GAS PROCESS MISCIBLE DISPLACEMENTS AND ITS IMPACT ON FUTURE OIL RECOVERY SCHEMES IN SUPER GIANT CARBONATE RESERVOIRS

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ABSTRACT
Super giant carbonate reservoirs producing in excess of several hundred thousand barrels of oil per day are a common feature in the Middle East. Many of these reservoirs have been producing for decades, typically with water injection schemes. A challenge is to maintain the plateau production, and where possible enhance the production with additional oil recoveries. Production of additional hydrocarbons using gas process displacements at full or near miscible conditions, including injection of CO2 is now an on-going challenge and the most realistic option. A comprehensive review and analysis is presented on evaluation of tests from several reservoirs, highlighting the impact of in situ wettability and pore geometry.

Carefully designed 1D laboratory tests have been conducted on long composites (typically 60 cm or longer) from a number of different reservoirs with varying trends of intermediate wettability. The tests were designed to represent the full reservoir conditions – temperature, pressure, advance rate and live fluids. Options of WAG, SWAG and continuous injection at both secondary and tertiary (after water floods and/or initial gas injection) conditions were investigated, along with potential impact of wettability. Selected experimental tests were also simulated using compositional simulators to verify the measured outcomes and deviations (if any).

Good miscible gas injection tests allow quick evaluation of expected breakthroughs, final recoveries and potential improvements in carbonates, and thus improved pilot and/or full field design. Impact of wettability is evident from water blocking phenomena in more water-wet reservoirs and almost similar recoveries with respect to the secondary/tertiary/WAG gas injection schemes in more oil-wet reservoirs. Validation of pressure and hydrocarbon production profiles along with respective effluent composition data provides a robust analytical tool to enhance confidence in the different injection schemes and related successes.

INTRODUCTION
Generally, water injection results in a poor microscopic displacement of oil leaving high residual oil saturation, Sor, behind in the form of oil ganglia. It has been reported [1] that on the average, at the end of water flooding, two-thirds of the oil remains entrapped in the reservoir. On the other extreme, plain immiscible gas injection, although proven useful in increasing microscopic sweep efficiency by increasing the Capillary Number (Nc), often results in a low volumetric sweep. This is attributed to the relatively low viscosity of the injected gas resulting in a highly unfavourable mobility ratio (M), which controls the volumetric sweep.

WAG injection process was first proposed by Caudle and Dyes in 1958 [2] and it has served as the petroleum industry default gas mobility control method since then. WAG injection process has several advantages over plain water and gas injection. The higher microscopic displacement efficiency of gas combined with the better macroscopic efficiency of water significantly increases the incremental oil production. Increased oil recovery by WAG is a result of better mobility control, improved frontal stability and more contact with the oil in the un-swept zones. A review [3] of about 60 fields worldwide under WAG injection showed an incremental oil recovery in the range of 5 to 10% of oil initially in place (OIIP). Another review [4] of 14 North Sea fields under WAG injection highlighted a successful WAG in the Statfjord field predicting an incremental oil recovery of 7 to 13%.

Despite the apparent advantages of immiscible WAG (IWAG) injection over plain water and gas injection, it still has the drawback of leaving high residual oil saturation behind the flood front. Review of immiscible core flood tests shows approximately 25-40 % of OIIP that could be potentially left unrecovered after secondary IWAG displacement in most carbonate reservoirs. This represents significant revenue given these super giant reservoirs typically contain multi-billion barrels of OIIP and led to investigating potential EOR processes that can be applied in the subject reservoirs economically to maximize their ultimate recovery. Excellent field application studies have been discussed by Craig et al [5], Stone [6] and Stalkup [7] while Dietz presented an elegant theoretical review [8] of miscible displacement processes.

We reviewed miscible and near miscible gas injection tests performed on 6 different reservoir units of similar formation deposition characteristics, comprising a lower Cretaceous formation. The gas process displacements involved use of rich gas, lean gas and CO2 EOR tests under full reservoir conditions with representative reservoir core composites and reservoir rock types. The objective was to assess the recovery of additional hydrocarbons after secondary water floods and/or IWAG from mature reservoirs, as well as secondary continuous or WAG injections for new developments.

EXPERIMENTAL MEASUREMENTS

Overview of Laboratory Tests. Six sets of gas process displacements are described. Table 1 outlines the basic reservoir core composite parameters, including information on wettability after restoration for a minimum of 3 weeks with respective live reservoir crude. The first 3 reservoir sets of tests (reservoirs A-C) involve hydrocarbon gas injections, with rich gas and lean gas, below minimum miscibility pressure (MMP) and above MMP including WAG/SWAG. The last 3 reservoir sets (tests) involved comparisons with CO2 (reservoir D) and extensive CO2 EOR tests (reservoir E1 and E2). Secondary injection was typically performed after primary drainage and full restoration with live crude for three weeks or more, while tertiary injection generally followed a secondary water flood of 2 PV throughput as common industry practice, unless specified as otherwise.

Each of the core composites were prepared with careful selection of individual plugs using X-ray CT screening and characterization to conform to specific reservoir rock type tested with NMR, MICP and poro-perms. Each core plug was de-saturated using porous plate with in-situ saturation monitoring (ISSM) to target Swi. The detailed procedures for core preparation, handling, characterisation and composite preparation are outlined by Kalam and co-workers [9-

11]. Each core composite was prepared with 1½ inch diameter representative plugs, and was between 50-70 cm long to ensure optimal miscibility with injection fluids. The tests were done at full reservoir conditions with live fluids, and effluent data were collected at regular intervals for subsequent compositional analysis. The bulk of the tests were simulated using a compositional simulator to assess the validity of the individual gas process displacements with respect to hydrocarbon recoveries, respective pressure profiles and the effluent composition at various intervals after breakthrough. Table 1 shows the basic characterization parameters for the 6 selected reservoirs; one composite was used for each of the series of tests described for reservoirs A to E1, while four different composites were prepared to complete the comprehensive data acquisition using CO2 for reservoir E2. Table 2 shows a typical data acquisition format for each test, followed by a summary of different tests on each composite to ensure repeatability and minimize rock type variations – a common problem with carbonates. Figure 1 shows the porosity-permeability range of reservoir core plugs used in the current review.

Rig Description and Flooding Method. Figure 2 is a schematic of the rig set up for each of the gas process displacement tests. The reservoir temperature varied between 250°F to 257°F (125° Celsius) and pore pressure used was 220 to 310.3 barg (4500 psig), depending on the exact reservoir conditions. Two high pressure positive displacement pumps were used (one injecting fluid and other extracting fluids) in order to flood through the core at the required displacement rate. Typically, a laboratory flow rate corresponding to a reservoir advance rate of 1 ft/day was used during each displacement test. For all displacements, the injection rate was kept constant with constant injection pressure. This required the need for small adjustments in the extraction rate to accommodate the changing flood characteristics as the original oil in place was produced. The flood direction during vertical composite orientation was always top to bottom (i.e. gas gravity stable), even when water flooding (secondary water flood and WAG), unless the composite orientation was horizontal. During the immiscible secondary water floods at full reservoir conditions, a long windowed PVT cell contained within the oven was used for volumetric data acquisition. A high pressure sampling station was used to collect fluids during post break-through miscible flooding. These high pressure samples were subsequently analyzed in a PVT laboratory. The facility was equipped with numerous absolute pressure transducers, differential pressure transducers and thermocouples connected to a data logging system.

Core Preparation. The reservoir core plugs were cut from preserved whole cores acquired using non-invasive low invasion water based mud. The plugs were screened using X-ray CT imaging, and characterized using high pressure MICP, thin sections of trims, and poro-perms in cleaned samples. Selected plugs were hot solvent cleaned using a flow through technique and established at 100% brine saturation. Individual plugs were de-saturated to target initial saturation (Swi) with porous plate. Fluid saturations were monitored with ISSM to target the set initial saturation and to ensure local heterogeneity were minimal for each plug used. In addition, pore volume and hydrocarbon pore volume were measured for the assembled composite using ISSM techniques and fluid dispersion measurements. The core composite was aged at full reservoir conditions for a minimum of three weeks prior to core flooding. The reservoir oil was replaced each week with fresh fluid and the effective live oil permeability measured. The final permeability measurement was used as the reference permeability for defining relative permeability.

Secondary Water Flood. Brine was injected at a constant rate representative of reservoir advance rate of 1 to 1.5 ft/day. The oil production rate (pre-breakthrough) was measured for each of the secondary water floods. The oil recoveries at breakthrough and after 2PV brine injection were recorded, and effective brine permeability measured after each flood along with respective production and pressure profiles.

Tertiary Gas Flood. Following the secondary water flood, the hydrocarbon gas injection or CO2 injection test (continuous or WAG, normally with CO2 as first slug) commenced. The gas injection process was a non-equilibrium displacement. Fluid effluent from the core was therefore collected as high pressure samples. Sampling began 8 hours after the commencement of the test. Initial production was captured in the high pressure PVT cell and the initial production rate was measured. Some loss of injectivity was expected since the injection gas would be partially miscible with the reservoir oil at the test conditions. During the flood, high pressure samples were captured and fluid was diverted into the high pressure PVT cell during the sampling outages (required in order to change sample tubes). The high pressure samples were subsequently flashed in a controlled PVT laboratory (including the fluid volume collected in the PVT cell) and the oil productions quantified. The resulting gas and oil from the single stage flash were also analyzed for composition. There was no initial production of oil as brine was first produced. The gas saturation at the flood cessation was calculated (1-Sor-Swr), and the effective gas permeability was measured at this saturation.

Tertiary Hydrocarbon WAG. The test parameters for the WAG experiment were the same as the tertiary gas flood. For the WAG process, an injection volume equivalent to 0.20 – 0.30 PV was used, as applicable to the specific reservoir situation. If starting with 0.25 frac. gas injection followed by 0.25 frac. brine injection, there were four WAG cycles giving a total injection of 2PV (1PV gas and 1PV brine). Following the secondary water flood, hydrocarbon gas injection commenced (0.25 frac. injected). Compositional sampling of effluent from the core started after breakthrough. Initial production was captured in the high pressure PVT cell and the initial production rate was measured. During the flood, high pressure samples were captured and fluid was diverted into the high pressure PVT cell during the sampling outages. The high pressure samples were flashed and the oil productions quantified. The resulting gas and oil from the single stage flash were also analyzed for composition. The gas saturation at the end of the flood saturation was calculated as before for tertiary gas flood.

Tertiary CO2 Flood. Like the tertiary gas flood and the tertiary hydrocarbon WAG flood, tertiary CO2 commenced after secondary water flood. The gas injection process was a non-equilibrium displacement. Fluid effluent from the core was collected as high pressure samples. Sampling began after the commencement of the test (expected initial brine production was captured in the high pressure PVT cell). Major loss of gas injectivity was anticipated since CO2 injection would be partially miscible with the remaining reservoir oil and the reservoir brine. It was also expected that CO2 would be lost due to diffusional processes (e.g. mass transfer to elastomers at the test conditions: O-rings, sleeving materials, seals, annulus fluid etc.). The gas injection and extraction rates were varied, as required, maintaining the test within acceptable pressure tolerances (e.g. 310barg, +/-10barg).

During sampling outages and measurements of permeability (flow via PVT cell) the pump rates were balanced at the selected rates. These pump changes maintained correct system absolute pressure and had only a small impact on the measured differential pressure showing that the pore displacement rate was approximately constant. During the flood, high pressure samples were captured and fluid diverted into the high pressure PVT cell during the sampling outages. The high pressure samples were subsequently flashed in a controlled PVT laboratory and the oil productions quantified. The resulting gas and oil from the single stage flash were also analysed for composition. A summary of the produced oil volumes resulted in a calculated residual oil saturation of 0.005 frac. It is noted that calculation of oil production using this method is optimistic, and the residual oil saturation is most likely to be slightly higher. This is because measured STO volumes are assumed to be of constant composition (density) but visual observation and results from compositional analyses show that the oil fractions post-breakthrough are much lighter in fractions.

Secondary Continuous CO2 Injection and/or CO2 WAG. The tests were identical to above except for displacements being conducted using CO2 in continuous mode or as slugs of CO2 and simulated formation brine at full reservoir conditions. Effluent data were again collected in a high pressure cell for sampling and subsequent analysis.

DICUSSION OF THE RESULTS

Reservoir A. Six sets of gas process displacements are described. Table 1 contains the basic reservoir core composite parameters, including information on wetting characteristics as measured on cores of similar rock type using either Amott Wettability Index or USBM Wettability Indices.

Figure 3 summarises the first set of gas process displacements using rich gas on Reservoir A, comparing secondary gas injection, a tertiary gas injection after a water flood and a SWAG (simultaneous water alternating gas). The tests were performed at 220 bar although the estimated MMP was 257 bar and bubble point pressure was 155 bar. The final oil recovery was high in all the experiments (nearly 90% OOIP at surface conditions), and explicable with respect to wettability being intermediate to oil wet, and hence negligible water blocking effects. In tertiary conditions, the gas injection leads to the production of a large oil bank resulting from the mobilization of the oil trapped after the water flood. The SWAG injection accelerates the oil recovery by a mobility control of the water phase, as detailed by Egermann et al [11]. The repeatability of tests was also confirmed by using two composites of same rock type – secondary gas injections, as shown in figure 3, gave similar profiles.

Reservoir B. Figure 4 shows a comparison of three displacements involving lean gas above MMP – secondary gas flood, secondary WAG and a water flood followed by a tertiary gas flood. The more oil wetting character of this reservoir is evident from the relatively low oil recovery with water injection, similar to Reservoir A. Miscibility was very good, and hence the three gas injection schemes gave similar high recoveries approaching full mobilization of oil in laboratory 1D displacements. The tests confirmed that even in low permeability cases, restored wettability can be captured efficiently, and one can achieve typical intermediate to oil wet scenarios in tight carbonates.

Reservoir C. Figure 5 shows displacements performed with rich hydrocarbon gas above MMP with the least negative wettability index, and hence probably closer to intermediate to water wet reservoir core composite. Compositional simulations validated the experimental data in showing significant water blocking effects, and hence differences in final oil recoveries between secondary gas flood, tertiary gas flood and the two WAG injections with differences in initial gas slug volumes. These four secondary floods are also plotted in figure 6 showing the overall recovery as a function of the fluids injected. The WAG initial gas slug size is 0 for the secondary water flood and 1 for the secondary gas flood. The full experimental details were described by Cable et al [10]. This plot was found to be linear and therefore for this rock type the relationship could be used to estimate oil recovery using larger (or smaller) initial gas slug size. For example, to reproduce the combined water flood and tertiary recovery of 88% HCPV by WAG would require an initial gas slug size of around 0.62 PV. The laboratory results contributed significantly to the full field development options considered.

Reservoir D. This was the first completed systematic laboratory study for development options involving CO_2 injection in both continuous and WAG mode. The results in figure 7 depict the four displacements considered: secondary CO_2 injection as both continuous and as WAG, and tertiary CO_2 WAG displacements following a conventional water flood and secondary lean gas injection below the MMP. The intermediate wet conditions reflected in a high oil recovery of almost 75% with water injection and/or lean gas. It was interesting to note that both continuous CO_2 and CO_2 WAG gave similar high recoveries, above 92%, although one would expect better sweep with CO_2 WAG. The small differences are attributed to experimental artifacts and slight changes to initial oil saturation of the composite after re-saturation to target Swi and full reservoir condition aging in live crude oil. The results also confirmed that, even when tests are done well above MMP, one may still have trapped oil with CO_2 injection, subject to the physical wettability conditions.

Reservoir E1. This study was conducted in parallel to Reservoir D in a different commercial laboratory. The objective was to assess recovery efficiency of continuous CO_2 injection in both secondary and tertiary mode (after conventional water flood). The wettability was expected to be intermediate to oil wet from previous measurements using porous plate and water-oil relative permeability tests. CO_2 tests gave similar recoveries for both secondary and tertiary modes, as shown in figure 8, and were consistent with ultimate recovery found in Reservoir D.

Reservoir E2. This was a comprehensive CO_2 injection study involving four different composites of the same reservoir rock type. The objectives were to ensure similar initial restored wettability at full reservoir conditions, repeatability of the test results and a full suite of five different CO_2 EOR tests. As shown in figure 9, the suite consisted of both secondary and tertiary modes of continuous and CO_2 WAG, and a comparison to rich gas injection above MMP. Full compositional simulation of each of the tests gave robust confirmation of the experimental tests, and there was no evidence of water blocking, again consistent with intermediate to oil wet (wettability) conditions. The process efficiency investigation indicated that recovery efficiency from CO_2 injection is extremely efficient (approximately 98%), irrespective of the injection technique and expected viscous fingering at the low flow rate (reservoir advance rate) deployed.

All five CO_2 injection cases show evidence of significant viscous fingering at the experimental frontal advance rate of ~1 ft/day (i.e. early gas breakthrough and a dispersed oil recovery profile). Viscous fingering was a possibility because the mobility ratio was unfavourable (>6). There were strong grounds for believing that the process tests were affected by viscous fingering. This is particularly true of the secondary continuous CO_2 flood and the secondary WAG floods; however, even the tertiary floods (continuous CO_2 and WAG) appear to be affected. The first line of evidence involves dimensionless analysis of the process test conditions using well-established criteria for viscous stability [12].

Secondary water flood had a negligible effect on the rate of recovery during tertiary CO_2 flood in either continuous or WAG injection modes, confirming findings from other reservoirs. Although rich gas is a slightly poorer solvent than CO_2, the secondary rich gas gave a similar recovery profile to secondary CO_2.

CONCLUSIONS

The following can be concluded from the current findings:

- A comprehensive review of miscible and near miscible gas process displacements in carbonates, covering rich gas above and below the MMP, lean gas at or above MMP and CO_2 in both continuous and WAG injection modes, has been undertaken
- Effect of reservoir wettability clearly established in carbonates despite prevalent mixed wetting characteristics. A less oil wet reservoir shows clear water blocking effects, resulting in different oil recoveries for secondary and tertiary modes, and different WAG ratios.
- CO_2 floods, both continuous and as WAG, are highly efficient in improving recovery efficiency of carbonate reservoirs and can significantly contribute towards reducing carbon footprint.
- Good experimental test design and execution confirm repeatability and reproducibility in carbonate rock types of different reservoirs, despite presence of high local heterogeneity.
- Numerical simulations enhance the confidence of 1D experimental data.
- Ultimate oil recoveries with CO_2 miscible injection, whether as secondary or as tertiary (after water injection) show increases of over 20% when compared with conventional water floods.

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Reservoir	Porosity fraction	Oil permeability keo at Swi, mD	Miscible Injectant(s)	Amott Wettability Index
A	0.31	10.12	Rich gas near/below MMP	-0.50
B	0.21	1.20	Lean gas above MMP	-0.42
C	0.20	1.29	Rich gas above MMP	-0.17
D	0.30	4.64	Lean gas and CO2>MMP	-0.44
E1	0.20	1.33	CO2 secondary/tertiary	-0.51
E2	0.20	1.27	CO2 secondary/tertiary	Not available

*E2 consisted of 4 separate composites each with average porosity of 20% and keo of 1.27 mD.

Table 1 Composite characterization for each study

Comparison of the Secondary and Tertiary Floods

	Secondary Gas Flood	Secondary Water Flood	Tertiary Gas Flood
Initial Oil Saturation, S_{oi} *(PV)*	0.96	0.90	0.25
Gas/Water Injected at Breakthrough *(PV)*	0.87	0.65	0.30
Oil Recovery at BT *(%HCPV)*	85%	68%	0%
Oil Recovery *(%HCPV at cessation of Flood (~ 2PV injection)*	96%	84%	14%
End-point Oil Saturation, *Sor* *(PV)*	0.04	0.25	0.12
k_{rg} (or k_{ow} as appropriate)	1.00	0.27	0.10

Comparison of the WAG Floods

	Secondary WAG I Flood	Secondary WAG II Flood
Initial Oil Saturation, S_{oi} *(PV)*	0.91	0.90
First Gas Slug Size *(PV)*	0.23	0.50
WAG Ratio	1 : 1	2 : 1 first slug only
Gas/Water Injected at Break-through *(PV)*	0.70	0.72
Oil Recovery at BT *(%HCPV)*	66%	75%
Oil Recovery *(%HCPV after at cessation of flood ~ 2PV Injection)*	78%	85%
End-point Saturation, *Sor* *(PV)*	0.20	0.14

Table 2 Typical data collation for each miscible/near miscible injection and summary charts

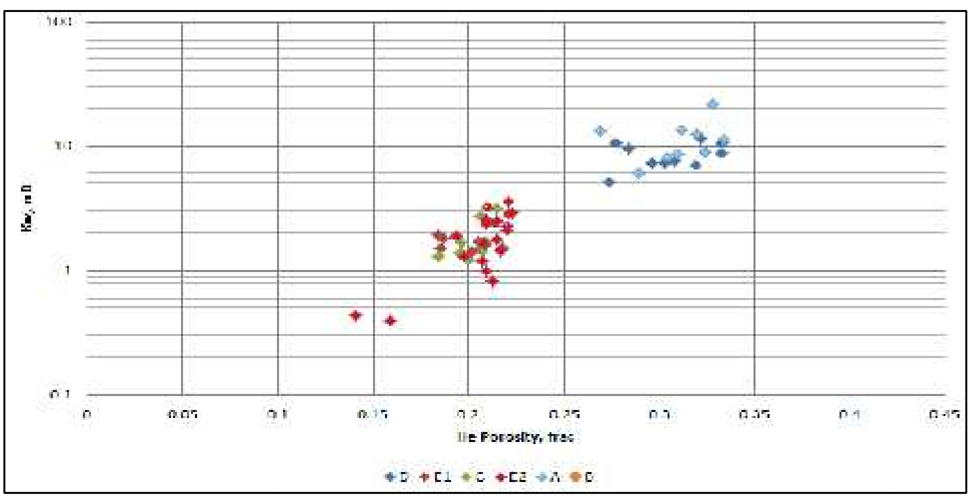

Figure 1 Porosity-permeability ranges of reservoir cores used in the 6 sets

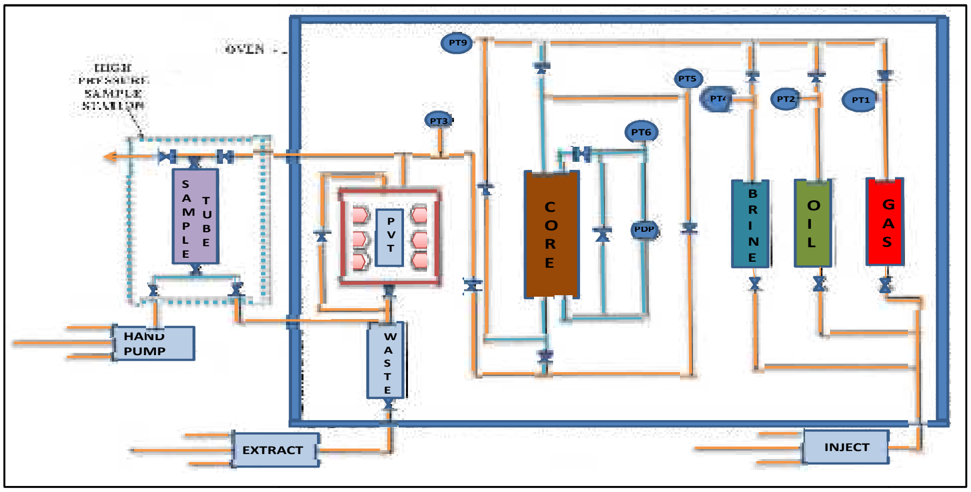

Figure 2 The experimental rig set up for the gas process displacement tests

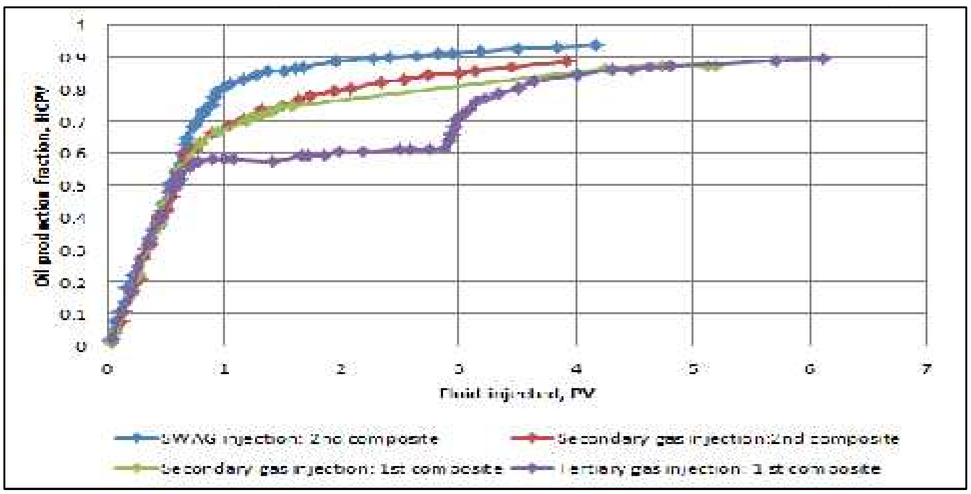

Figure 3 Reservoir A (intermediate to oil wet): rich gas injection tests below the MMP.

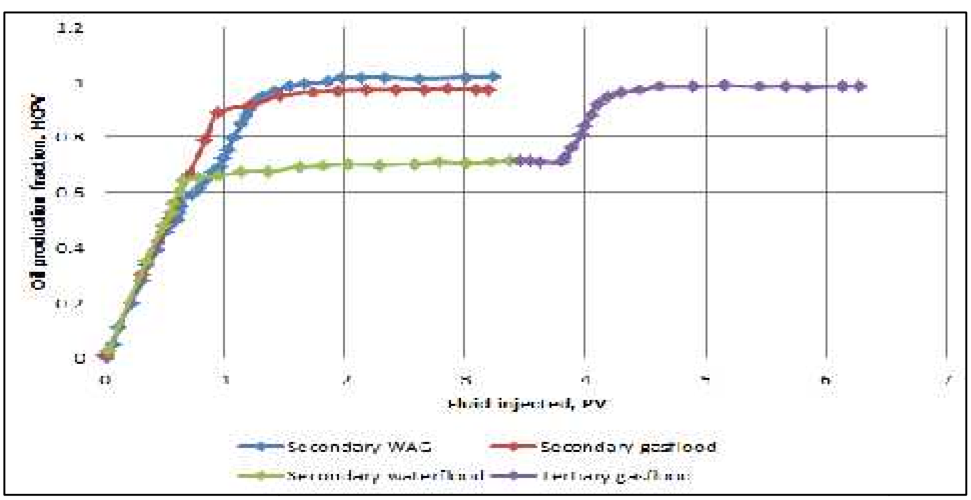

Figure 4 Reservoir B (intermediate to oil wet): lean gas above MMP

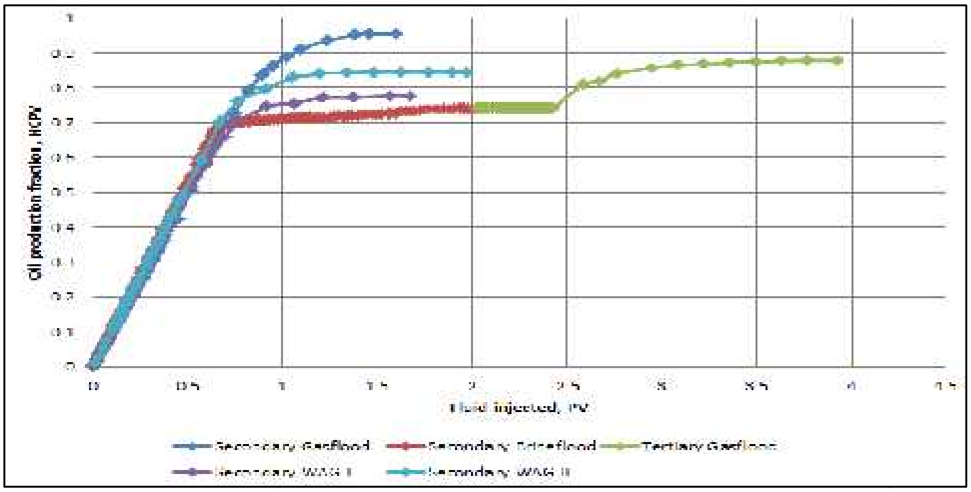

Figure 5 Reservoir C: intermediate to water wet with rich gas above MMP

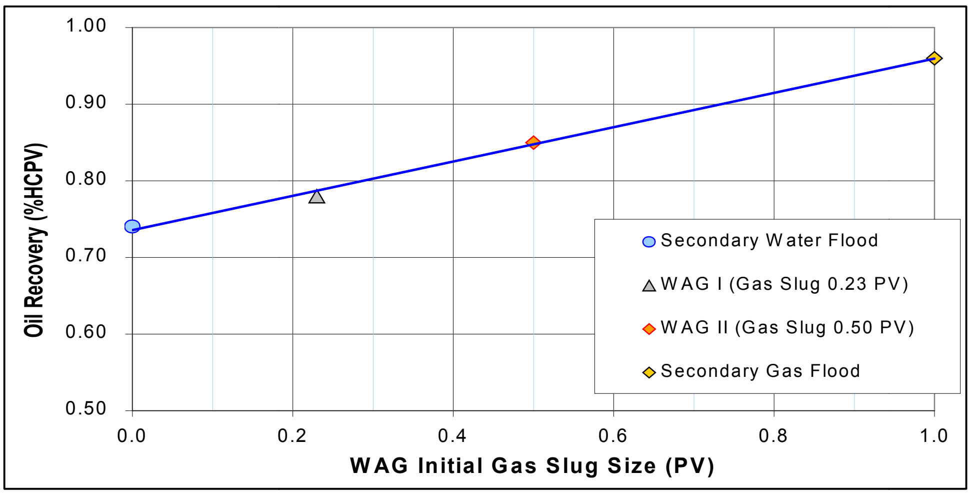

Figure 6 Reservoir C: Oil recovery versus initial gas slug size

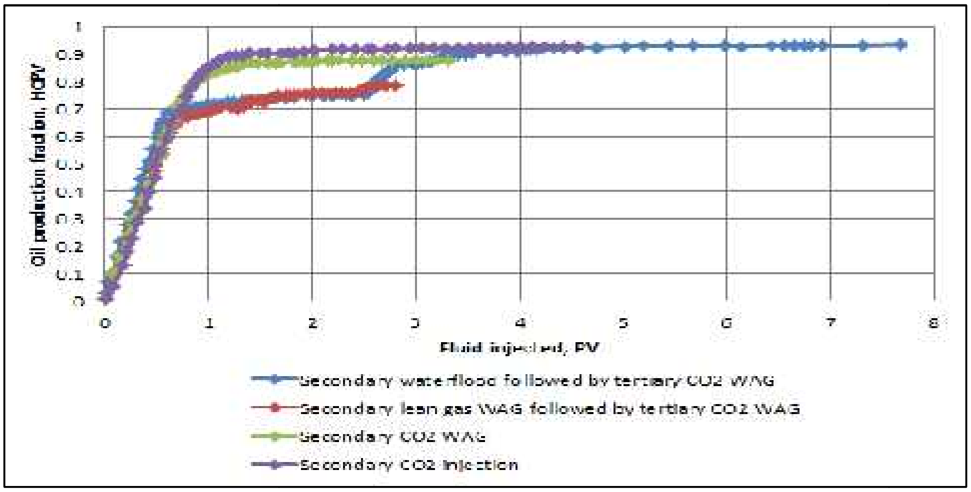

Figure 7 Reservoir D: Intermediate wet - CO2 Continuous & WAG Injections compared with lean gas above MMP

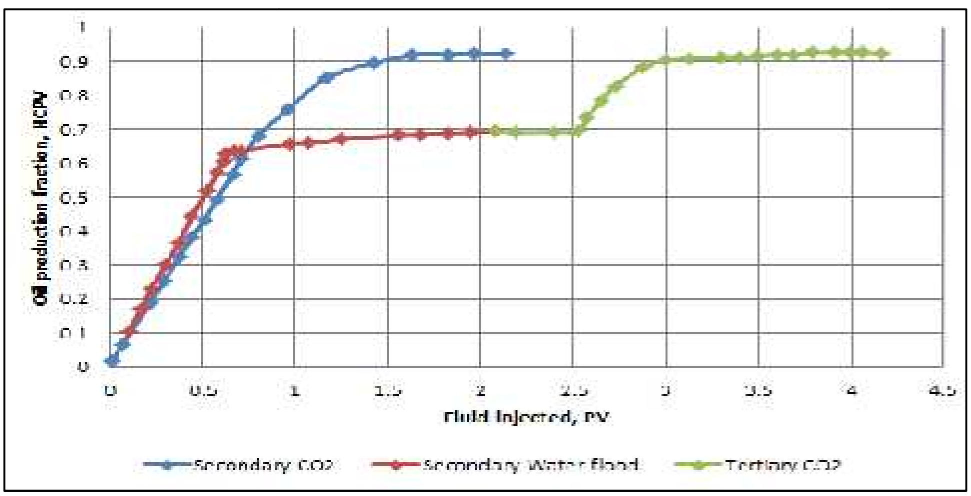

Figure 8 Reservoir E1: intermediate to oil wet - Secondary and Tertiary CO2

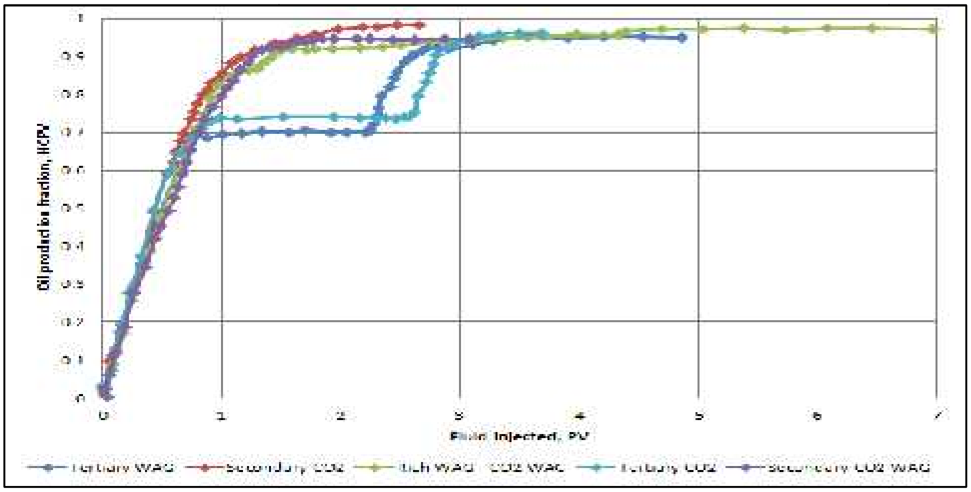

Figure 9 Reservoir E2: intermediate to oil wet – full suite of CO2 EOR tests Continuous CO2 and CO2 WAG in both secondary & tertiary modes and comparisons to rich gas – all above MMP