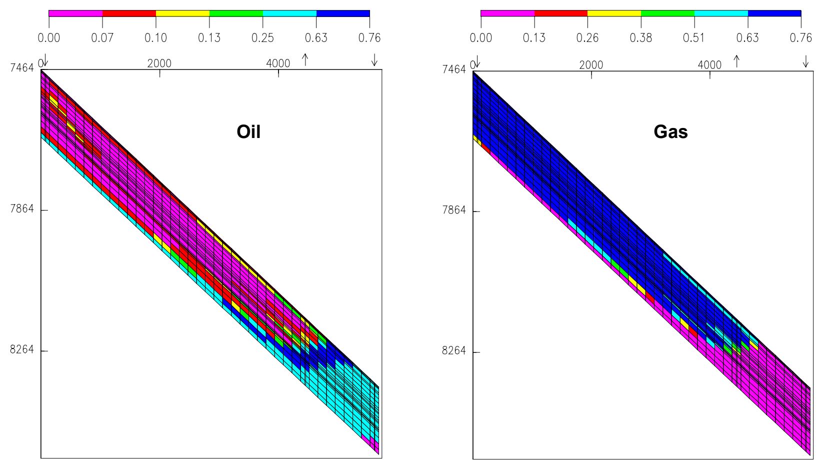

Figure 12: Oil and gas saturation distribution at end of GSGI

To understand the contribution to recovery from compositional effects compared to gravity drainage (as determined by the oil to gas relative permeability), an "immiscible" case (CO2_Immiscible) was run by adjusting the CO_2 /hydrocarbon binary interaction coefficients, to reduce component transfer, and the definition of the gas/oil IFT, to ensure that the immiscible oil to gas relative permeability curve was used. The incremental oil recovery was dramatically reduced from 21.5 to 2% STOIIP, showing that compositional effects are the dominant recovery mechanism. Although the oil saturation was reduced in the region contacted by gas, most of this mobilised oil drained to the bottom of the model, increasing the saturation in the lowest layers rather than being produced.

Cases 'CO2_2000' and 'CO2_2000_Sorg' investigate the impact of reducing the average reservoir pressure to 2000 psi during gas injection (Table 4) to explore the balance between reduced recovery but a reduced net gas injection requirement. The MMP is now 1150 psi above the reservoir pressure. The incremental oil recovery for case 'CO2_2000' is only reduced by 23% compared to the base case, and the final oil saturation is higher in the swept region. However, the net utilisation efficiency has improved by a factor of 2.0, compared to a factor of 1.7 which would be estimated from the ratio of CO_2 densities at reservoir pressures of 3260 and 2000 psi. A comparison of the development of the light and heavy phase densities as the floods progress suggests that the base case is primarily a condensing gas drive, whereas the reduced pressure flood is essentially a vapourising gas drive. Since the displacement is no longer at a pressure above the MMP it is more sensitive to the relative permeabilities and the incremental oil recovery increases by 3.4 MMSTB when Sorg is reduced from 0.1 to 0.0 (cases 'CO2_2000' and 'CO2_2000_Sorg').

These results show that in GSGI applications there may be significant scope to reduce the CO_2 requirement, and therefore the economics, by operating at pressures significantly below the MMP.

Case name	P_{res} during GSGI (psia)	MMP (psia)	S_{org}	Recovery factor (%)	IOR (% STOIIP)	Net gas utilisation (Mscf/ STB)
Waterflood	N/A	N/A	N/A	54.9	-	-
Base case	3260	3150	0.1	76.4	21.5	3.83
Reduced pressure	2000	3150	0.1	71.2	16.3	1.93
CO2_2000_S_{org}	2000	3150	0.0	74.7	19.8	1.60
Immiscible	3260	>>3150	0.1	57.1	2.2	22.71

Table 4: Summary of GSGI simulations

CONCLUSIONS

1. Tertiary CO_2 injection in onshore North American fields is a successful IOR technique that regularly achieves incremental oil recoveries in the range 4-12% STOIIP. Retained gas volumes are typically 10-25% HCPV for tertiary CO_2 floods. The incremental oil production, expressed in reservoir barrels, is generally between 0.5 and 1.0 of the volume retained in the reservoir.

2. CO_2 injection is more complex than hydrocarbon gas injection from a sub-surface standpoint. Up to 5 phases can co-exist in the reservoir. Dissolved CO_2 changes the reservoir chemistry, reducing brine pH, dissolving carbonate minerals, increasing CaCO3 scale in wells and affecting the performance of scale inhibitor treatments.

3. CO_2 is expected to be miscible or nearly miscible with the oil at the current pressures and original temperatures of most UKCS fields. No established guidelines exist for CO_2/hydrocarbon binary interaction coefficients in EoS models of UKCS oils.

4. Although UKCS fields are at higher pressures than onshore CO_2 projects, the higher temperatures compensate to give similar CO_2 densities at reservoir conditions in both UKCS and Permian Basin floods. Consequently, similar quantities of CO_2 would be required to sweep a given reservoir volume in both cases.

5. Compositional simulation of WAG has shown that cooling in waterflooded zones of the reservoir may affect project performance. Significantly more CO_2 is required at the lower temperature because its density increases, but the MMP decreases and the density differences between CO_2 and the oil and water are reduced, or even reversed, which will improve sweep. Gas utilisation can be improved by reducing the operating pressure to near the MMP.

6. Compositional simulation of GSGI shows that gas utilisation can also be improved by operating at reduced pressures, even where these are significantly below the MMP. This underlines the importance of having a well characterised EoS model that allows project performance to be assessed over a range of operating conditions.

ACKNOWLEDGEMENTS
This work was performed as part of the UK Department of Trade and Industry's Sustainable Hydrocarbon Additional Recovery Programme (SHARP) studies at AEA Technology (www.dti-sharp.co.uk). The DTI's permission to publish is gratefully acknowledged.

REFERENCES

1 'EOR Survey'. Oil & gas Journal, 20 March 2000, pg39

2 'Dollarhide Devonian CO_2 flood: project performance review 10 years later', J F R Bellavance, presented at the SPE Permian Basin Oil & Gas Recovery Conference, Midland, TX, 27-29 March 1996

3 'Denver Unit infill drilling and pattern reconfiguration program', B N Thai, C F Hsu, B M Bergersen, S L Albrecht and T W Richardon, SPE 59548, presented at the SPE Permian Basin Oil and Gas Recovery Conference, Midland, Texas, 21-23 March, 2000

4 'Wellman Unit CO_2 flood: reservoir pressure reduction and flooding the water/oil transition zone', D S Schechter, R Grigg, B Guo and B Schneider, SPE 48948, presented at the Ann. Tech. Conf. And Exhib., New Orleans, Louisiana, 27-30 September 1998

5 ' A new analytical method to evaluate, predict, and improve CO_2 flood performance in sandstone reservoirs', S Bou-Mikael, SPE/DOE 35362, presented a the 10th SPE/DOE Symposium on Improved Oil Recovery, Tulsa, OK, 21-24 April, 1996

6 'Goldsmith San Andres Unit CO_2 pilot – Design, implementation and early performance', D E Jasek, J R Frank, L S Mathis and D J Smith, SPE 48945, presented at the SPE Annual Tech. Conf. And Exhib., New Orleans, Louisiana, 27-30 September 1998

7 'North Cross (Devonian) Unit CO_2 flood: status report', G J Mizenko, SPE/DOE 24210, presented at the 8th SPE/DOE Symposium on EOR, Tulsa, OK, 22-24 April, 1992

8 'Reservoir performance of a gravity-stable, vertical CO_2 miscible flood: Wolfcamp Reef Reservoir, Wellman Unit, SPE 22898, SPERE, November 1993, pg 261

9 'A literature analysis of the WAG injectivity abnormalities in the CO_2 process', J D Rogers and R B Grigg, presented at the SPE/DOE IOR Symposium, Tulsa, OK, 3-5 April 2000

10 'Mobility control experience in the Joffre Viking Miscible CO_2 flood', D J Stephenson, A G Graham and R W Luhning, SPE 23598, SPERE August 1993

11 'Review of WAG field experience', R Christensen, E H Stenby and A Skauge, SPE 39883, presented at the International Petroleum Conf. And Exhib. Of Mexico, Mexico, March 3-5 1998

12 'Design and evaluation of a gravity-stable, miscible CO_2-solvent flood, Bay St Elaine field', A J Nute, SPE 11506, presented at the SPE Middle East Oil Technical Conference, Bahrain, March 14-17, 1983

13 'Weeks Island Gravity Stable CO_2 pilot', J R Johnston, SPE/DOE 17351, presented at the SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, OK, April 17-20, 1988.

14 'Production performance of the Wasson Denver Unit CO_2 flood', C S Tanner, P T Baxley, J G Crump III and W C Miller, SPE/DOE 24156, presented at the 8th SPE/DOE Symposium on EOR, Tulsa, OK, 22-24 April, 1992

15 'Slaughter Estate Unit CO_2 flood: comparison between pilot and field-scale performance', M H Stein, D D Frey, R D Walker and G J Parlani, SPE19375, JPT September 1992, pg 1026

16 'Evaluation of CO_2 flood performance: North Coles Levee CO_2 pilot, Kern County, California', D J MacAllister, SPE 15499, JPT, February 1989, pg 185

17 'Update of industry experience with CO_2 injection', R E Hadlow, SPE 24928, presented at the 67th Ann. Tech. Conf. And Exhib., Washington DC, October 4-7 1992

18 'Post-mortem analysis: Lick Creek Meakin Sand Unit immiscible CO_2 waterflood project', PD Moffitt and D R Zornes, SPE 24933, presented at the 67th SPE Annual Tech. Conf. And Exhib., Washington, DC 4-7 October 1992

19 'Understanding and exploiting four-phase flow in low-temperature CO_2 floods', R B Grigg and U W R Siagian, SPE 39790, presented at the SPE Permian Basin Oil & Gas Recovery Conference, Midland, TX, 25-27 March 1998

20 'North Cross (Devonian) Unit CO_2 flood: status report', G J Mizenko, SPE/DOE 24210, presented at the 8th SPE/DOE Symposium on EOR, Tulsa, OK, 22-24 April, 1992

21 'Mineral scale control in a CO_2 flooded oilfield', M Yuan, J Mosley and N Hyer, SPE 65029, presented at the SPE International Symposium on Oilfield Chemistry, Houston, TX, 13-16 February 2001

22 'Selection and application of $BaSO_4$ scale inhibitors for a CO_2 flood, Rangely Weber Sand Unit, Colorado', P J Shuler, E A Freitas and K A Bowker, SPE 18973, SPE Petroleum Engineering, August 1991, pg 259

23 'Management of water alternating gas (WAG) injection projects', N L Sanchez, SPE 53714, presented at the SPE Latin American and Caribbean Petroleum Engineering Conference, Caracas, Venezuela, 21-23 April, 1999

24 'An overview of the North Ward Estes CO_2 flood', J N Ring and D J Smith, SPE 30729, presented at the Annual Tech. Conf. And Exhib., Dallas, TX, 22-25 October, 1995

25 'A case study of the development of the Sundown Slaughter Unit CO_2 flood Hockley County, Texas', L K Folger and S N Ghillot, SPE 35189, presented at the SPE Permian Basin Oil & Gas Recovery Conference, Midland, TX, 27-29 March 1996

26 'Definitive CO_2 flooding response in the SACROC Unit', M V Langston, S F Hoadley and D N Young, SPE/DOE 17321, presented at the EOR Symposium, Tulsa, OK, April 17-20, 1988

27 'Lost Soldier Tensleep CO_2 tertiary project, performance case history, Bairoil, Wyoming, R J Brokmeyer, D C Borling and W T Pierson, SPE 35191, presented at the SPE Permian Basin Oil & Gas Recovery Conference, Midland TX, 27-29 March 1996

28 'Review of CO_2 flood, Springer "A" Sand, NE Purdy Unit, Garvin County, Oklahoma, M J Fox, V N Simlote, K L Stark and L D Brinlee, SPE/DOE 14938, , presented a the 5th SPE/DOE Symposium on EOR, Tulsa, OK, 20-23 April, 1986

29 'Miscible Displacement' SPE monograph, vol. 8, ed. F I Stalkup Jr, 1983, chapter 8

30 'Carbon Dioxide Dynamic Miscibility with Light Reservoir Oils', C Cronquist, Proc. Fourth Annual US DOE Symposium, Tulsa (Aug, 28-30, 1978) **16**

31 ‘CO_2 Minimum Miscibility Pressure: A Correlation for Impure CO_2 Streams and Live Oil Systems’, R B Alston, G P Kokolis, C F James, SPEJ (April 1985) 268-75

32 ‘Generalized Minimum Miscibility Pressure Correlation’, Ø Glasø, SPEJ (December 1985) 927-934