

# Bubble Point Simulation of Reservoir Oil and Carbon Dioxide Mixtures

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**Abstract** Accurate knowledge of the multicomponent phase behavior of carbon dioxide (CO<sub>2</sub>) with hydrocarbon fluids is needed in the design, operation and development of carbon dioxide-based enhanced oil recovery (EOR) techniques, in particular, understanding the phase behavior of CO<sub>2</sub> and hydrocarbon fluids system. In recent years, the possibility of sequestering CO<sub>2</sub> (a greenhouse gas) in underground (oil) reservoirs has been proposed. The feasibility will also be affected by the phase behavior of CO<sub>2</sub> in the presence of chemical species present in the reservoirs (Al-Marri in PVT, phase behavior and viscosity measurements and modeling of the ternary and binary systems of carbon dioxide + heavy hydrocarbon (*n*-eicosane) + light gas (ethane or propane), Ph.D. Thesis, University of Southern California, 2006). PVT viscosity and vapor–liquid equilibria are important in EOR process, reservoir simulations and process design. Phase behavior consists of two parts, in the first part the recombination process takes place by inserting the data of surface fluids into the PVT simulation to determine various fluid properties and especially the bubble point at reservoir temperature. In the second part, the swelling test is introduced by inserting the data of carbon dioxide (99.6% purity) as injection fluid into the recombined fluid to investigate the swelling factors. The modified Peng–Robinson equation of state was used for predicting saturation pressure. For fluid mixtures, the Van Der Waals mixing rules are commonly used. Results of the

simulation were compared with the experimental data showing that the saturation pressure of the recombined fluid/CO<sub>2</sub> system was strongly affected by the concentration of carbon dioxide. Thus, this enhanced the oil recovery from heavy oil reservoirs.

**Keywords** Phase behavior · Surface fluid samples · Recombination · Heavy oil · Carbon dioxide · Swelling · Enhanced oil recovery

## 1 Introduction

Due to the difficulty and costs of bottom-hole samples measurements, the objective of surface sampling of reservoir fluids mainly consists of sampling individual gas and liquid streams from a production separator. The two samples were mixed together in the same proportion to obtain a recombined sample as a representative of the reservoir oil [2].

The important of enhanced oil recovery (EOR) methods emphasized on increasing the displacement efficiency as their main recovery mechanism by injecting gas. Carbon dioxide flooding is among the most potential EOR approaches for the light, medium and heavy oil reservoirs and has been effectively used in a number of worldwide basins because it reaches miscibility at lower pressure, as compared to other hydrocarbon gases, swells the oil, reduces its viscosity and reaches supercritical state at the pressure and temperature of most oil reservoirs resulting in oil-like density that reduces override effects [3]. Carbon dioxide not only can recover more oil but also considerably reduces greenhouse gas emissions. Several factors affect the mobilization efficiency; these factors include pore structure, rock geometry, fluid properties and flooding rate.

Phase behavior simulation depends on the compositions data of the oil and injected fluid and as well as on reser-

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voir pressure and temperature. PVT simulation predicts the thermodynamic properties of the fluid such as saturation pressure, density, viscosity,  $z$ -factor of vapor phase, thermal conductivity and compressibility for liquid and vapor phases.

In the first step, the surface sample fluids data were introduced into PVT simulation in order to reproduce the original oil composition. The simulation predicts the thermodynamic properties of the recombined fluids such as saturation pressure, density, viscosity,  $z$ -factor of vapor phase, thermal conductivity and compressibility at the reservoir saturation pressure and bottom-hole temperature.

In the second step, different CO<sub>2</sub> concentrations to be injected into the recombined fluid were introduced into the PVT simulation to investigate the oil swelling rate and establish the relationship between saturation pressure and the injected CO<sub>2</sub> mass fraction. Finally, the simulation results were compared with the experimental data, and the average of the absolute relative error between experimental data and predicted saturation pressures was 1.008% for given well.

## 2 Simulation Section

### 2.1 Field Data and Materials Used

The field data were collected and analyzed the bottom-hole sample from JZR oil field at depth of 5000ft. Table 1 presents the JZR bottom-hole fluid compositions provided by the operating company. The reservoir initial pressure, reservoir temperature and bubble point pressure at bottom-hole temperature are 2420 psia, 127 °F and 1843 psia, respectively. The stock-tank oil is heavy crude petroleum having API gravity 32.2.

The surface sampling fluids compositions mainly consist of sampling individual gas and liquid streams from a production separator which were used in the simulation to mix together in the same proportion in which they are recombined to reproduce a representative of the reservoir fluids as represented in Table 2.

### 2.2 Simulation Procedure

The simulation can perform calculations using either the defined components properties or the characterized properties. Generally, the calculations with characterization for reservoir fluids are more accurate. The simulation procedure begins by inserting data of surface fluids at reservoir conditions pressure 2420 psia and 127 °F. The recombination process can be based on the gas/oil ratio or the saturation pressure of the reservoir fluids; in this work, it is based on saturation pressure 1843 psia and reservoir temperature 127 °F, respectively.

The phase envelope of reservoir fluid has been generated by the PVT simulation as shown in Fig. 1. The simulation

**Table 1** JZR reservoir fluid compositions

Component	Reservoir fluid (mol%)
N <sub>2</sub>	1.3643
CO <sub>2</sub>	6.7853
C <sub>1</sub> H <sub>4</sub>	27.034
C <sub>2</sub> H <sub>6</sub>	5.5795
C <sub>3</sub> H <sub>8</sub>	5.7348
<i>i</i> C <sub>4</sub> H <sub>10</sub>	1.8855
<i>n</i> C <sub>4</sub> H <sub>10</sub>	3.3868
<i>i</i> C <sub>5</sub> H <sub>12</sub>	2.6760
<i>n</i> C <sub>5</sub> H <sub>12</sub>	3.7068
C <sub>6</sub> H <sub>14</sub>	5.1205
C <sub>7</sub> H <sub>16</sub>	5.5880
C <sub>8</sub> H <sub>18</sub>	3.2930
C <sub>9</sub> H <sub>20</sub>	6.2320
C <sub>10</sub> H <sub>22</sub>	2.7550
C <sub>11+</sub>	18.887

**Table 2** JZR surface sampling fluid's compositions

Component	Flashed liquid (mol%)	Flashed gas (mol%)
N <sub>2</sub>	0.02	2.85
CO <sub>2</sub>	0.33	13.92
C <sub>1</sub> H <sub>4</sub>	0.80	56.03
C <sub>2</sub> H <sub>6</sub>	1.20	10.42
C <sub>3</sub> H <sub>8</sub>	2.50	9.31
<i>i</i> C <sub>4</sub> H <sub>10</sub>	1.99	1.77
<i>n</i> C <sub>4</sub> H <sub>10</sub>	3.80	2.93
<i>i</i> C <sub>5</sub> H <sub>12</sub>	4.12	1.08
<i>n</i> C <sub>5</sub> H <sub>12</sub>	6.21	0.94
C <sub>6</sub> H <sub>14</sub>	9.31	0.49
C <sub>7+</sub>	69.72	0.26
MW	192.59	28.39
Mole ratio	0.518	0.482
C <sub>7+</sub> MW	247	

results were compared with the experimental data, and the average of the absolute relative error between reservoir compositions and predicted recombined fluid compositions was 1.008%. Table 3 and Fig. 2 represent the comparison of reservoir fluid with the recombined fluid compositions.

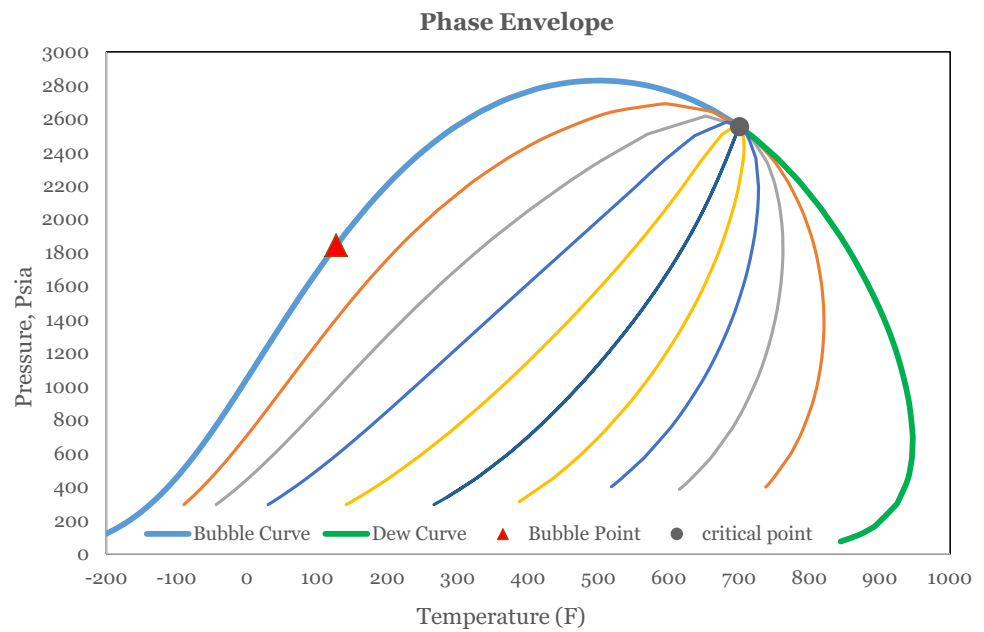
## 3 Thermodynamic Modeling

### 3.1 The Modified Peng–Robinson Equation

In the PVT simulation, the Peng–Robinson (1978) equation of state and Van Dar Waal's mixing rule [4] has been selected.



**Fig. 1** Phase envelope of selected reservoir



**Table 3** Comparison of reservoir fluid with recombined fluid compositions at reservoir conditions

Component	Reservoir fluid (mol%)	Recombined fluid (mol%)	Average absolute error (%)
N <sub>2</sub>	1.3643	1.3843	1.4691
CO <sub>2</sub>	6.7853	6.8817	1.4213
C <sub>1</sub> H <sub>4</sub>	27.034	27.426	1.4514
C <sub>2</sub> H <sub>6</sub>	5.5795	5.6450	1.1733
C <sub>3</sub> H <sub>8</sub>	5.7348	5.7831	0.8422
iC <sub>4</sub> H <sub>10</sub>	1.8855	1.8839	0.0828
nC <sub>4</sub> H <sub>10</sub>	3.3868	3.3806	0.1839
iC <sub>5</sub> H <sub>12</sub>	2.6760	2.6544	0.8066
nC <sub>5</sub> H <sub>12</sub>	3.7068	3.6693	1.0108
C <sub>6</sub> H <sub>14</sub>	5.1205	5.0579	1.2230
C <sub>7+</sub>	36.755	36.233	1.4193
		AARE (%)	1.008

The Peng Robinson EOS which is used is:

$$P = \frac{RT}{v-b} = \frac{a}{(v+b)(v+b+2c) + (b+c)(v-b)}$$

The energy parameter of component  $i$  is estimated by

$$a_i = \Omega_a \frac{R^2 T_{ci}^2}{P_{ci}} a(T_{ri})$$

$$a(T_{ci}) = \left[ 1 + a_0 \left( 1 - \sqrt{T_{ri}} \right) + a_1 + a_2 (1 - T_r) (0.7 - T_r) \right]^2$$

For non-polar (hydrocarbon) components,  $\alpha_1$ ,  $\alpha_2$  are equal to zero, for the PR EOS (1978),  $\alpha_0$  is giving by:

$$a_0 = 0.3764 + 1.5422\omega_i - 0.2699\omega_i^2 \quad \omega \leq 0.49$$

$$a_0 = 0.379642 + 1.48503\omega_i - 0.164423\omega_i^2 - 0.016666\omega_i^3$$

$$\omega \geq 0.49$$

$$b_i = \Omega_b \frac{RT_{ci}}{P_{ci}} - c_i$$

where  $c_i$  = the volume shift parameter of component  $i$ .

For the Peng–Robinson:  $\Omega_a = 0.457236$ ,  $\Omega_b = 0.077796$ .

The dimensionless volume shift parameter  $s_i$  is defined as

$$s_i = \frac{c_i}{b_i + c_i} = \frac{c_i}{\Omega_b \frac{RT_{ci}}{P_{ci}}}$$

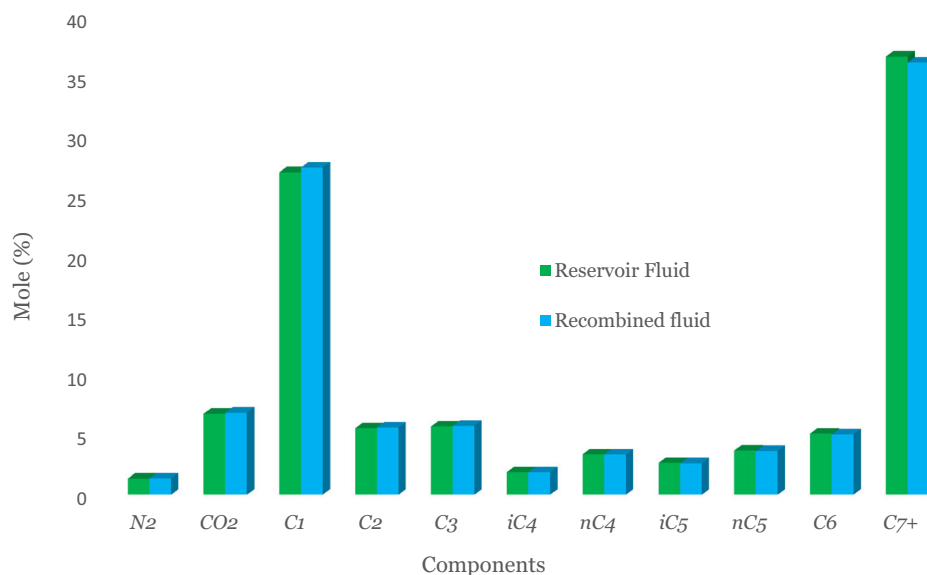
The volume shift parameters are determined by matching the experimental density data at  $T_r = 0.7$  for a lot of components; the  $s$  values are stored in the simulation CompBank. If they are not available, the parameters for light components are calculated by Peng–Robinson EOS:

$$s_i = 0.4772\omega_i - 0.154700.$$

For a heavy component, the volume shift parameters is determined by matching its specific gravity (SG) at standard conditions.

Application of the EOS to fluid mixtures requires a mixing rule in order to describe the mixture from the properties of its pure constituents. For hydrocarbon systems, the van der Waals mixing rules are commonly used; here, it is used with only temperature-independent  $k_{ij}$



**Fig. 2** Reservoir fluid versus recombined fluid

$$a = \sum_i \sum_j z_i z_j \sqrt{a_i a_j} (1 - k_{ij}) .$$

$$b = \sum_i z_i b_i$$

$$c = \sum_i z_i c_i$$

### 3.2 EOS Tuning

The  $k_{ij}$  are usually referred as binary interaction parameters (BIP) and are usually calculated by parameterizing the EOS with experimental  $K$ -values. The BIP values in the simulation and the alternative method for evaluating BIPs were proposed by Chueh and Prauznitz:

$$k_{ij} = \left[ 1 - \left( \frac{2 (v_{ci} v_{cj})^{1/6}}{v_{ci}^{1/3} v_{cj}^{1/3}} \right)^3 \right]$$

where  $v_{ci}$  = the critical molar volume of the component  $i$ .

The value of  $B$  is commonly fixed to 6, and the coefficient  $A$  is adjusted to match measured saturation pressures of the mixture. Since correlations for critical pressure are in general less accurate than correlations for critical temperature, the critical pressure of the  $C_{7+}$  fraction together with the binary interaction parameter was used as regression variables to fit experimental pressure saturation data with the modified Peng–Robinson EOS [5]. The parameter  $T_c$  is used in tuning to fix the saturation pressure of the fluid.

### 4 Swelling Test

Carbon dioxide is a powerful agent for EOR. Its reaches miscibility at lower reservoir pressure compared to nitrogen

**Table 4** Saturation pressure with different CO<sub>2</sub> concentrations and comparison between experimental and simulation data

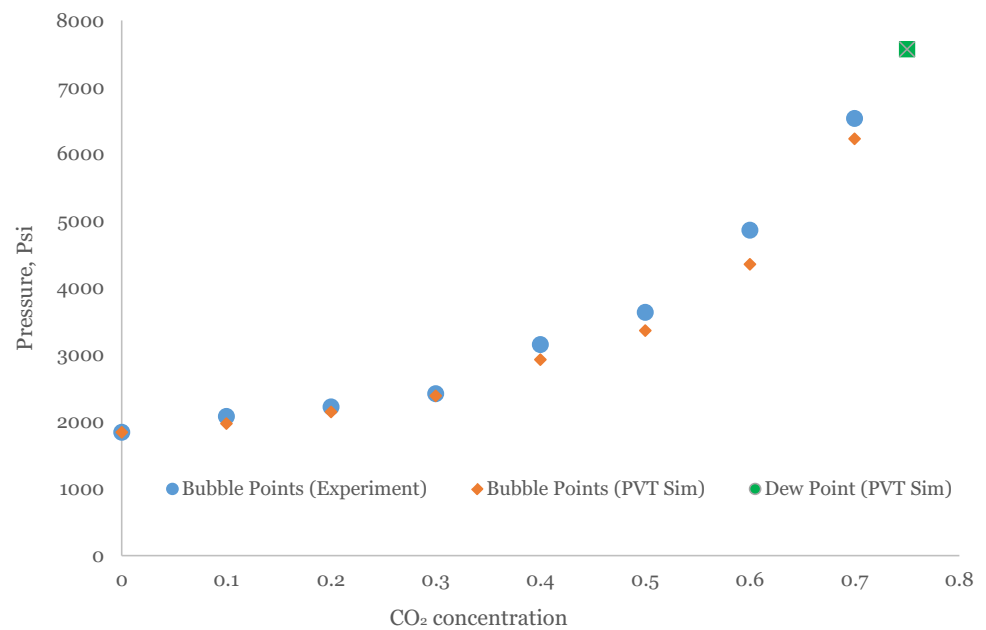
$w_{CO_2}$	$P^{Bubble}$ (Experiment), Psia	$P^{Bubble}$ (PVT Sim), Psia	AARE (%)
0.0	1843	1843.0	0.000
0.1	2081	1974.3	5.1410
0.2	2220	2146.8	3.2889
0.3	2421	2389.3	1.3216
0.4	3154	2926.5	7.1983
0.5	3637	3362.8	7.5366
0.6	4861	4353.4	10.438
0.7	6531	6227.9	4.6409
0.75		Dew Point = 7568.0	
		Average ARE (%)	4.9461

and hydrocarbon gases, swells the oil, reduces its viscosity and reaches supercritical state at the pressure and temperature of most oil reservoirs resulting in oil-like density that reduces override effects, the CO<sub>2</sub> used in this simulation assumed to be 99.6% purity. This assumption was made on the basis of real purity of CO<sub>2</sub> gas as provided by the supplier company.

The PVT simulation was also used to perform the swelling test by injecting CO<sub>2</sub> gas to the recombined fluid to investigate how much oil is going to swell and to establish the relation between CO<sub>2</sub> concentration and saturation pressure; this process helps in EOR in the heavy oil reservoirs [6]. The swelling factor is defined as the ratio between the volumes of a saturated mixture of CO<sub>2</sub>/recombined fluid and the volume of saturated recombined fluid at the reservoir temperature [7].



**Fig. 3** Saturation pressure measurement by experimental and simulation



$$V^{sw} = \left( \frac{V^{01}}{V^0} \right)$$

where  $V^{sw}$ : new saturation volume,  $V^0$ : at each incremental addition of CO<sub>2</sub>,  $V^{01}$ : the original saturation pressure.

The error in the predicted saturation pressure relative to the experimental data values was 4.94% as shown in Table 4, and Fig. 3 shows clearly the values almost matching between the simulation and experimental work results.

As the injected mass fraction of CO<sub>2</sub> was higher than 0.3, the AARE were become significantly greater due to the interaction between the hydrocarbon molecules which were affected in such a way that a heavy phase isolates the light hydrocarbon fraction in the form of vapor phase as the pressure is lowered. Table 5 shows the change in composition of oil components as a result of mixing various concentration of CO<sub>2</sub> with recombined oil sample.

## 5 Routine Laboratory Tests

These are several laboratory tests that are routinely conducted to characterize the reservoir hydrocarbon fluid. They include: Constant-composition expansion, Differential liberation, Separator tests and Constant-volume depletion which are presented in “Appendix A”.

## 6 Results and Discussion

PVT simulation can perform a perfect job on recombination process of surface sampling fluids at reservoir condition, and

the average absolute error was about 1.008% based on the saturation pressure. But before characterization, the saturation pressure was far away from the experimental saturation pressure; simulation has model tuning to converge C<sub>7+</sub> either critical pressure, critical temperature or the acentric factor. In most cases, critical temperature is used because it has less effect to obtain the converged saturation pressure 1843 psia with average relative deviation before and after tuning were 1.08%, 1.002, respectively.

CO<sub>2</sub> injection is used in heavy oil reservoir fluids to improve the oil recovery, and by reducing the viscosity and improving the mobility of the fluid, the heavier oil become much more lighter depending on the CO<sub>2</sub> mass concentration, as higher CO<sub>2</sub> concentration the lighter oil were obtain, but up to some limit, sometimes we observed that at higher CO<sub>2</sub> concentration above 65 or 70%, the bubble point coverage to dew point and the oil reserve acts as gas reservoir. In swelling test, the error in the predicted saturation pressure (CO<sub>2</sub>/recombined fluid at different mass concentration) relative to the experimental data values was 4.94%. The simulation can work perfectly while saving time and cost along with overall error less than 5%.

## 7 Conclusions

In this work, the simulation data and thermodynamic modeling of the system carbon dioxide/JZR oil at high temperature and high pressure were performed. These data are useful for EOR investigations. Result shows that the temperature has a minor effect to the saturation pressure of the system in contrast to the carbon dioxide concentration which showed



**Table 5** Oil components change in composition with various CO<sub>2</sub> mass concentration

Comp	WCO <sub>2</sub> = 0.1, (P <sub>b</sub> = 1947 psia)		WCO <sub>2</sub> = 0.2, (P <sub>b</sub> = 2146 psia)		WCO <sub>2</sub> = 0.3, (P <sub>b</sub> = 2389 psia)		WCO <sub>2</sub> = 0.4, (P <sub>b</sub> = 2926 psia)		WCO <sub>2</sub> = 0.5, (P <sub>b</sub> = 3362 psia)		WCO <sub>2</sub> = 0.6, (P <sub>b</sub> = 4353 psia)		WCO <sub>2</sub> = 0.7, (P <sub>b</sub> = 6227 psia)	
	Liquid (mol%)	Vapor (mol%)	Liquid (mol%)	Vapor (mol%)	Liquid (mol%)	Vapor (mol%)	Liquid (mol%)	Vapor (mol%)	Liquid (mol%)	Vapor (mol%)	Liquid (mol%)	Vapor (mol%)	Liquid (mol%)	Vapor (mol%)
N <sub>2</sub>	1.2480	6.6123	1.1116	4.9191	0.9752	3.2455	0.8387	1.6410	0.7372	0.9233	0.7023	0.8688	0.5658	0.6413
CO <sub>2</sub>	16.154	24.731	25.426	38.066	34.698	50.683	43.969	59.343	47.313	62.030	53.241	60.138	62.513	68.527
C <sub>1</sub>	24.716	58.156	22.003	46.529	19.290	34.583	16.578	22.303	14.978	15.470	13.865	15.064	11.152	11.423
C <sub>2</sub>	5.0889	4.7643	4.5323	4.2777	3.9758	3.8122	3.4192	3.3525	3.1482	2.8188	2.8627	2.8342	2.3062	2.2057
C <sub>3</sub>	5.2051	2.6361	4.6267	2.5766	4.0484	2.6131	3.4700	2.8191	3.2186	2.6486	2.8917	2.7175	2.3134	2.1227
<i>i</i> -C <sub>4</sub>	1.6955	0.5797	1.5071	0.6058	1.3187	0.6776	1.1303	0.8404	1.0523	0.8391	0.9420	0.8694	0.7536	0.6797
<i>n</i> -C <sub>4</sub>	3.0424	0.8473	2.7044	0.9047	2.3663	1.0494	2.0283	1.3935	1.8955	1.4569	1.6902	1.5221	1.3522	1.2012
<i>i</i> -C <sub>5</sub>	2.3889	0.4516	2.1234	0.5153	1.8580	0.6597	1.5926	1.0083	1.4928	1.1166	1.3271	1.1775	1.0617	0.9300
<i>n</i> -C <sub>5</sub>	3.3022	0.5217	2.9353	0.6084	2.5684	0.8053	2.2015	1.3059	2.0693	1.5043	1.8345	1.5971	1.4676	1.2692
C <sub>6</sub>	4.5517	0.4222	4.0459	0.5350	3.5402	0.8004	3.0344	1.5567	2.8683	1.9672	2.5287	2.1226	2.0230	1.6959
C <sub>7+</sub>	32.6069	0.2779	28.984	0.4630	25.361	1.0706	21.738	4.4366	21.228	9.2258	18.115	11.089	14.492	9.3040

stronger influence. The modified Peng–Robinson EOS tuned with the critical pressure of C<sub>7+</sub> was suitable to correlate the saturation pressure of the system JZR oil/carbon dioxide.

As the CO<sub>2</sub> mass fraction was greater than 0.3, significant impact on the saturation pressure has become greater due to the interaction between the hydrocarbons molecules which were affected in such a way that a heavy phase isolates the light hydrocarbon fraction in the form of vapor phase as the pressure is lowered.

## A Routine Laboratory Test Using PVT Simulation

### A.1 PVT Simulation

The PVTpro (OilPhase-DBR) simulation is Schlumberger software, Canada Ltd. The PVTpro version 5.10 was used in this work, the following are several laboratory tests that are routinely conducted to characterize the reservoir hydrocarbon fluid.

### A.2 The Constant-Composition Expansion (CCE) Test

The main aim of the CCE test (Fig. 4) is to determine the initial fluid saturation pressure. The fluid is initially held in a cell in a single phase. At pressures above the saturation pressure, only the single-phase volume is measured. The pressure reduction has to be made in several steps, and at each step, the liquid and vapor volumes are measured. The relative volume is calculated as the ratio of fluid volume at any pressure to the fluid volume at saturation pressure. The relative volume is then plotted against pressure to yield the volume–pressure relationship.

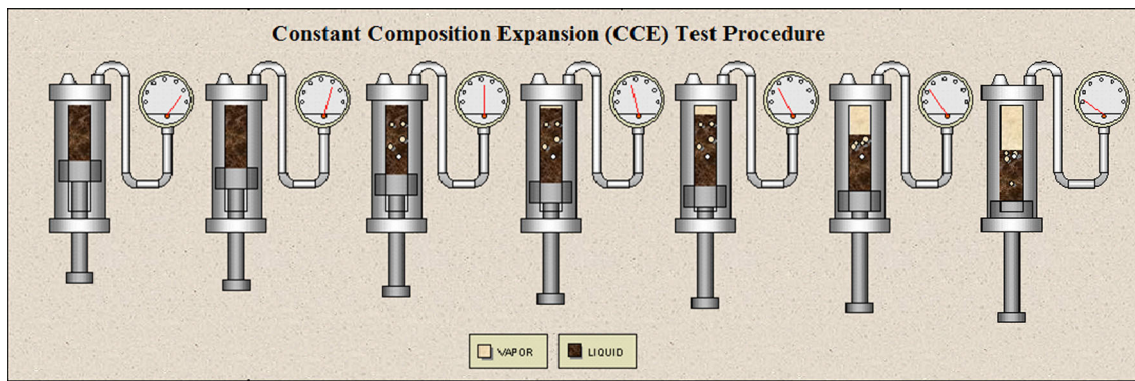
The CCE test was performed at  $P = 1843$  psia and  $T = 127$  °F. The calculated properties are shown in Table 6. Several plots can be generated from the results for the various properties of the reservoir fluid as a function of pressure such as relative total liquid volume ( $V_{liq}/V_{tot}$ ), relative saturated liquid volume ( $V_{liq}/V_{sat}$ ), relative volume ( $V_{rel}$ ), liquid density, liquid viscosity, gas molar weight, gas specific gravity, gas viscosity, Z-factor, Y-function, compressibility, bulk density, IFT and gas density. Among these properties : relative total liquid volume ( $V_{liq}/V_{tot}$ ), relative saturated liquid volume ( $V_{liq}/V_{sat}$ ), relative volume ( $V_{rel}$ ), liquid density, liquid viscosity, gas molar weight, gas specific gravity, gas viscosity, Z-factor, Y-function, compressibility, bulk density, IFT and gas density.

### A.3 The Differential Liberation (DL) Test

The differential liberation test is schematically shown in Fig. 5; during this test, the reservoir fluid is depleted by 6–10 steps from the saturation pressure to atmospheric pressure



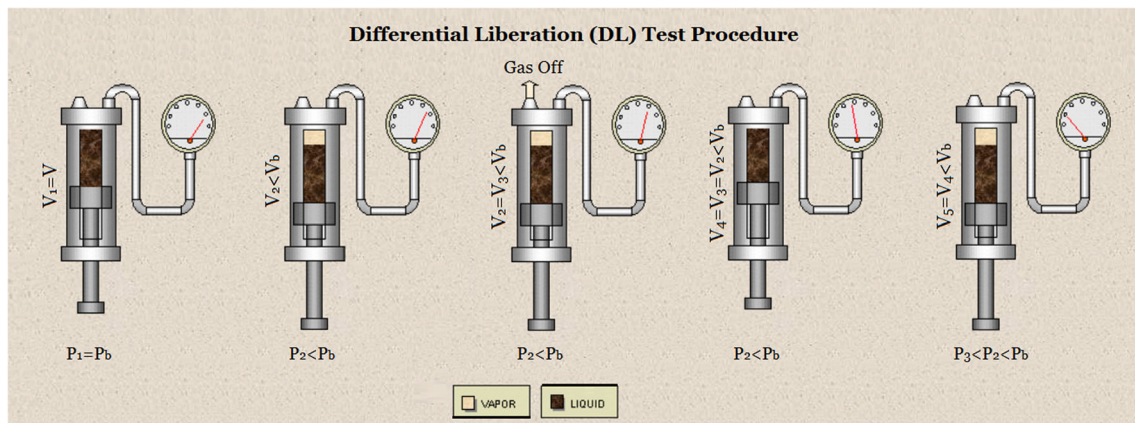




**Fig. 4** CCE test procedure

**Table 6** Results of the CCE test for JZR oil

Pressure	Total Liq. Vol. %	Sat. Liq. Vol. %	Rel. Vol.	Liq. density	Liq. viscosity	Gas MW	Gas specific gravity	Gas viscosity	Z-factor	Y Function	Compressibility	Bulk Density	Interfacial tension, IFT	Gas density
Psia	$V_{liq}/V_{tot}$	$V_{liq}/V_{sat}$	$V_{tot}/V_{sat}$	lb/ft <sup>3</sup>	cP	lb/lbmol	Air=1	cP	$PV/RT$		1/psia	lb/ft <sup>3</sup>	dyne/cm	lb/ft <sup>3</sup>
3000	100.0	98.87	0.99	48.20	0.79						0.00	48.20		
2356	100.0	99.47	0.99	47.90	0.74						0.00	47.90		
2033	100.0	99.80	1.00	47.70	0.71						0.00	47.70		
1843	100.0	100.0	1.00	47.60	0.70						0.00	47.60	6.69	
1389	85.42	96.18	1.13	48.50	0.77	23.01	0.02	0.02	0.83	2.60		42.30	9.15	6.10
1067	70.99	93.32	1.31	49.20	0.85	23.18	0.02	0.02	0.86	2.31		36.20	11.27	4.60
744	52.51	90.25	1.72	49.90	0.97	23.66	0.01	0.01	0.89	2.05		27.70	13.68	3.20
422	30.14	86.66	2.87	50.80	1.17	24.75	0.01	0.01	0.92	1.79		16.60	16.42	1.80
100	6.10	80.04	13.12	52.30	1.69	28.64	0.01	0.01	0.97	1.44		3.60	19.84	0.50
14.7	0.68	72.15	106.2	54.00	2.69	35.10	0.01	0.01	0.99	1.18		0.40	21.43	0.08



**Fig. 5** Schematic diagram of the differential liberation (DL) test (Note  $V_1 = V_b$  at  $P_b$ )

and the solution gas liberated at each step which is continuously removed from contact with its equilibrium oil and the residual density at standard condition was 53.9 lb/ft<sup>3</sup>.

Table 7 shows the calculated properties of the gas and liquid phases of the DL test as a function of pressure. These properties include liquid volume, liquid density, liq-

uid viscosity, oil formation volume factor (FVF<sub>o</sub>), solution gas-to-oil ratio (GORS), liberated gas-to-oil ratio (GORL), gas molar mass, gas viscosity, gas Z-factor, gas formation volume factor (FVF<sub>g</sub>), gas gravity and gas density as well as interfacial tension (IFT).



**Table 7** Results of differential liberation (DL) test for JZR oil

Pressure	Liq. Density	Liq. Viscosity	Oil FVF	Soln. GOR	Gas Lib. GOR	Gas Gas MW	Gas Viscosity	Viscos-Gas Factor	Z-Gas FVF	Gas Gravity	IFT	Liq. Vol. %	Gas Density
Psia	lb/ft <sup>3</sup>	cP	bbbl/STB	SCF/STB	SCF/STB	lb/lbmol	cP	PV/RT	ft <sup>3</sup> /scf	Air=1	dyne/cm	V <sub>liq</sub> /V <sub>sat</sub>	lb/ft <sup>3</sup>
1843	47.6	0.697	1.317	615.3	0	23.11	1.82E-02	0.8155	0.0074	0.7978	6.689	100	8.3
1456	48.3	0.761	1.275	512	103.3	23	1.65E-02	0.8299	0.0095	0.7940	8.753	96.76	6.4
1262	48.7	0.8	1.253	460.8	154.5	23.03	1.58E-02	0.8404	0.0111	0.7952	9.926	95.14	5.5
1068	49.1	0.848	1.232	409.1	206.2	23.17	1.52E-02	0.8535	0.0133	0.7998	11.201	93.5	4.6
875	49.5	0.906	1.21	356.8	258.5	23.46	1.46E-02	0.8691	0.0166	0.8100	12.577	91.82	3.8
681	50	0.98	1.187	303.5	311.8	24.02	1.40E-02	0.8875	0.0217	0.8293	14.056	90.1	2.9
487	50.5	1.076	1.163	248.6	366.7	25.08	1.36E-02	0.9084	0.0311	0.8658	15.638	88.29	2.1
294	51	1.212	1.137	189.8	425.6	27.29	1.30E-02	0.9322	0.0529	0.9420	17.344	86.28	1.4
100	51.7	1.448	1.097	110.8	504.5	33.9	1.17E-02	0.9607	0.1610	1.1704	19.331	83.24	0.6
14.7	52.9	2.015	1.019	0	615.3	51.56	9.20E-03	0.9839	1.1360	1.7801	20.907	77.32	0.1

**Table 8** Separator after-stage properties of the gas and liquid phases for JZR well (at saturation pressure: total GOR = 531.4 scf/STB and FVF = 1.261)

Properties	Pressure	Temperature	GOR	Liq. Density	Liq. Viscosity	Oil FVF	Gas Viscosity	Gas z-Factor	Gas FVF	Sep. GOR	Gas MW	Gas Gravity	Interfacial Tension, IFT	Heat Val.	Gas Density
Unites	Psia	°F	scf/STB	Lb/ft <sup>3</sup>	cP	bbbl/STB	cP	PV/RT	ft <sup>3</sup> /scf	SCF/STB	Lb/lbmole	Air=1	dyne/cm	BTU/scf	lb/ft <sup>3</sup>
Stage#1	460	127	377.4	50.7	1.138	1.099	1.4E-02	9.2E-01	3.3E-02	343.60	24.57	0.85	16.08	1058.3	2.00
Stage#2	250	100	43.4	51.6	1.516	1.069	1.3E-02	9.4E-01	6.0E-02	40.60	25.46	0.88	18.50	1089.0	1.10
Stage#3	100	80	44	52.3	2.03	1.043	1.2E-02	9.7E-01	1.5E-01	42.20	28.93	1.00	20.50	1221.5	0.50
Stage#4	14.7	60	66.6	53.3	3.232	1	9.2E-03	9.9E-01	1.0E+00	66.60	40.97	1.41	22.22	2030.2	0.10

#### A.4 The Separation Test (ST)

The separation test is performed to simulate the separation process of the reservoir fluid when it is produced at the surface. The data obtained from this test help in the design of the optimal separator conditions for maximum amount of stock-tank oil recovery. With the PVT simulation, the procedure for performing the separation test is similar to that for the DL test except that the temperature in the separation test may vary from stage to stage. Table 8 presents the multistage separation test data.

#### A.5 VLE Details

The fluid equilibrium properties obtained at the bubble point conditions are presented in Table 9.

#### A.6 P-T Flash Calculation for the Reservoir Fluid

The P-T flash was performed at various combinations of constant pressure and temperature. The fluid properties obtained at these conditions are presented in Table 10.

**Table 9** Fluid properties at saturation condition ( $T = 127^{\circ}\text{F}$  and  $P = 1843$  psia) from VLE calculations

Property	Unit	Feed	Liquid	Vapor
Z-Factor	PV/RT		0.6970	0.8155
Viscosity	cP		0.6969	0.0182
MW	lb/lbmol	113.42	113.42	23.110
Volume	ft <sup>3</sup> /lbmol	2.3800	2.3800	2.7900
Density	lb/ft <sup>3</sup>	47.632	47.632	8.2950
Enthalpy	btu/lbmol	442.36	442.36	3851.2
Entropy	BTU/(lbmol F)	72.103	72.103	47.845
Heating Value	BTU/scf	6130.6	6130.6	983.16
Gibbs Energy	btu/lbmol	-38969.7	-38969.7	-19853.3
Volume %		100	100	0
Mol %		100	100	0
Light	Tc ≤ 88.0 F	0.357	0.357	0.8916
Intermediate	88.0 < Tc ≤ 460.0 F	0.2807	0.2807	0.1064
Heavy	Tc > 460.0 F	0.3623	0.3623	0.0019





**Table 10** Results of P–T flash calculation for reservoir fluid of JZR oil

Pressure	Temp.	Liquid	Liquid	Liquid	Liquid	Vapor	Vapor	Vapor	Vapor
Psia	F	Volume	Density	Viscosity	factor	Volume	Density	Viscosity	factor
		%	lb/ft <sup>3</sup>	cP		%	lb/ft <sup>3</sup>	cP	
1900	127	100	47.7	0.702	0.7181	0	0	0	0
1843	127	100	47.6	0.697	0.697	0	8.3	1.82E–02	0.8155
1600	127	92.94	48.1	0.734	0.6273	7.06	7.1	1.71E–02	0.8232
1400	127	85.85	48.5	0.772	0.5669	14.15	6.1	1.63E–02	0.833
1200	127	77.43	48.9	0.817	0.5034	22.57	5.2	1.56E–02	0.8458
1000	127	67.51	49.3	0.874	0.436	32.49	4.3	0.015	0.8617
800	127	55.99	49.8	0.947	0.364	44.01	3.4	1.44E–02	0.8804
600	127	42.91	50.3	1.044	0.2865	57.09	2.5	1.39E–02	0.9019
400	127	28.49	50.9	1.188	0.2022	71.51	1.7	1.34E–02	0.9266
200	127	13.4	51.7	1.434	0.1092	86.6	0.9	1.27E–02	0.9555
100	127	6.1	52.3	1.694	0.0581	93.9	0.5	1.22E–02	0.9729
60	127	3.39	52.8	1.916	0.0363	96.61	0.3	1.19E–02	0.9813
60	85	3.98	53	2.46	0.0371	96.02	0.3	1.15E–02	0.9806
14.7	60	0.89	54	4.337	0.0101	99.11	8.10E–02	1.05E–02	0.9932

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