MICROSCOPIC DISPLACEMENT EFFICIENCY
OF ALKANE AND CO2-BASED GASEOUS SOLVENTS
WITH HEAVY OIL

M. Darde, G. Darche

TOTAL EP – CSTJF – Avenue Larribau – 64018 Pau Cedex - France

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ABSTRACT

We present the results of corefloods of various gaseous solvents into cores filled with
extra-heavy oil, performed as part of an integrated approach to design a solvent injection
field test for an unconsolidated sand reservoir containing extra-heavy oils.

This paper first describes the design of the initial solvent composition through
thermodynamic simulations, leading to a C2-C3 mixture as optimal solvent. Then, we
will describe alternative solvent choices, based on the use of CO_2 instead of C2; an
extreme choice of pure CO_2 as solvent will also be evaluated.

Then, we will describe the design and the realisation of 3 coreflood experiments
performed under reservoir conditions, with previously described solvents. Solvents were
injected into 40 cm cores monitored with 1D X-ray. These experiments were matched
with numerical simulations, in an attempt to get relative permeabilities. However, these
matches were not complete, as no experimental PVT full description of the oil-solvent
mixtures were available: this interpretation process still has to be completed.

These experiments showed that this family of solvents provides large microscopic
recoveries, with adequate sweep efficiencies, and observable solvent effects. The way
forward will then be to use the physical parameters derived from the final interpretation
of the experiments to confirm the efficiency of these solvents at field scale.

INTRODUCTION

Production of extra-heavy oils in unconsolidated sand reservoirs is most often performed
with primary processes (natural depletion, CHOPS – "Cold Heavy Oil Production With
Sand") when the oil is mobile enough, like in Canada (Lloydminster and Saskatchewan
regions) or in Venezuela.

Thermal processes, like steam injection, can then be applied, in order to increase
production rates and recovery. However, thermal processes are expensive due to the
intensive use of energy, and due to the large amount of produced water. Therefore,
engineers start considering new processes, in order to replace steam when it is not
necessary, especially in the context of mobile extra-heavy oils.

Typically, injection of gaseous solvent is an alternative to thermal processes for mobile extra-heavy oils. In such a process, a light hydrocarbon mixture is injected, which will mix with the oil at reservoir conditions, thus modifying the nature of the oil (viscosity, also composition, density) in order to make it much more mobile before drainage.

For example, the VAPEX process (Butler, [1]) was designed for Canadian extra-heavy oils, as an alternative to the Steam-Assisted Gravity Drainage (SAGD) process, using the same pattern of horizontal wells, one dedicated to solvent injection, the other one to the production of the diluted heavy oils being drained by gravity.

The VAPEX process was originally studied through 2D scaled models (Butler, [1]; Das, [2]; Cuthiell, [3]), more recently with large 3D models (Yazdani, [4]). These models, equipped with visual cells or monitored through X-ray and CT-scans, helped in better understanding the development of the solvent chamber, therefore aiming at accessing some physical parameters (solvent diffusion, asphaltene deposition...) through the analysis of the geometrical behaviour of the chamber.

We rather performed simpler coreflood experiments, in order to focus on the microscopic behaviour of injected solvent without having to interpret too complex multi-dimensional experiments.

These experiments were performed on 1D cores, using either unconsolidated sands or aerolith as core material, under reservoir conditions with an oil which is initially mobile. Solvents were then selected, in order to be injected as gas phase at experimental pressure and temperature conditions, but with thermodynamic behaviours enabling these solvents to dissolve in large quantities into the oil phase at the experimental conditions.

We first chose a mixture of pure alkanes (ethane and propane), with which we performed a first coreflood. This experiment was interpreted, using an experimental PVT description of the heavy oil - solvent mixture.

We then modified the nature of the solvent, to reduce the amount of required hydrocarbon solvent. We considered the possibility of replacing one alkane by CO_2, supposed to be more available (and possibly cheaper) on the field, typically if a thermal process was applied close to the solvent injection test.

We used a CO_2-propane mixture, again with the objective of injecting a gaseous solvent which would dissolve in large quantities into the heavy oils. Therefore, a second experiment was performed with this CO_2-propane solvent.

A third experiment was then performed with pure CO_2 as injected fluid.

This paper will describe the 3 experiments: experimental setups, observed productions, and interpreted results.

INJECTION OF A C2-C3 MIXTURE

This experiment had already been described in a previous article (Dauba, [5]), but we reinterpreted it, in order to be coherent with the 2 other experiments, using the same simulation methodology.

The heavy oil used in this experiment was a recombination of a stock tank oil with synthetic gas (GOR of 8 sm3/sm3 after flash at standard conditions), with a saturation pressure of 41 bars at 45°C. At these conditions, the viscosity of the oil is 9900 cp.

The operating conditions were chosen around 45°C and 50 bars (state of an undepleted reservoir). The injected solvent was a mixture of 80% ethane ("C2") – 20% propane ("C3"), selected after a series of thermodynamic simulations on different mixtures of C1 to C4 alkanes, in order to maximise the dilution of solvent in the oil phase.

A preliminary PVT experimental study enabled to determine the equation of state describing the heavy oil – solvent mixtures. This study also highlighted the viscosity reduction associated with solvent dissolution, and showed that no asphaltene precipitation was expected at the coreflood operating conditions.

Figure 1 shows a schematic representation of the experimental set-up. It is composed of a core holder set vertically, one pump (top of core) adjusting the injection rate to maintain a constant inlet pressure, sample collectors (at reservoir pressure and temperature conditions) allowing the measurement of solvent and oil productions under reservoir conditions, production pumps (within the sample collectors) operating at a constant velocity to produce fluids out at a constant flow rate. Then, each produced fluid sample is flashed and the production of solvent and oil are also measured at ambient conditions.

The core sample is an unconsolidated sand whose physical properties are described in Table 1; these properties were measured with a constant confinement pressure (100 bars) used in the whole experiment. The solvent flood is carried out by injecting the C2 and C3 mixture determined by the PVT experiments through the top well. The production rate is 3 cc/h at 45°C and the inlet pressure is 50 bars.

The oil and gas (mainly solvent) measured production rates are displayed on Figure 2. The solvent breakthrough time is very early (0.01 PV, or 0.02 OOIP, of injected solvent). After solvent breakthrough, oil continued to flow together with gas, but with an improved mobility ratio due to viscosity reduction (solvent dilution). The experimental recovery was 70% for 2 OOIP injected (Figure 3), with a final recovery of 83%.

In spite of the gravity stabilization of the mechanism, X-ray saturation monitoring showed oscillating gas saturations along the core, without any regular solvent front. We believe the initially very large gas/oil mobility ratio led to viscous fingering of the solvent due to local heterogeneities in the core and to the high injection rate. This instability was not observed in the following experiments, as we reduced a lot the flow rate.

We can notice that we produce a significant amount of gas since the start of the experiment but it does not prevent the oil production. A detailed analysis of the gas produced highlights that it contains a significant amount of C_2 at the breakthrough although no C_2 was initially present in the oil (Figure 4 and Figure 5): light components in the original oil were mainly C_1, also CO_2, C_4 This clearly shows that solvent breakthrough quickly occurred at the producer (bottom of the core).

This early breakthrough was the main difficulty for the history match and the interpretation of the experiment. We could easily match the observed oil production and late gas production rates, using a homogeneous 2D simulation model with properties of Table 1, and adjusting the gas-oil capillary pressure and the gas-oil relative permeabilities. But the early C2 breakthrough was very difficult to match, and simulated gas production was delayed as compared to experimental data.

We then used using a complex PVT formalism. Effectively, with this high withdrawal (and injection) rate, a classical compositional simulation modeled immediate dissolution of solvent into the oil phase, and delayed a lot the breakthrough of C2 in the produced gas. In order to delay this dissolution, and to accelerate the C2 breakthrough, we used a kinetic formalism, through chemical reactions, to slow down the dissolution of C2-C3 in the oil phase (Guillonneau, [6]).

With this formalism, we were able to match the measured production rates (Figure 6). The simulated composition of the produced fluids, though fairly unstable (due to the numerical instability resulting from the complex kinetic formalism which was used), was in the same order of magnitude as the experimental compositions (Figure 7).

In this context of heavy oil, we believe the large amount of injected solvent amplified the impact of the kinetics of dissolution. Therefore, the next experiments will use a much slower flow rate, in order to avoid this non-equilibrium thermodynamic behaviour and possible viscous fingering. We will also use a more homogeneous core material.

INJECTION OF A CO2-C3 MIXTURE
The heavy oil used in this experiment was a recombination of a stock tank oil with synthetic gas (GOR of 11 sm3/sm3 after flash at standard conditions), with a saturation pressure of 46 bars at 48°C. At these conditions, the viscosity of the oil is 2800 cp.

The operating conditions were chosen around 48°C and 47 bars. The injected solvent was a mixture of 62% carbon dioxide ("CO2") – 32% propane ("C3"), selected after a series of thermodynamic simulations on different CO2/C3 proportions, in order to maximise the dilution of solvent in the oil phase at the operating conditions.

The experimental setup was the same as the C2-C3 experiment (Figure 1). The solvent was injected at a constant pressure (47 bars). The reservoir production rate (0.2 cc/h) was

below $1/10^{th}$ of the rate of the 1st experiment, with the expectation that no viscous fingering would occur. In order to observe smooth solvent/oil interfaces, we used a new and more homogeneous core material: the core sample used was a porous ceramic consisting of compacted silicate granules (Aerolith). Homogeneity was controlled by miscible tracing. The coating of the sleeved core was chosen to transmit the radial constraint and finally to avoid any bypass of the gas.

The oil and gas (mainly solvent) measured production totals are displayed on Figure 8. The solvent breakthrough comes rather late (0.9 PV). The final recovery observed at experimental scale was 79% for 1.7 OOIP injected (Figure 9). We effectively got smooth solvent/oil interfaces as desired (Figure 10). The profiles were calibrated to reproduce average core saturation based on produced effluents measured at each batch. This does not yield quantitative saturations (due to the difficulty in evaluating solvent dissolution in oil) but allows us to see the shape of the solvent front.

Analysis of the effluent composition indicates a stripping of methane from the oil until produced gas composition almost reaches injected solvent composition (Figure 11- Figure 12).

We matched experimental production rates (Figure 13-Figure 14) using a theoretical PVT description of the solvent/oil mixture as we haven't yet experimental PVT data with CO2.

We could also fairly match the time of solvent breakthrough, which leads us to think that we don't need non-equilibrium solubility (as opposed to the first experiment). This was possible thanks to the low injection rate (0.2 cc/h). Simulated effluent compositions differ from experimental ones, which suggests that our PVT model has yet to be matched to PVT experiments. Such experimental work is still under design.

The obtained relative permeabilities (match of productions) and capillary pressures (match of the saturation fronts and pressures) are not yet definitive, as we are not yet satisfied with the PVT description of the oil/solvent mixture.

INJECTION OF A PURE CO2 STREAM

The third experiment involved injecting pure CO2 in the same heavy oil as the CO2-C3 experiment (2800 cP; saturation pressure of 46 bars at 48°C). The core was a new Aerolith core, from the same bar as in the 2nd experiment, and whose characteristics are described in Table 3.

Experimental set up was similar to the other experiments. The production rate matched the second experiment's 0.2 cc/h. The experiment was operated at 48°C and 50 bars.

Oil and gas cumulative production are shown on Figure 15, along with cumulative injected CO2. Final recovery after 2.2 pore volumes of CO2 injected is 58% (Figure 16).

Solvent breakthrough at 0.28 PV injected happens rather early compared to CO2-C3 flooding, as pure CO2 is less soluble in heavy oil than a tuned mixture of CO2 and C3: more injected CO2 remains in gas phase within the core, CO2 can migrate more easily through heterogeneities. The gas solvent fronts are still fairly smooth (Figure 17).

The interpretation of this experiment has yet to be done, as PVT experiments are under design. This coreflood shows a potential for large microscopic recovery of heavy oil submitted to CO2 flooding. To assess the field scale attractiveness of pure CO2 injection in heavy oil will require the full interpretation of the PVT and coreflood experiments.

CONCLUSION

This integrated and multi-stage experimental study provided several conclusions about solvent-based (including CO2-based) processes for heavy oil:
1. Alkanes-based or CO2-based solvent injection can lead to very good microscopic recoveries in the context of mobile extra-heavy oils.
2. The injection rate has to be carefully chosen, both to ensure a stable displacement, and also to ensure fast solvent-oil thermodynamic equilibrium.
3. Injection of solvent enabled creation of a diluted oil interface, with reduced viscosities and densities as compared to the original oil.
4. Pure CO2 also showed a solvent effect, leading to large microscopic recoveries, though it was expected to act more as a non-condensable gas in presence of heavy oils.

An accurate PVT model is necessary to be able to interpret the results of these experiments, as solvent flooding implies compositional exchanges and modification of oil properties (viscosity, density...). The necessary PVT experiments have not yet been completed, preventing us from rigorously interpreting all corefloods and getting reliable gas/oil relative permeabilities. The full interpretation still has to be done.

Even if these processes show good microscopic recoveries on homogeneous cores, they will be sensitive to geological heterogeneities in the field, and their efficiency might be degraded by other mechanisms (viscous fingering, channelling...).

Therefore, the final stage of the evaluation of solvent processes should consist in field-scale reservoir simulations with realistic heterogeneous models, using the physical parameters derived from the full interpretation of the corefloods, before considering the possibility of a field test.

ACKNOWLEDGEMENTS

complex experimental work with great care. They also wish to thank G. Hamon and F. Montel for fruitful discussions.

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6. Guillonneau N. and G. Darche (2007): "Complex thermodynamic behaviour to assess the performance of solvent injection into heavy oil", paper presented at the 2007 EAGE-IOR Conference.

TABLES

Table 1 - Physical properties of the porous media used for the C2-C3 solvent flooding

Length (cm)	Area (cm^2)	Porosity (%)	Kg (D)	Kw (D)	Ko(Swi) (D)	Swi (%)
33.8	19.6	33.1	6.7	4.9	6.2	19.6

Table 2 – Physical properties of the porous media used for the CO2-C3 solvent flooding

Length (cm)	Area (cm^2)	Porosity (%)	Ko(Swi) (D)	Swi (%)
33.1	19.6	51.1	2.9	7.2

Table 3 – Physical properties of the porous media used for the CO2 solvent flooding

Length (cm)	Area (cm^2)	Porosity (%)	Ko(Swi) (D)	Swi (%)
32.8	19.6	49.6	2.5	12.3

FIGURES
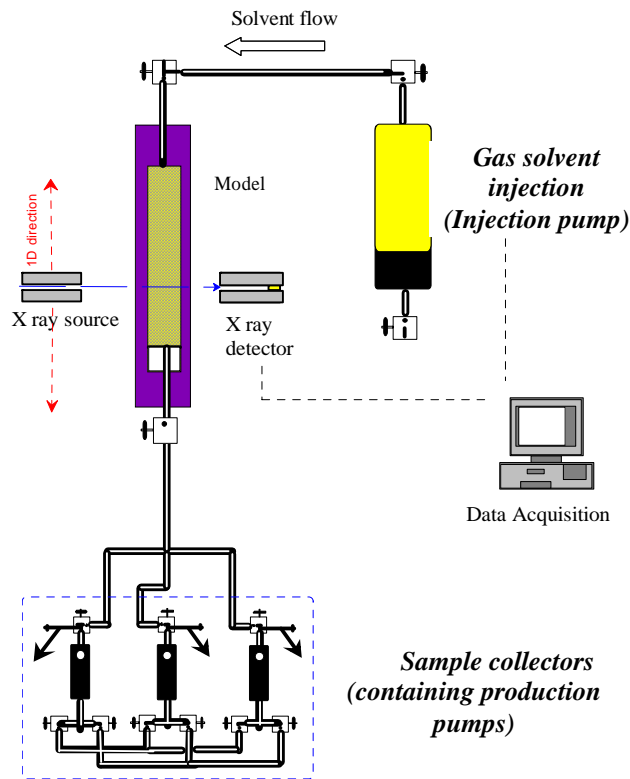
Figure 1 - Experimental set-up for the C2-C3 solvent flooding
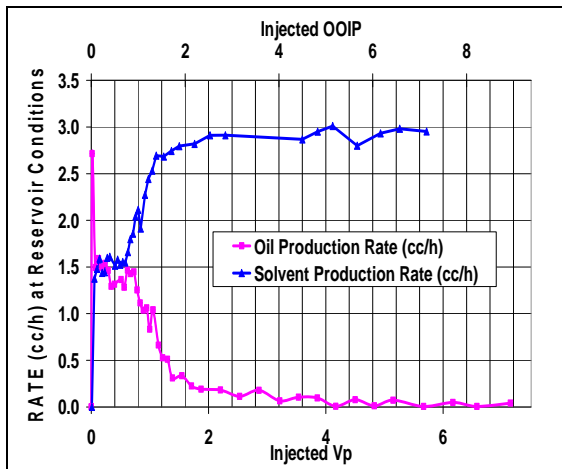
Figure 2 – Experimental production rates - C2-C3 solvent flooding

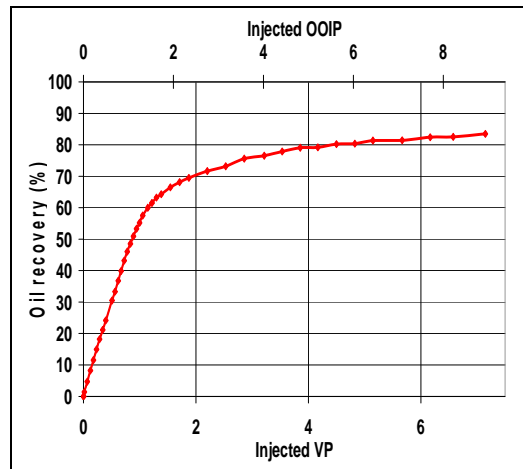**Figure 3 - Experimental recovery - C2-C3 solvent flooding**
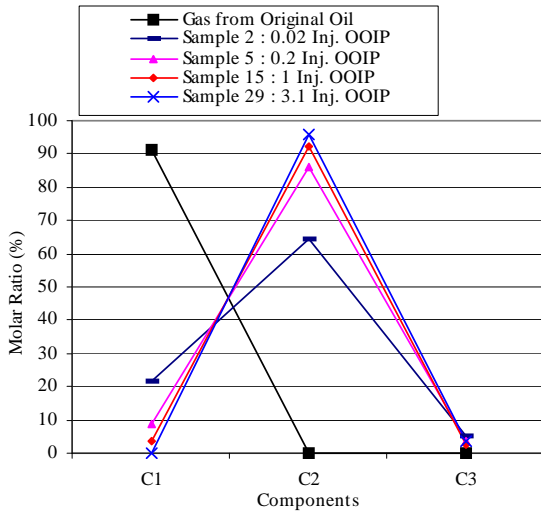
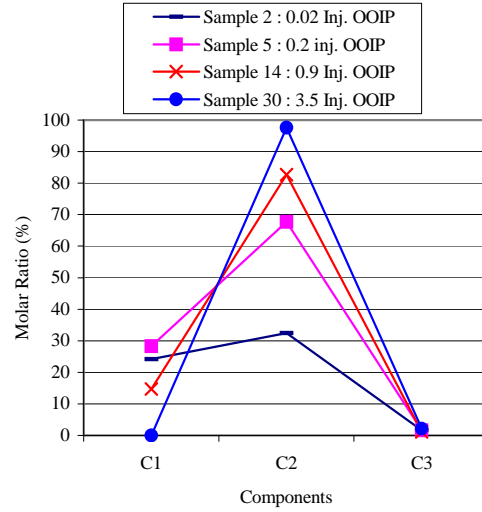**Figure 4 – Composition of gas from produced oil after flash - C2-C3 solvent flooding**

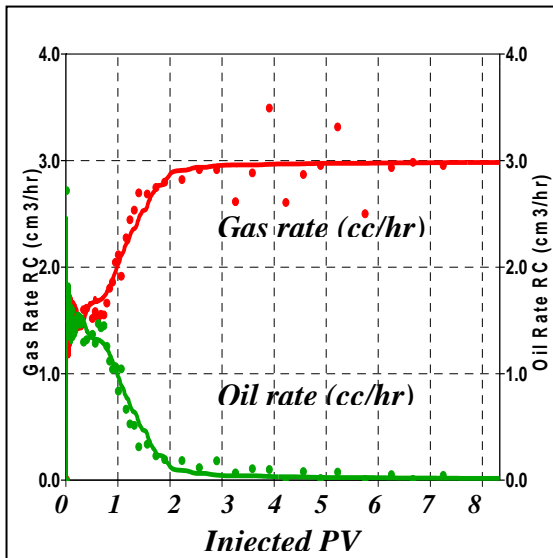**Figure 5 – Composition of produced solvent - C2-C3 solvent flooding**

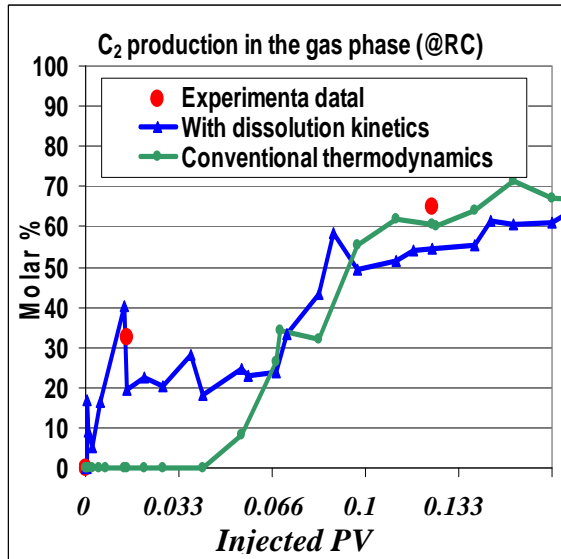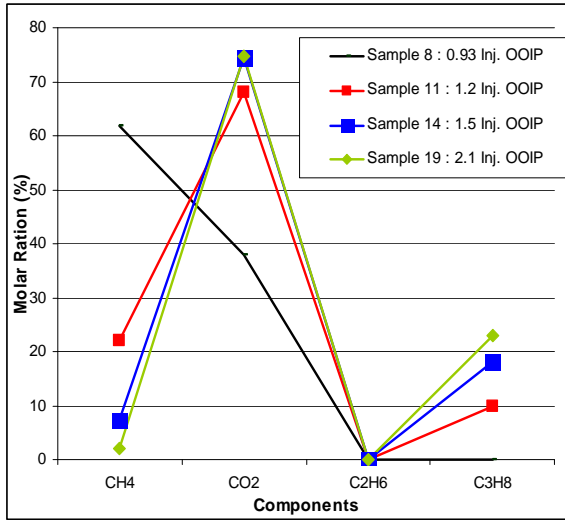
Figure 6 – C2-C3 solvent flooding: Match of the production rates

Figure 7 – C2-C3 solvent flooding: Match of the composition of the produced gas
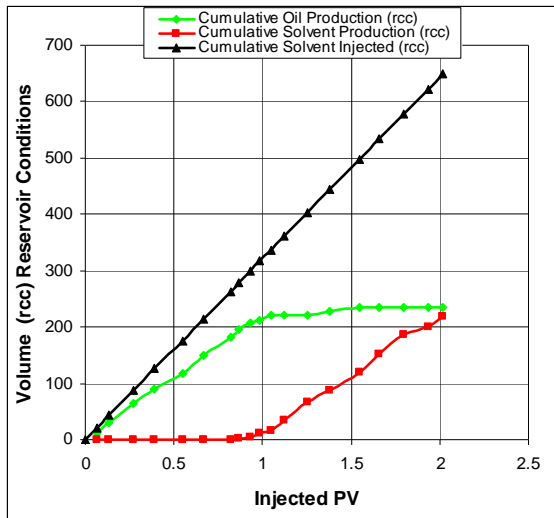
Figure 8 – Solvent injection and oil/gas production - CO2-C3 solvent flooding
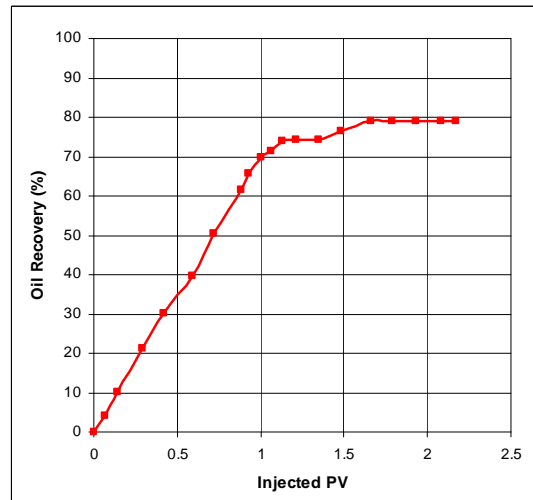
Figure 9 - Experimental recovery - CO2-C3 solvent flooding
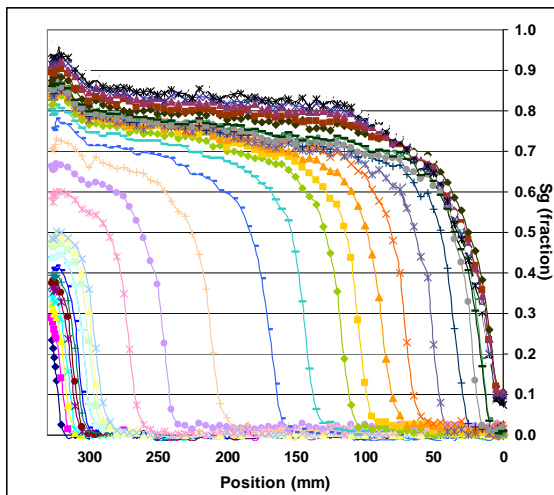
Figure 10 –Gas saturation profiles (injection from the left) - CO2-C3 solvent flooding
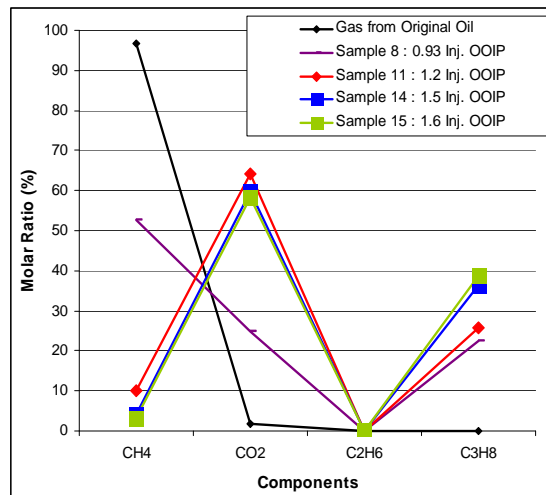
Figure 11 - Composition of gas liberated by produced oil - CO2-C3 solvent flooding

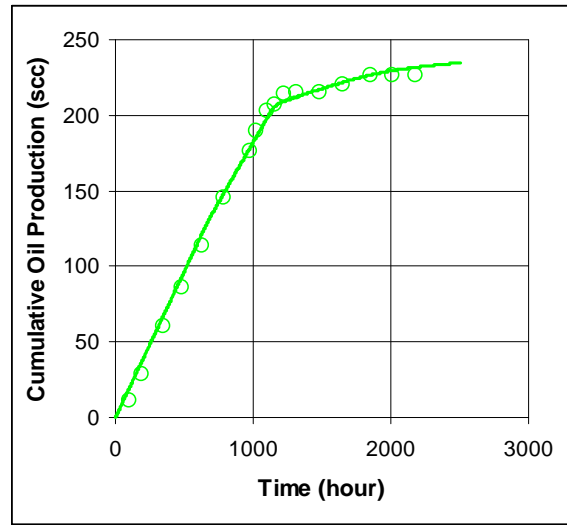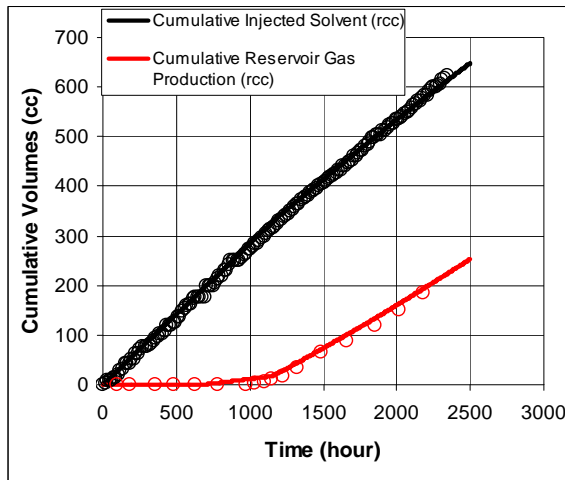**Figure 12 – Composition of produced solvent - CO2-C3 solvent flooding**

Figure 13 – CO2-C3 solvent flooding: Match of the cumulative oil production

Figure 14 – CO2-C3 solvent flooding: Match of the cumulative solvent injected and reservoir gas production
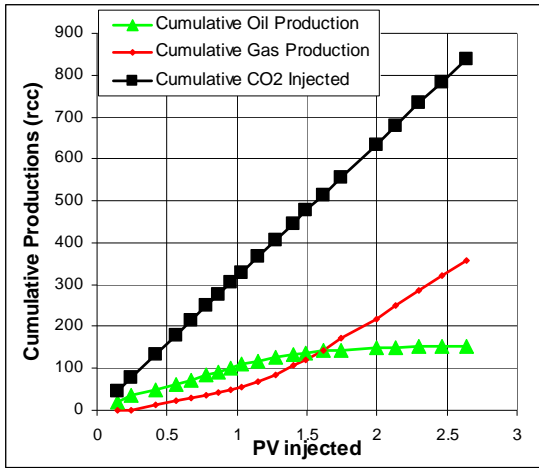
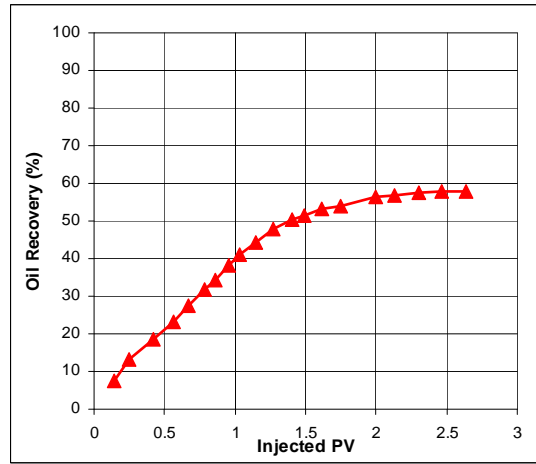**Figure 15 – Solvent injection and oil/gas production - CO2 solvent flooding**

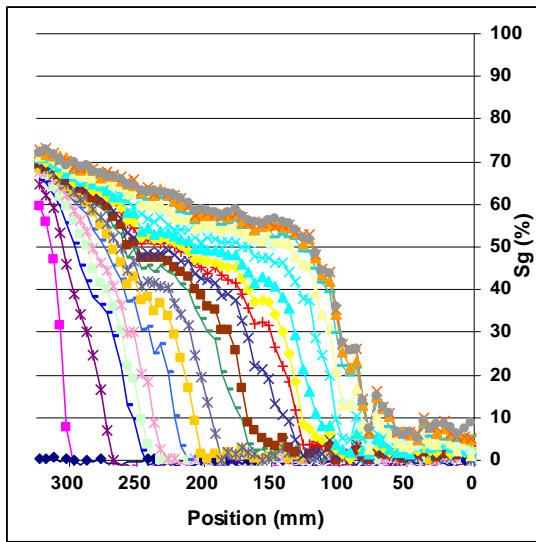**Figure 16 – Experimental recovery - CO2 solvent flooding**

Figure 17 – Gas saturation profiles (injection from the left) - CO2 solvent flooding