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Case Study of Heavy-Oil Fluid Characterization for Gas EOR Experiments: Main Challenges

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Abstract

Staatsolie conducted several screening studies in the past decade to explore the potential of enhanced oil recovery (EOR) for its heavy oil (16-17° API) fields in Suriname. The latest study that was performed in 2011, indicated that water and carbon dioxide (CO_2) or water and nitrogen (N_2) injection could be a highly efficient method to extend the life of the fields beyond primary recovery. To validate this conclusion an area of the Tambaredjo heavy oil field was selected for a feasibility study comprising laboratory tests, reservoir simulation studies and ultimately a field pilot trial. This paper presents the results of the laboratory study of the fluid properties of the selected study area. Several oil and gas samples of two wells situated in the study area were collected at the wellhead and at the Multi Phase Flow Meter (MPFM). After quality control, the composition and the physical properties of the samples were determined. Various pairs of oil and gas samples were then recombined based either on assumed bubble point pressure or gas-to-oil ratio (GOR) in an attempt to produce mixtures representing the reservoir fluids. Two recombined samples were subsequently selected based on a comparison with historical data for PVT analysis and swelling study with carbon dioxide and nitrogen. The PVT behavior was found to be qualitatively similar to that of the samples examined in the past except for the viscosity which seems to have increased over a period of ten years of depletion of the reservoir in this part of the field. Most likely this can be attributed to vaporization of the lighter components of the crude oil. CO_2 readily dissolved in the heavy crude oil which led to substantial reductions of oil viscosity while N_2 could hardly be dissolved in the oil. The challenges met during sampling, recombination of the samples and the PVT analyses will be discussed.

Introduction

The Tambaredjo oil field is located in the marshy coastal area of Suriname, 55 km West of Paramaribo. As of May 2014, the average oil production of this field is around 10,800 BOPD from 1,130 production wells. The heavy oil (~ 16-17 API gravity) with a reservoir viscosity varying from 650-1,100 cP, is produced from unconsolidated sands found at depths varying from 900 to 1,400 ft. The sands are of Paleocene age and of fluvial-estuarine to coastal marine of origin.

Since 2003 several screening studies have been conducted by Staatsolie to evaluate enhanced oil recovery (EOR) methods for their heavy oil fields of Suriname. In 2004 a feasibility study for polymer injection was undertaken. The study led to the commissioning of a polymer injection pilot project in a sector of the Tambaredjo field. Polymer injection started on September 2008 heralding the first field trial of EOR technologies in Staatsolie. To further investigate other EOR technologies that could be implemented to increase the reserves base of Staatsolie a more detailed EOR screening study was conducted in 2011. From this study it was concluded that water and carbon dioxide (CO_2) or water and nitrogen (N_2) injection are the most favorable EOR processes for the Tambaredjo oil field from both technical and economic points of view (Moe Soe Let *et al.*, 2012). However, the screening study made predictions relying on a limited amount of PVT data, lack of data on the solubility of the gases in the Tambaredjo reservoir oil and absence of a detailed reservoir characterization. For this reason a feasibility study was initiated in 2012 to investigate water-CO_2 and water-N_2 injection in the Tambaredjo field. The objective was to gather data for the reservoir characterization study that will be used as the basis for the decision whether gas injection is indeed a suitable EOR process. The feasibility study involved laboratory tests and numerical reservoir simulations. Two wells (3I251 and 3D23) in the study area were selected for collecting the oil and gas based on the following criteria: water cut < 30%, GOR > 20% in order to sample sufficient amounts of oil and gas for recombination and PVT analysis. The laboratory program

was comprised of PVT analysis of the Tambaredjo crude oil and core-flood experiments. The PVT analyses included the study of PVT fluid properties and the swelling and viscosity reduction of the Tambaredjo crude oil due to CO_2 and N_2 dissolution. The objectives of this study were to acquire fluid properties of the study area and to determine the solubility of CO_2 and N_2 in the Tambaredjo reservoir oil. As part of the presentation of the results the challenges encountered with sampling of the reservoir fluids, their recombination and PVT analysis will also be highlighted. The core-flood study is reported in a separate paper (Bhoendie *et al.,* 2014). This paper proceeds with a section on the experimental part followed by the discussion of the results and the main conclusions.

Experimental work

Fluid sampling. Bottom-hole sampling is the preferred method for collecting reservoir samples for fluid characterization purposes. This is especially the case when reservoir oil is above the bubble point pressure (P_b) and forms a single hydrocarbon phase at reservoir pressure and temperature. As a result of natural depletion, the reservoir pressure in the study area decreased from the initial value of 480 psi in 2001 to 290 psi as of 2012. Concerns that current down-hole sampling could lead to erroneous fluid properties, including P_b, led to the decision to sample fluids at the surface. For the case study the initial bubble point pressure was unknown, because no down-hole sampling was conducted and gas production rates were not measured from the start of oil production. It was decided to collect the samples at the Multi-Phase Flow Meter (MPFM) rather than at the well head. This was done because the MPFM allows more representative oil and gas samples to be collected while at the same time providing GOR data essential for meaningful PVT analysis acknowledging the limitations of the MPFM (Harper, 2009, Harper, 2011). In September 2012 oil and gas samples were collected from the MPFM connected to the selected wells 3D23 and 3I251. During collection of the oil samples at the MPFM an intermittent flow of liquid was noticed with repeated but short bursts of gas. Since production rates were unstable, additional oil samples were taken at the wellhead and gas samples at the annulus mainly for comparison purposes. **Table 1** gives an overview of the oil and gas samples collected from these wells. The well 3D23 produced oil at higher rates and measurable amounts of gas. The well 3I251 produced oil at lower rates and had immeasurable gas production rates. The amount of gas collected in either case was small, although it was sufficient for the recombination and PVT analysis. The gas and oil samples were shipped to a laboratory in the Netherlands, where the PVT analysis was performed.

Table 1–Oil and gas samples collected from wells 3I251 and 3D23

Type Sample	Well	No of samples	Sampling Point
Oil		5	MPFM oil leg
Oil		1	Wellhead Tubing
Gas	3I251	2	MPFM gas leg
Gas		1	Wellhead Annulus
Oil		3	MPFM oil leg
Oil	3D23	2	Wellhead Tubing
Gas		3	MPFM gas leg

Quality control. The quality control was done upon arrival of the samples at the laboratory. It consisted first of a simple visual inspection of the sampling carrying cylinders to ensure the absence of any leakages or mechanical damage (bent valves, etc.) (Pirlea, 2012). All the samples cylinders were found to be in good order. Then a series of tests were performed to validate the collected oil and gas samples, i.e. to assure that the properties of the samples are consistent. The series of test for validation of the MPFM liquid samples were:

1) Opening pressure and Volume measurement- The cylinders containing the liquid sample were connected at the water end to a high pressure pump and the opening pressure was measured. The amount of water required to bring the samples into single phase at working pressure and temperature was measured. The sample volume (oil + emulsion water) was calculated from the difference between the total bottle volume and the volume of water.

2) Heat treatment- In order to prevent the deposition of waxes and asphaltenes and increase the maneuverability of the samples (i.e. reduce the viscosity), the samples were heated up to a temperature of 2,000 °F while connected to a positive displacement pump. The samples were also pressurized to 4,000 psig and stabilized by shaking for 5 days prior to any removal of samples. A higher pressure was used to increase the maneuverability of the sample as well as improve the gas re-dissolution into the oil.

3) Free water/mud check- The samples were left to settle for a week in an upside down position in an oven for removal of free and emulsified water. Then the subsamples were collected from the top of the sample bottles to check the amount of free water and/or mud content.

4) Compositional analysis- The samples were analyzed using the gas chromatography procedure. Gas chromatography represents the technique where there is a gaseous mobile phase and a liquid or solid stationary phase.

Similar series of tests were performed for the validation of the MPFM gas samples validation. Most of the gas and oil samples were at opening pressures reflecting the sampling conditions. The sample volumes varied between 380 and 650 cm^3 and were sufficient for the subsequent analyses. The amounts of water obtained from the different samples varied from 4 -10 vol.% (**Table 2**). All the oil samples were heavily emulsified with water and involved an extensive water removal process. This will be highlighted later in the paper. The surface and flashed gas samples that were analyzed exhibited very similar properties in terms of compositions, densities and mole weights. Similar results were observed for the flashed dead oil samples, while the composition of the surface 'live' oil samples differed significantly from each other, mainly due to the different gas content in each sample. A few oil samples were measured for viscosity, indicating very viscous fluids. The gas samples from well 3D23 had low H_2S content.

Table 2–Opening conditions and water content from samples of wells 3I251 and 3D23

| Sample number	Well	Opening Pressure (psi)	Opening Temperature (°F)	Sample Volume (cc)	Water Drained (cc)
Oil # 1	3I251	130	64.4	650	40
Oil # 2		73	64.4	650	25
Oil # 3		71	68	600	60
Oil # 4		20	68	570	45
Oil # 5		68	66.2	600	35
Oil # 6		70	66.2	480	30
Gas # 1		15	68	20000	0
Gas # 2		15	68	20000	0
Gas # 3		90	68	20000	0
Oil # 7	3D23	90	69.8	540	45
Oil # 8		80	69.8	525	30
Oil # 9		60	66.2	380	15
Oil # 10		52	66.2	525	30
Oil # 11		70	68	540	45
Gas # 4		100	68	20000	0
Gas # 5		55	68	20000	0
Gas # 6		55	68	20000	0

Physical property analyses. The physical properties of both oil samples from wells 3I251 and 3D23 were measured (Pirlea, 2013a). The API gravity was measured in the laboratory by digital vibrating U tube densitometer, while the molar mass was estimated by a cryoscopy technique. Viscosity measurements were done on the flashed samples using Electromagnetic viscometer (EMV). To obtain a more accurate value at reservoir temperature (37.5°C) three viscosity readings were taken at 35, 40 and 45°C. The technique that was used for SARA analysis was Iatroscan^{TM} Thin Layer Chromatography with Flame Ionization Detection (TLC-FID). The simulated distillation method was used to characterize petroleum fractions and products by quickly determining their boiling range distribution. Samples are analyzed in a chromatographic column that separates the hydrocarbons in order of their boiling points.

Samples recombination. Before conducting the physical recombination a mathematical recombination was performed on a molar basis in an attempt to reproduce the composition of the original reservoir fluid using MPFM GOR values from longer duration MPFM tests (performed after sampling on selected wells). The recombined composition was computed for five (5) gas and oil pairs of samples (Pirlea, 2013a) (**Table 3**).

Table 3–Mathematically recombined pairs of oil and gas samples from well 3D23 and well 3I251

Pair	Type Sample	Sample number	Well	Date	Sampling Point	GOR (scf/d)
1	Oil	Oil # 1	3I251	9/11/2012	MPFM oil leg @ testing loc	0.83
1	Gas	Gas # 1	3I251	9/11/2012	MPFM gas leg @ testing loc	0.83
2	Oil	Oil # 6	3I251	9/13/2012	Wellhead Tubing	0.33
2	Gas	Gas # 3	3I251	9/13/2012	Wellhead Annulus	0.33
3	Oil	Oil # 9	3D23	9/13/2012	MPFM oil leg @ testing loc	30.58
3	Gas	Gas # 4	3D23	9/13/2012	MPFM gas leg @ testing loc	30.58
4	Oil	Oil # 10	3D23	9/14/2012	MPFM oil leg @ testing loc	30.58
4	Gas	Gas # 5	3D23	9/14/2012	MPFM gas leg @ testing loc	30.58
5	Oil	Oil # 11	3D23	9/14/2012	MPFM oil leg @ testing loc	30.58
5	Gas	Gas # 6	3D23	9/14/2012	MPFM gas leg @ testing loc	30.58

The compositions of the recombined pairs of oil and gas samples of well 3I251 and 3D23 are exhibited in **Fig. 1.**
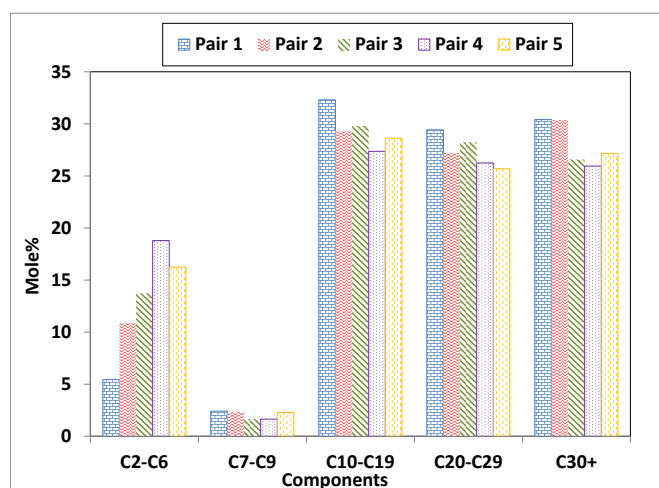
Fig. 1–Compositions of recombined pairs of oil and gas samples

The compositions of the lighter components (C2-C6) of the recombined reservoir fluids varied widely, mainly due to the varying composition of the surface liquid samples collected (i.e. varying gas content) and the recombination ratios used. The recombination ratios used are not equal to the GOR of the recombined sample, which is higher because the oil samples used to calculate the recombined compositions were not 'dead' but 'live' i.e. the samples still contained gas. The GOR of the collected liquid samples varied from 16-43 scf/bbl (well 3I251) and from 25-76 scf/bbl (well 3D23). The results of the mathematical recombination confirmed that the samples have varying 'live' oil compositions and fluctuating GOR during sampling. This indicated that using the measured GOR's to physically recombine the samples would likely lead to a misrepresentation of the reservoir fluid.

The initial intention for this study was to recombine samples taken at the MPFM to the measured GOR. Historical PVT analyses within the Tambaredjo field have only been conducted on wellhead samples that were recombined to either an average expected GOR or a P_b equal to the reservoir pressure, since the P_b was never accurately determined. Although different recombination methods were used for the historical PVT analysis, a relationship was observed between the bubble point pressure and the GOR (**Fig. 2**). Due to the varying GOR measurements recombination to the measured GOR's would likely yield in inaccurate reservoir fluid properties hence the decision was taken to recombine two pairs to compare the results with the historical PVT data. It was decided to recombine two pairs to an average expected GOR and compare the results with the historical PVT data. An estimation of the P_b and viscosity of these two recombined pairs would quickly indicate if there are major differences with historical PVT data for further decision making on the actual physical recombination method. The

recombination was done as follows: (1) pair 1 (well 3I251) was recombined to a GOR of 1 scf/bbl (the 'live' oil sample had a solution GOR of 20 scf/bbl) and (2) pair 5 (well 3D23) was recombined to a GOR of 31 scf/bbl (the 'live' oil sample had a solution GOR of 39 scf/bbl). The samples were stabilized at a working pressure of 4,000 psi and a temperature of 40.5°C. The working pressure and temperature were selected for maneuverability and ease of stabilization purposes. The occurrence of the bubble point was visually determined through the cell window and from the change in the slope of the relative volume versus pressure curve. The observed bubble points (at 40.5°C) were 150 psi for pair 1 and 520 psi for pair 5. The results of both pairs were not within the range of the historical PVT data (**Fig. 2**).
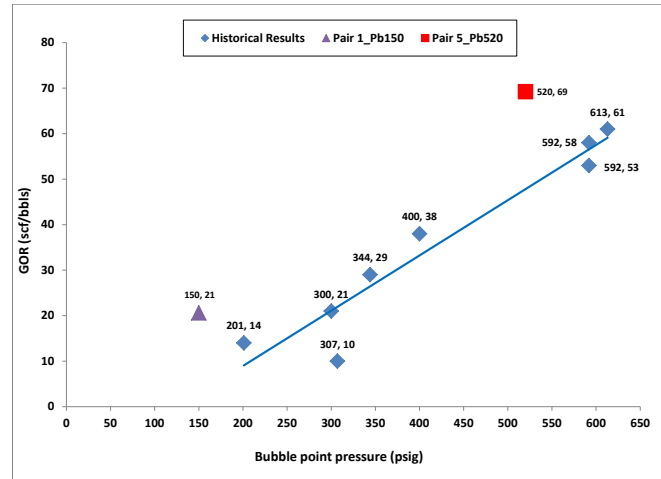

Fig. 2— Bubble point pressure vs. GOR from historical data and recombined pairs

Based on above results it was decided to recombine to a bubble point pressure because this seemed a more reasonable method than recombining to a GOR. Recently available downhole temperature data confirmed the reservoir temperature to be at 37.5°C instead of the previously used 40.5°C. For all subsequent analysis a reservoir temperature of 37.5°C will be used. Pair 1 (well 3I251) was selected to be recombined at a bubble point of 290 psi (current reservoir pressure) and 480 psi (initial reservoir pressure). Recombining to a higher bubble point pressure would result in a complete range of bubble point versus solution GOR behavior.

PVT analyses. Gas was added through trial and error to the oil sample (Pirlea, 2013b). The bubble point measurements were performed subsequently until the value was close to the bubble point pressure. The occurrence of the bubble point was visually noticed through the cell window and from the change in the slope of the relative volume versus pressure curve of the Constant Composition Expansion (CCE). To measure the viscosity the fluid was charged to an EMV measurement chamber and then depressurized stepwise. At stages above bubble point, the liquid was charged in single phase from the PVT cell to the EMV. For the CCE a known amount of the recombined sample was expanded in the PVT cell from the working pressure to a temperature of 37.5°C. The samples volumes were measured at each step. The data generated from the experiment were: bubble point pressure, relative volumes, compressibility and Y factor.

The Differential Vaporization (DV) tests were done using the same recombined sample as for the CCE. The DV analysis simulates the volumetric and compositional changes in the reservoir during production. The fluid was charged to a cell at reservoir conditions then expanded stepwise down to atmospheric conditions, with the gas liberated at every step. The use of the PVT cell and the embedded camera allowed the operator to visually control the displacement of the gas. Due to the very limited amount of gas, the stages were chosen as follows: bubble point pressure, 200, 150, 100, 50 and 0 psi. Gas volumes, compositions and liquid volumes were measured at each step. The oil remaining at reservoir temperature and 0 psig was the residual oil. The ambient residual oil properties (mole weight, density and composition) were measured. The final data included: GOR, Relative Oil Volume, FVF, gas gravity, gas compressibility factor and liquid density.

The separator test was only conducted on recombined pair 1 (**Table 3**) to a P_b of 480 psi. The sample at bubble point pressure was flashed from a PVT cell at saturation conditions into a separator unit. Once the sample was stable, the gas was removed from the cell. The gas volume, liquid volume remaining in the cell, cell and ambient temperatures and pressures were recorded. The gas composition was measured. The process was repeated at the conditions of the subsequent stages. The last stage was undertaken at stock tank conditions and the residue composition was measured. The resulting data included gas volume at Pstage and Tstage, gas volume at standard conditions, separator solution gas oil ratio and relative oil volume at Pstage and Tstage.

Swelling tests. The swelling test was conducted to investigate how the fluid behaves in case of gas injection (CO_2 and N_2). The swelling experiment comprised of: (a) swelling with CO_2 in 'live' oil (480 psi), (b) swelling with CO_2 in 'dead' oil and (c) swelling with N_2 in 'dead' oil. The swelling with CO_2 was conducted as follows: (1) The PVT cell was charged with either the recombined 'live' oil sample (adjusted to a bubble point of 480 psi at 37.5^0C) or dead oil of well 3I251 (Pirlea, 2013c). An amount of CO_2 corresponding to a 15% molar ratio to the liquid was thoroughly mixed with the recombined sample until completely dissolved. The volume of the swollen fluid was recorded. Hereafter a CCE was conducted which entailed expanding the sample containing the 15% CO_2 dissolved from the working pressure of 6,000 psi to the bubble point pressure at a temperature of 37.5^0C. The volume variation with pressure was measured, as well as the bubble point pressure (visually). Oil density at pressure 'n' was measured by pumping a known amount of 'live' fluid into a cylinder and then weighing it. The data generated from the experiment were swelling factor, bubble points at each stage, relative volume, compressibility, 'live' density and 'live' viscosity. This procedure was repeated adding increments of 15% mole CO_2 i.e. 30%, 45% and 60%.

The swelling factor (relative volume) was calculated using the following Equation 1:

$$x_S = \frac{\text{Vsat n\% gas}}{\text{Vsat orig}}$$

$$\text{Eq. 1}$$

where Xs is the swelling factor, Vsat n% gas is the Swollen Volume at P_b and 37.5^0C for n% gas and Vsat orig = Volume of Initial Fluid at P_b and 37.5^0C.

The 'live' viscosity measurement on the swollen sample with CO_2 was also conducted at 37.5^0C. The 15% CO_2 (and subsequently 30%, 45% and 60%) gasified fluid was charged to an EMV measurement chamber and then depressurized stepwise.

For the swelling with N_2 in 'dead' oil the PVT cell was charged with demulsified 'dead' oil from well 3I251 (Pirlea, 2013d). The swelling test for nitrogen contained the similar procedure as for the CO_2 swelling test. Great difficulty was encountered dissolving 15% mole N_2, with the pressure reaching the limit of the PVT cell. Hence it was decided to proceed with lower mole % of N_2. Even at 10% mole N_2 and 7% mole N_2 similar difficulties were encountered. The tests were continued with smaller concentrations as low as 1, 2 and 5% mole N_2 which were successful in dissolving the nitrogen in the oil. The same parameters that were determined were swelling factor, bubble points at each stage, relative volume, compressibility, 'live' density and 'live' viscosity. Due to difficulties in dissolving N_2 in 'dead' oil, the swelling test with N_2 in 'live' oil was abandoned.

Results and discussion
Typical black oil physical properties were measured for the samples to be used for the distribution of oil properties throughout the reservoir model. These properties include but are not limited to API gravity, 'dead' oil viscosity at different temperatures, molecular weight, SARA analysis, simulated distillation analysis and compositional analysis (gas and oil). The compositions included individual components up to tridecane and the lumped properties of the tridecane plus components. Pair 1 (well 3I251) was selected to be recombined to different bubble point pressures for reproducing the reservoir fluid and conducting a black-oil PVT analysis. 'Live' and 'dead' oil samples were to be mixed separately with CO_2 and N_2 to analyze the oil swelling factors, GOR, 'live' viscosities and 'live' densities. The black oil, CO_2 and N_2 PVT data was used for an equation of state model of the oil suitable for use in a compositional simulator.

Physical properties. The measured physical properties are presented in **Table 4**. The crude oils analyzed exhibited values of API gravity between 15.15 and 16.22, mole weights between 343.79 and 350.30 g/mol, atmospheric density of 0.96 g/cc and an atmospheric viscosity between 1,470 and 1,736 cP at 35°C. At relatively small temperature differences, atmospheric oil viscosities showed wide variations (**Fig.3**). These results mark the high sensitivity of the oil viscosity to small temperature changes of this Tambaredjo crude. The lower temperature also caused delay in the PVT analysis due to unusually long equilibration times of the samples.

Table 4–Physical properties of oil samples from wells 3I251 and 3D23

	Location	API Gravity	Mole Weight	Atmospheric Density	Atmospheric Pressure Dynamic Viscosity		
		(^{0}API)	(g/mol)	(g/cc)	(cP) at 35^{0}C	(cP) at 40.5^{0}C	(cP) at 45^{0}C
Well 3I251							
Oil Sample 1	MPFM	15.44	346.04	0.96	1635	1005	666.9
Oil Sample 2	MPFM	15.58	349.2	0.96	1632	998	674.3
Oil Sample 3	MPFM	15.44	348.55	0.96	1610	958.4	625
Oil Sample 4	MPFM	15.67	349.99	0.96	1522	975.4	635.5
Oil Sample 5	MPFM	15.23	348.11	0.96	1470	881.4	592.5
Oil Sample 6	Wellhead	15.29	349.93	0.96	1736	973.5	660
Dead Oil Sample 1	Wellhead	15.25	350.3	0.96			
Well 3D23							
Oil Sample 7	Wellhead	15.59	348.05	0.96	1479	937.6	652
Oil Sample 8	Wellhead	16.21	344.32	0.96	1535	947.4	620
Oil Sample 9	MPFM	15.15	349.83	0.96	1539	960.3	659
Oil Sample 10	MPFM	15.58	346.65	0.96	1505	901.3	620
Oil Sample 11	MPFM	16.22	343.79	0.96	1490	923.2	625
Dead Oil Sample 2	Wellhead	15.46	348.87	0.96			
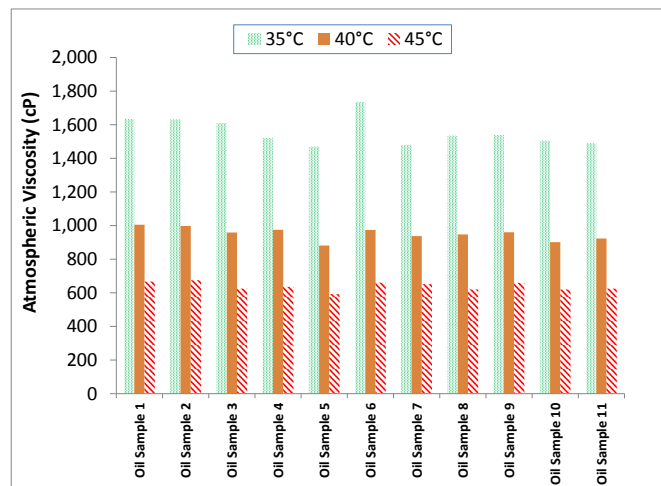
Fig. 3 – 'Dead' Oil (emulsified) viscosity at various temperatures

SARA analysis. The results of the SARA analyses are shown in **Fig. 4**. The measured properties are typical for medium-heavy and viscous oils. The asphaltene-resin component was significant high, approximately 20 to 40%, leading to a tendency to form strong emulsions. The boiling point distribution ranges were typical for medium-heavy oil. Smaller recoveries were found at lower boiling points for the 'dead' oils as opposed to flashed oils, due to the difference in the flashing process in the laboratory and the separation in the well. Although later additional water was found in the oil samples, density and mole weight measurements were less likely to contain entrained water since they were taken after a long de-emulsification process and always from the top of the sample.
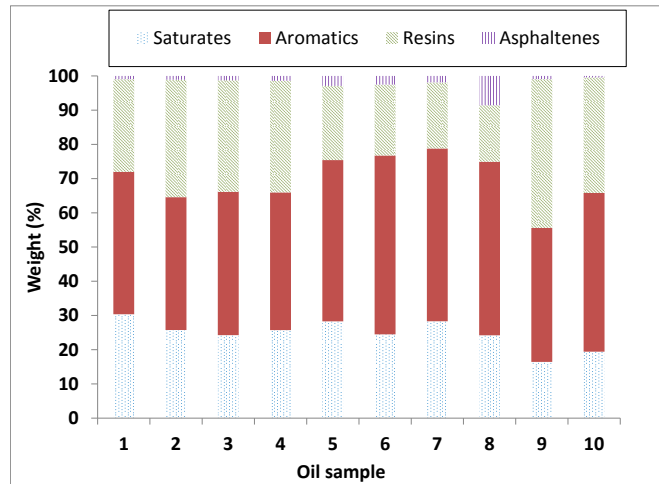
Fig. 4─SARA Analysis results

PVT analyses. The results of PVT analysis 1 and 2 are depicted in **Fig. 5 and 6**. The data generated from the CCE were bubble point pressure, relative oil volumes, compressibility and 'live' density. **Fig. 5** presents the relative volumes and isotherm compressibility coefficient of the oil samples.
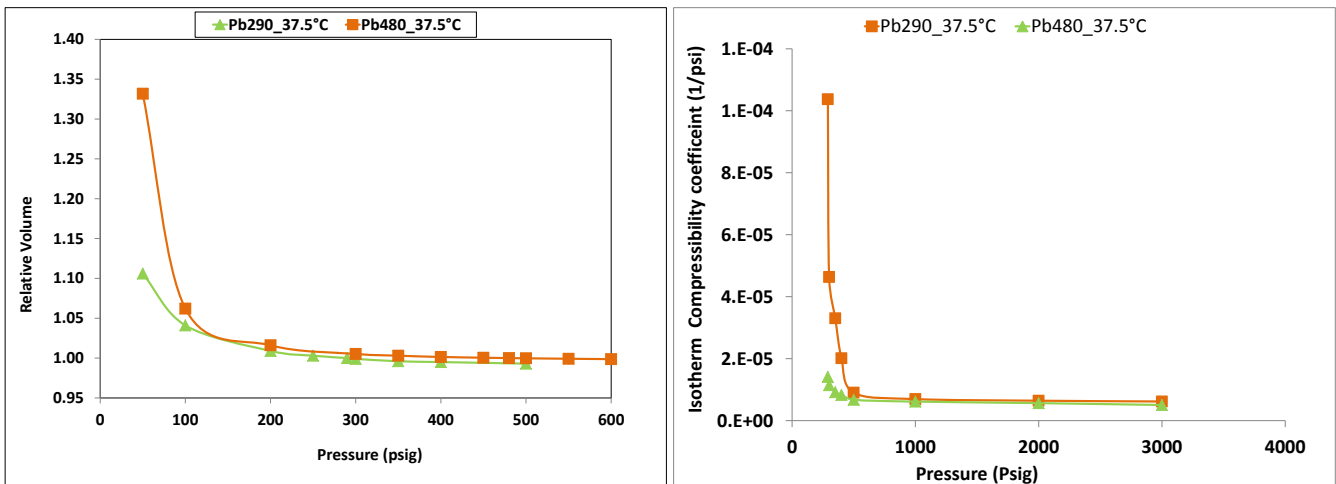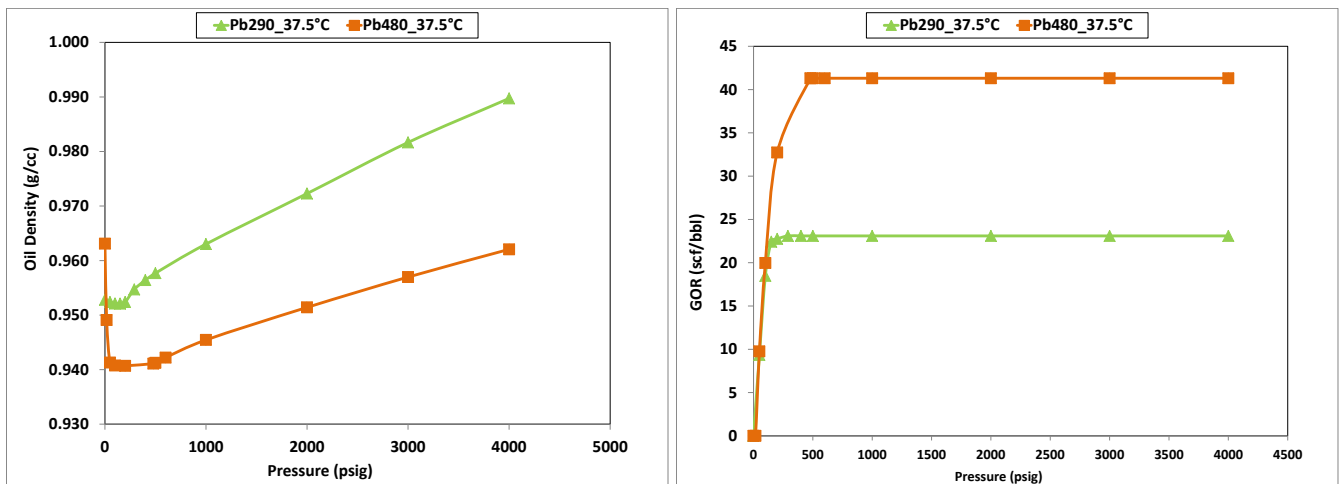

Fig. 5 ─ Relative Volume and compressibility coefficient of recombined samples obtained by CCE

The results of the Differential Vaporization consisted of GOR, relative volume, FVF, gas gravity, gas compressibility factor and liquid density. The oil density and GOR are presented in **Fig. 6**.
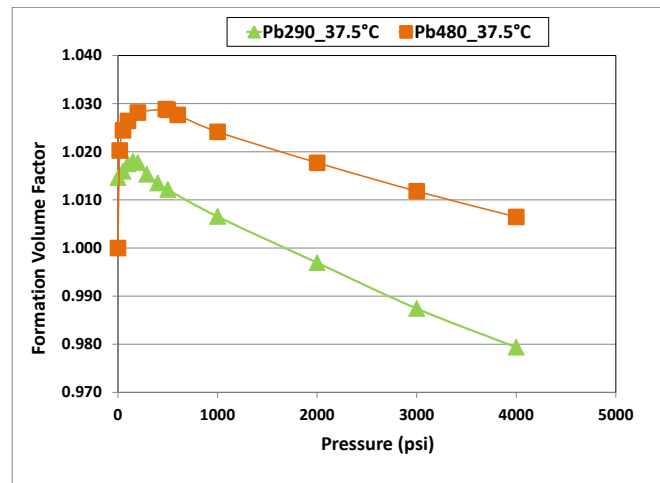
Fig. 6 ─GOR Oil density and FVF of recombined samples obtained by DV

Handling the sample at low temperature (37.5°C) was difficult and time consuming. The heavy nature of the oil itself and the very low working temperature used were important impediments to the stabilization of samples, leading to unusually long equilibration times. The oil viscosity results of PVT analysis 1 (recombined to a P_b of 290 psi) are presented in **Fig. 7**. The first impression from oil viscosity results obtained from this analysis was that viscosities were higher than results that were gathered from previous PVT analysis conducted for the Tambaredjo field (**Fig. 7**).
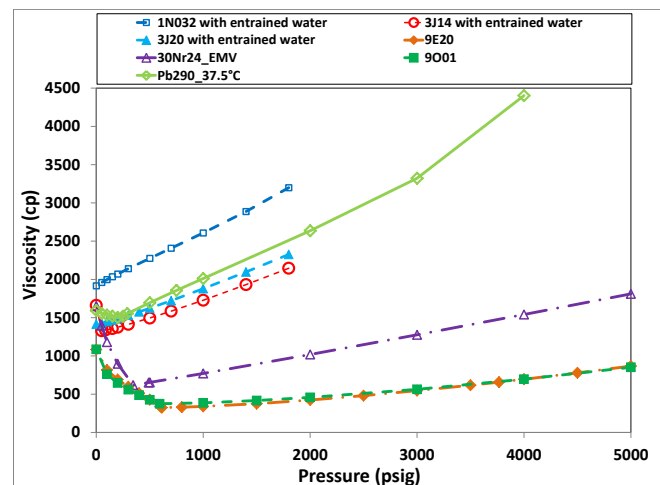
Fig. 7 ─Oil viscosity of PVT analysis 1 vs. previous PVT analysis

It was mentioned earlier that samples taken for PVT analysis within the Tambaredjo field were all surface samples. Some of these samples contained significant amounts of entrained water (emulsions). Moreover all the previous PVT analyses except for well 30Nr24 were measured with the rolling-ball viscometer, which does not seem to be the most accurate measuring tool for heavy oils. The EMV which is a more reliable viscosity measurement for heavy oils was used in well 30Nr24 and in this laboratory study. It was noticed that the viscosity results obtained from PVT analysis 1 (P_b 290 psi @ 37.5°C) seemed to be within a range of wells that appeared to have significant water emulsion content (wells 1N032, 3J20, 3J14). Comparison with well 30Nr24 showed that the viscosity of PVT analysis 1 was more or less twice as high. Above analysis indicated the possibility that the recombined sample still contained too much entrained water.

Dehydration of the oil samples by mechanical and thermal means was conducted for a period of three months. It is widely accepted that an increase in the water content results in an increase in the mixture viscosity by several orders of magnitude. Equation 2 was applied to assess the impact of water emulsion content in oil on viscosity results (Pilehvari, *et.al.*, 2007):

$$\mu_{emulsion} = \mu_{oil} x \, e^{kc} \hspace{4cm} \text{(Eq. 2)}$$

where c is the volumetric concentration of water in the emulsion and k is a constant equal to 7 for water cuts below 10% and 8 for water cuts above 10%. $\mu_{emulsion}$ is the measured oil viscosity of the sample that is entrained with water.

The viscosity of PVT analysis 1 was corrected for a water emulsion content of 10% and 20% using equation 2 and is presented in **Fig. 8**.
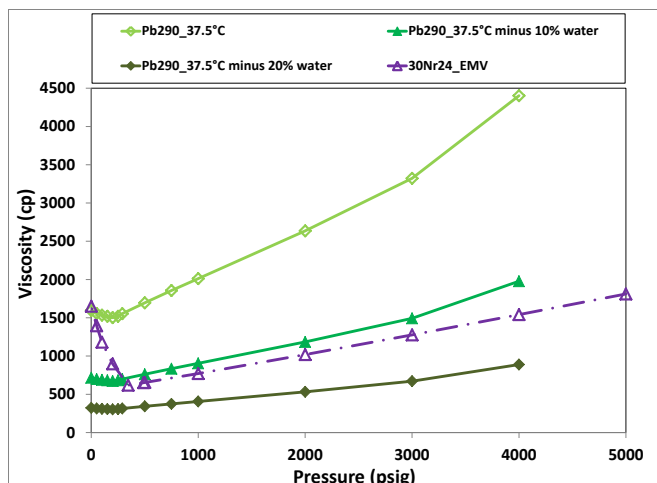

Fig. 8 ─Oil viscosity of PVT analysis 1 with removal of 10 & 20% water

According to Equation 2 removal of water from the recombined sample of PVT analysis 1 would reduce the viscosity with 50% and would reach near values of well 30Nr24, which was deemed to be the most reliable result among the historical data. In order to assess whether water was still present in the sample, a quantity was pumped off, heated and centrifuged at 10,000 rpm. However no further separation was noticed. The ultrasound bath was tried as well with no result. The liquid samples were strongly emulsified and it was impossible to break the emulsion by mechanical and thermal dehydration over an extended period of time. After numerous discussions whether the use of de-emulsifier would influence PVT results a few trials using an industrial de-emulsifier were conducted, which were successful in breaking the emulsion and improving the separation process. This lead to the decision to demulsify recombined samples for PVT analysis 2 using a 0.5% demulsifier.

In order to improve the water removal for PVT analysis 2, it was decided to use 'dead' oil instead of earlier used 'live' oil. With this process the sample with a demulsifier added could be visually monitored, immersed in an ultrasound bath, centrifuged at 10,000 rpm and then physically separated from the top $1/3^{rd}$ portion to ensure maximum water removal. Prior to conducting the PVT analysis the water content of the sample was measured using Karl Fischer titration method. After the water content was at acceptable levels ($\pm 2\%$) the sample was recombined to a bubble point of 480 psi. In this case a higher amount of gas was required, since the sample contained no solution gas. The oil viscosity results of PVT analysis 2 (recombined to a P_b of 480 psi) are presented in **Fig. 9**.
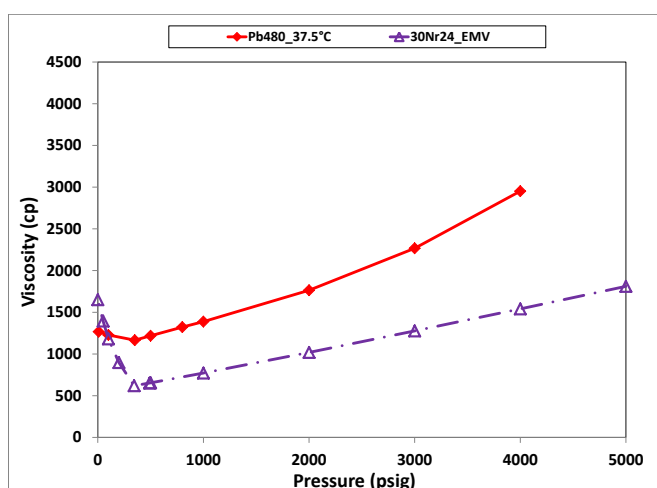

Fig. 9 ─ Oil viscosity of PVT analysis 2

The oil viscosity of PVT analysis 2 was significantly higher compared with well 30Nr24, which has a bubble point of 344 psi

and a GOR of 29. If the GOR and bubblepoint data of PVT analysis 1 and 2 are compared to the historical trend, it is noticed that these measurements are within a small range to the historical data trend line (**Fig. 10**).
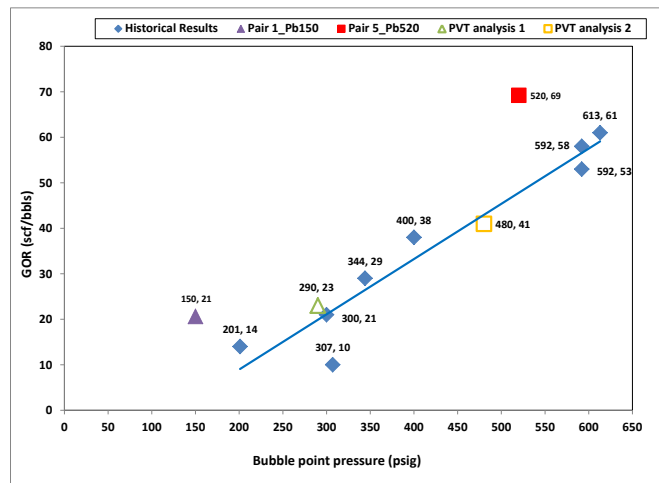

Fig. 10— Bubble point pressure vs. GOR for PVT analysis 1 and 2

Since there seems to be a good match of bubblepoint and GOR between this data and historical data with the exception of oil viscosity, a detailed analysis was performed on the oil properties of historical and these new results (**Fig. 11**).
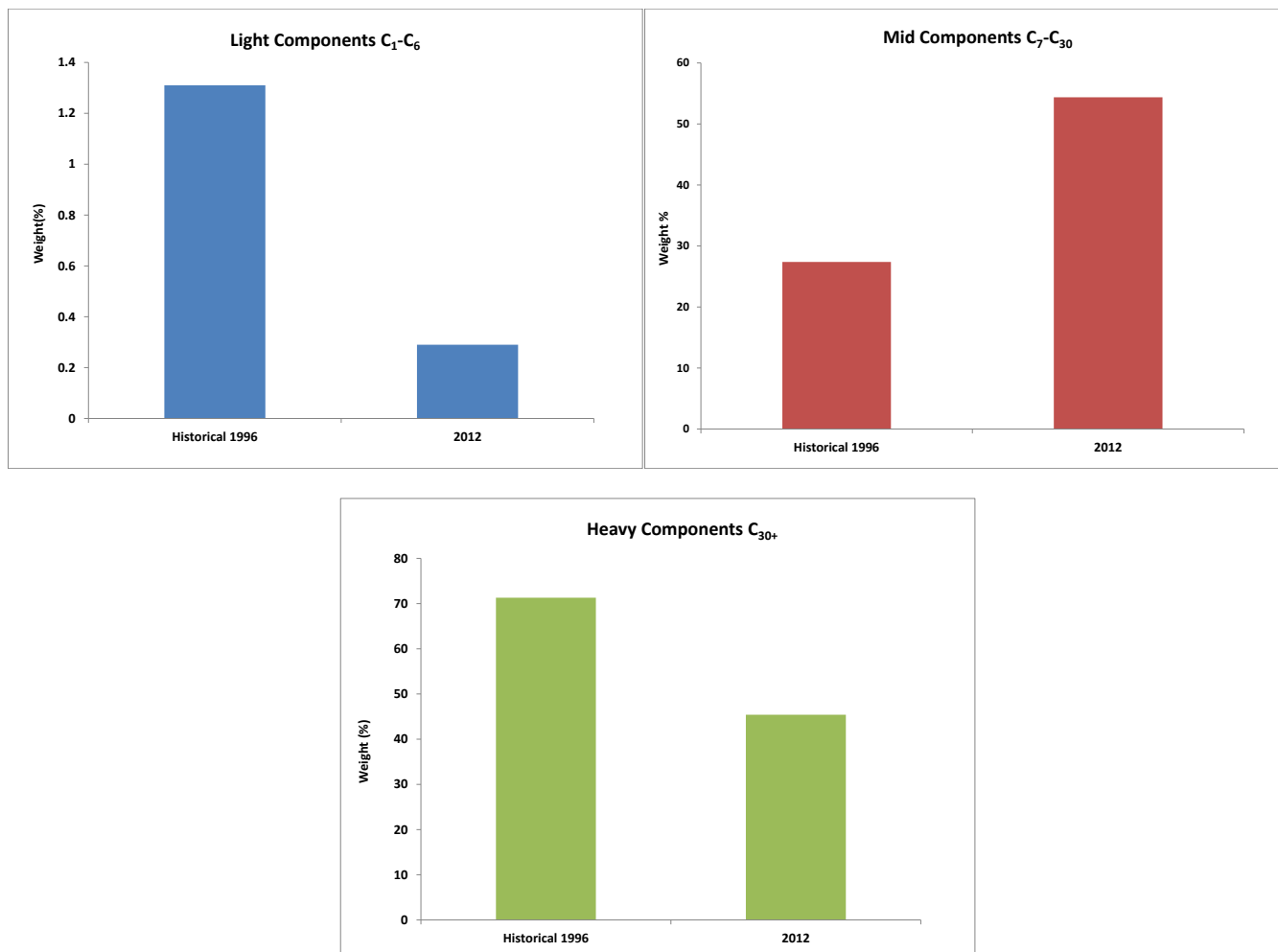

Fig.11—Changes of light, mid and heavy components in Tambaredjo oil composition after 16 years of production

Analysis of oil composition indicates a change of the components i.e. the oil samples in the current study seem to have fewer lighter components (C_1-C_6) and more mid components (C_7-C_{30}) than samples from the early stage of production. Most likely this is attributed to the vaporization of lighter components and a higher remaining amount of mid components after producing for several years.

Swelling tests. Fig. 12 to 14 show the 'live' viscosity versus pressure, swelling factor and bubble points at each stage for CO_2 ('live' and 'dead' oil) and N_2 injection (dead oil). Significant difficulties were encountered in trying to dissolve any of the two (CO_2 and N_2) gases into the oil, sometimes the process took weeks, using stirring, rotating, pressurizing (up to 10,000 psi) and heating (up to 1,500 ^{0}C) to dissolve the gas in the oil. Those conditions were much higher than the actual conditions in the reservoir.
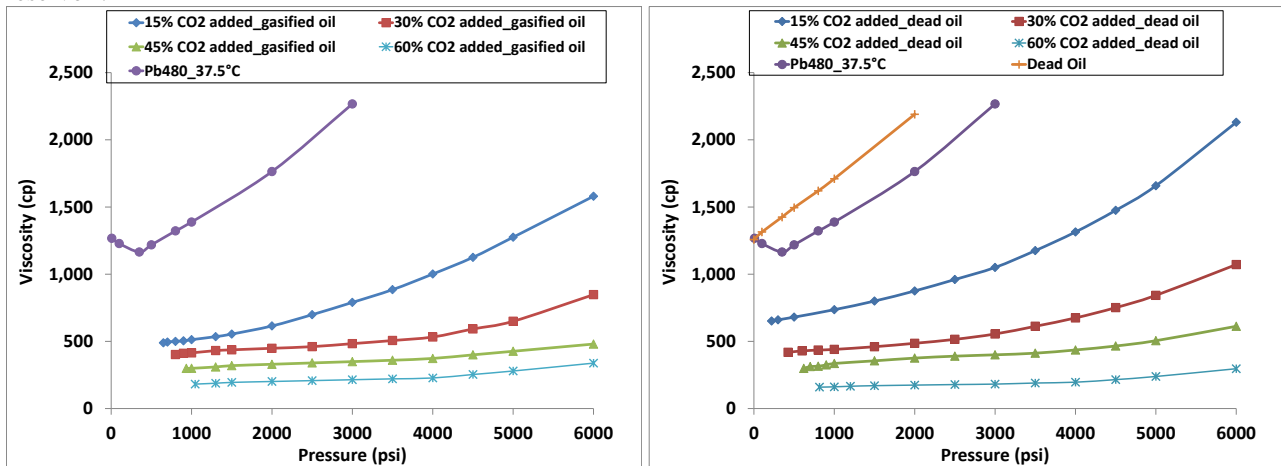

Fig. 12─Viscosity results of the various swollen samples for CO_2 injection for gasified (left) and 'dead' oil (right)

A significant reduction in the oil viscosity was observed with the dissolution of CO_2. i.e. CO_2 gas was able to reduce the oil viscosity with more than 50%. The viscosity reduction was higher in 'dead' oil than in 'live' oil.
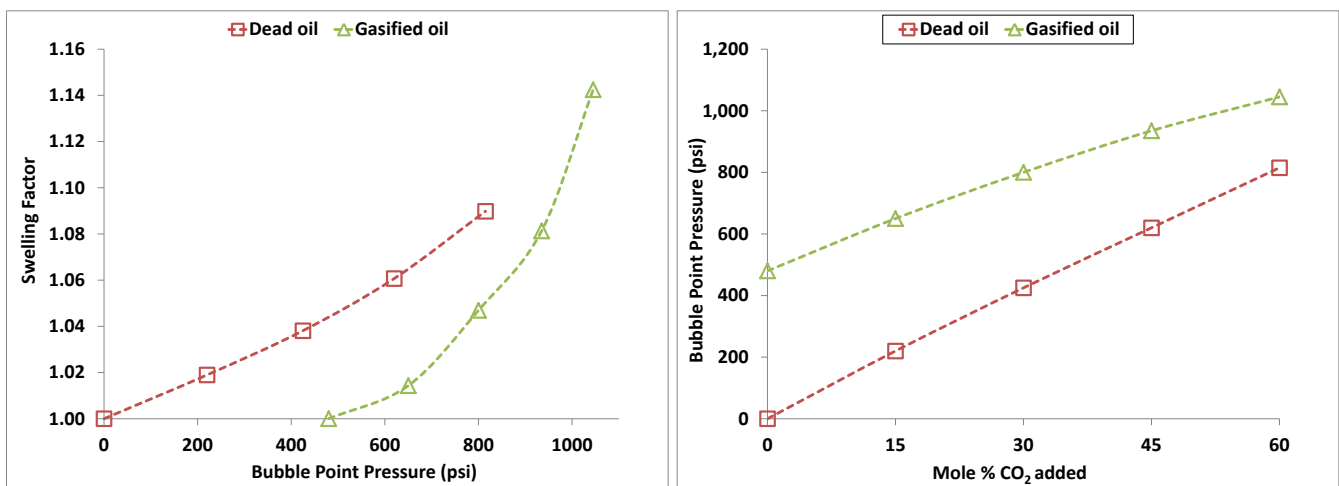

Fig. 13─Bubble Point and Swelling Factor results of the various swollen samples for CO_2 injection

CO_2 gas managed to swell the 'dead' and 'live' oil by 9 and 14% maximum respectively. Based on this data for a CO_2 WAG injection at an expected reservoir pressure of 400 psi swelling of the oil with CO_2 gas is expected to be in the range of 4% indicating a minimum dissolution of CO_2.
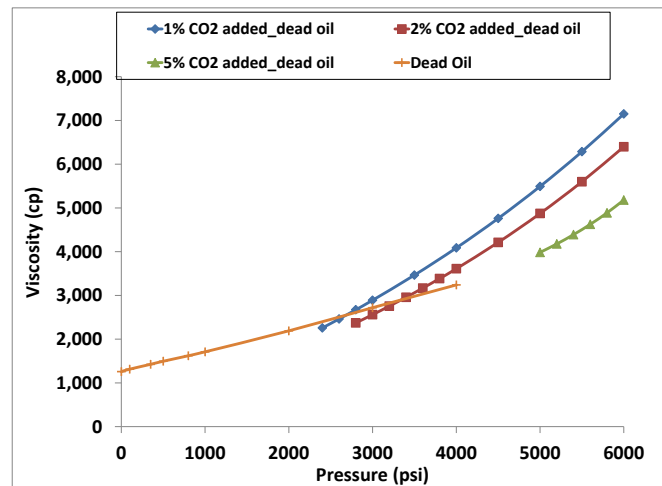
Fig. 14—Viscosity results of the various swollen samples for N₂ injection

A negligible reduction in the oil viscosity was observed with the dissolution of N_2. It was impossible even at very high temperatures and pressures to dissolve more than 5% mole N_2 in 'dead' oil, therefore the swelling with N_2 in 'live' oil was abandoned.

Conclusions

The analysis presented a degree of complexity initially underestimated which is highlighted by the following:

- Surface sampling is most likely the preferred sampling method for the study area of the Tambaredjo Oil Field, because the reservoir has been naturally depleted so the risk that the reservoirs are producing below the initial bubble point pressure is high.

- The best way now to represent reservoir fluids in this study area is to recombine surface samples to an expected initial bubble point pressure, although this have never been measured. Gas should be added to the flashed oil, in order to get what Staatsolie believes to be the best estimate of an initial bubble point pressure. This technique might not be the perfect solution, but it is most likely a practical solution to an unsolvable problem. Difficulties to accurately measure gas production rates for these low and unstable production rate wells will continue to occur.

- The QC of the samples revealed that the collected oil samples were heavily emulsified and the following challenges with regard to dehydration were experienced:
  - o Mechanical and thermal dehydration is very time consuming (more than 3 months) and cannot guarantee water removal to acceptably low levels. The use of demulsifiers are likely to be used to separate most of the entrained water.
  - o Visual determination for distinguishing a non-emulsified fluid is not possible. The water cut after the dehydration process should be determined qualitatively before continuing with PVT analysis (e.g. with Karl-Fischer method).
  - o The strong emulsion might be related to the relatively high asphaltenic and resins content in the oil.

- Dehydration of the highly emulsified Tambaredjo samples involved extensive mechanical, thermal and chemical separation processes, which should be considered for future PVT analysis.

- Viscosity results appeared to have been impacted by significant water emulsion content in the analyzed sample leading to different values than expected. When using demulsifiers measured values became closer to the expected ones, but were still higher (± 600 cp higher) if compared with the historical data. This is probably caused by change in the oil composition because of ten years of production.

- Very long stabilization times were required for the swelling of CO2 and N2 due to the difficulty in dissolving the gas into the oil. It was observed that the CO2 gas was capable to swell the oil with maximum 9% and reduce the oil viscosity with more than 50% while this was negligible for N2.

Acknowledgements

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