DOI: 10.14621/ce.20160106

Application of Foamy Mineral Oil Flow under Solution Gas Drive to a Field Crude Oil

Bashir Busahmin[1]*, Brij Maini[2], Hossein Hejazi[2], Amin Sharifi[2], Mohammad Tavallali[3]

[1]Institut Teknologi Brunei-University
Jalan Tungku Link Gadong Brunei Darussalam, BE 1410; bashir.abusahmin@itb.edu.bn
[2]University of Calgary, Canada
[3]IHS, Canada

Abstract

Heavy oil flow in the form of foamy oil under solution gas drive is widely observed in many Canadian reservoirs. Despite the importance of such phenomenon, complexity involved in foamy oil flow in porous media is not well understood. Series of numerical simulations were performed to model experiments that were carried out in a two meter long Sand pack to investigate the conditions required to increase oil production under solution gas drive mechanism. Through these experiments the solution gas drive performance at different depletion rates were analyzed.

Creation of foamy heavy oil is thought to be responsible for higher recovery factors compared to what is expected from the conventional solution gas drive theory. However, the complex nature of foamy oil and different transport parameters are yet to be understood.The results of this study can be used to numerically model foamy-oil mechanism in heavy oil reservoirs. Furthermore, the results can be applied for reservoir production optimization as well as management.

A new model has been developed using commercial numerical simulator, computer modeling group, (CMG-STARS^{TM}). By using the experimental data, different experimental production histories have been matched. Effect of different parameters such as fluid and reservoir properties and depletion rate on foamy oil recovery have been evaluated. The results reveal that despite many difficulties, foamy oil flow through porous media can be numerically modeled. However these models will strongly depend on a good understanding of many different parameters including rock-fluid interaction, as well as the depletion rates.

Given the complex nature of such systems, this numerical model can be used to simulate and predict the oil and gas production from heavy oil reservoirs under foamy oil conditions.

Keywords:	Modelling and simulation; Multi-phase and multi fluid flows; Codes numeric and their developments and/or improvements

Article history:	Received:	08 July 2015
	Revised:	23 July 2015
	Accepted:	29 January 2016

1. Introduction

Foamy oil flow is a process which against many experimental and theoretical investigations still is not completely clear in many aspects [1, 2, 3, and 4]. An important question in foamy oil flow is whether or not the behaviour observed in the laboratory scale primary depletion tests can be simulated with available multi-phase flow simulators. Among the various commercial reservoir simulators, CMG-STARS^{TM} is considered the most versatile for modelling foamy oil flow. As discussed by Bayon et al. [5], it permits modelling of foamy flow by defining separate components to represent dissolved gas, dispersed gas, and the free gas. Artificial chemical reactions with associated reaction kinetics are defined to model the rate processes involved in formation of bubbles and separation of dispersed gas from the oil to form free gas [6, 7].

This manuscript presents the simulation model implemented in CMG-STARS^{TM} to history match the performed experimental results, and address the question of whether or not such commercial reservoir simulators can be used to history match foamy solution gas drive tests. An important idea in this context is to determine whether the simulation parameters tuned to history-match a specific experiment can truly represent the rock-fluid properties of the system, i.e. is it possible to simulate different depletion tests that have been ran under same rock-fluid system, with a unique set of parameters?

2. Reservoir simulation model

A one dimensional (1D) model was used to simulate the primary depletion tests using two types of methane saturated oils; mineral oil and crude oil. Since the sand-pack was placed horizontally for all the experimental runs, the flow direction is assumed to be horizontal. A

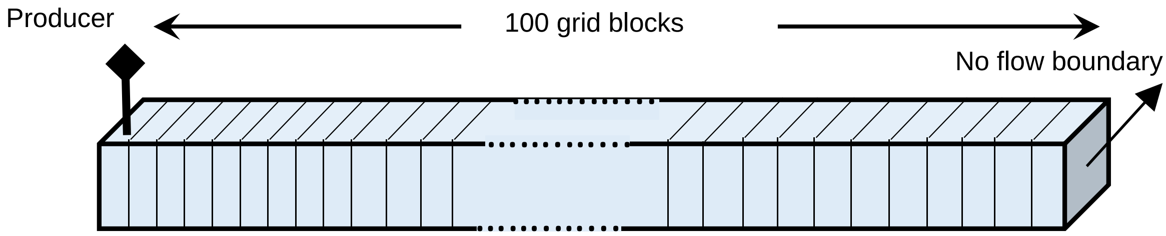

Figure 1: Schematic of simulation model

Table 1: Sand pack properties

Property	Value
Sand-pack length, cm	200
Cross-sectional area, cm^2	23.82
Pore volume, cm^3	1619.38
Porosity, %	34
Absolute permeability, Darcy	24
Overburden pressure, psi	1000
Sand grain size, mesh	30-50
Pore space compressibility, psi^{-1}	6.49×10^{-6}

Table 2: Dead oil properties

Property	Crude Oil	Mineral Oil
Density, kg/m^3	936	896
Viscosity at 21°C, cp	2800	1876
Viscosity at 40°C, cp	600	441
Viscosity at 50°C, cp	28	245
Molecular weight, kg/mol	800	700
Compressibility, psi^{-1}	6.9×10^{-6}	6.8×10^{-6}

Table 3: Fluid properties used in reservoir simulation

Property	Crude Oil-CH4	Mineral Oil-CH4
Live oil density, kg/m3	928	891
Live oil viscosity at 21◦C, 23◦C cp	1300	1080
Solution GOR, std. scm3/scm3	11	10
Density of gas at SC, g/cm3	0.00067832	0.00067832
Density of water at SC, g/cm3	1.070223	1.070223
Oil compressibility, 1/psi	4.37×10^{-6}	4.52×10^{-6}
Water formation volume factor	0.999305	0.999305
Water compressibility, 1/kPa	4.74×10^{-7}	4.74×10^{-7}
Water viscosity, cp	1.26459	1.26459
Initial pressure, psi	525	520
Bubble point pressure, psi	500	500

“producer” well was defined at one end of the model while the opposite end was a no-flow boundary. In the model, 100 grid blocks were defined along the length of the sand-pack. Therefore, the number of grid blocks in “X” direction is 100, and in “Y” and “K” directions are one. The average grid block size was about 2 cm by 4.88 cm by 4.88 cm. Figure 1 shows the schematic of the simulation model.

3. The analysis of a heat accumulator’s operation

The rock and fluid properties of the physical model that experiments were conducted are used in the numerical model as presented in Table 1 to 3. All the parameters such as porosity (34%) and permeability (24 Darcy) were kept constant for all depletion rate tests.

4. Pressure and production data

In the experiment, the pressure at the production well was set by the back-pressure regulator and was an independently controlled parameter. In the numerical model, the pressure at the production well of the sand-pack (P1) was considered the bottom hole production well pressure (BHP), which was entered into the simulator as an operating constraint. The oil and gas production data at different depletion rates were used in the history match analysis of the experiments.

5. Relative permeability curves

In order to achieve a reasonable history match for the primary depletion tests conducted at different depletion rates, the relative permeability curves had to be adjusted individually for each test. The relative permeability curves were based on Corey's exponent model for oil and gas as follows:

$$K_{rg} = K_{rg_{ro}} \left(\frac{S_g - S_{gc}}{1 - S_{or} - S_{gc} - S_{wc}}\right)^{N_g} \quad (1)$$

$$K_{ro} = K_{ro_{wc}} \left(1 - \frac{S_g - S_{gc}}{1 - S_{or} - S_{gc} - S_{wc}}\right)^{N_o} \quad (2)$$

$$K_{rw} = K_{rw_{ro}} \left(\frac{S_w - S_{or}}{1 - S_{or} - S_{gc} - S_{wc}}\right)^{N_w} \quad (3)$$

Table 4 presents the summary of the relative permeability and other parameters used for history matching the depletion tests. Also reaction rates for aggregation of dispersed gas to bubbles and then bubbles into free gas phase are also tuned in simulation model (RF1 and RF2 respectively)

6. Simulation results

Four depletion rates were designed for each oil type during experimental studies, which ranges from 0.021 to 0.434 psi/min. Table 4 shows different depletion rates as applied on the sand-pack. In order to model each test with multi-phase flow simulator relative permeability end points and exponents in the power-law model are used as matching parameters, and other parameters presented in Tables 1-3 are kept fixed with high level of confidence for their values. Figures 2 and 3 present the experimental and simulated values of cumulative oil production at different depletion rates for mineral oil. It is readily apparent that the simulated results can capture the general trend of oil production history and the final recovery values reasonable well.

The cumulative gas production for these four tests is compared in Figures 4 and 5. Here also the production trends and the final values are reasonably well matched. So, it is apparent that the simulation model can be tuned to provide decent matches of the cumulative production. However, the cumulative production often hides small differences in the behavior. The production rate is usually a more sensitive measure of the goodness of history matches. Figure 6 presents a comparison of the experimental and simulated oil rates for the fastest depletion.

The start of oil production is fairly well matched but the experimental data shows a much higher peak and faster decline. It was not possible to obtain a very good match between the experimental and simulated oil rates for this test. The gas rate match is shown in Figure 7. The gas rate was matched somewhat better than the oil rate. However, the simulated rate shows none of the wild swings in gas rate observed in the experiment.

Table 4: Summary of the parameters used for history matching the eight tests

Parameters	**Mineral Oil**				**Crude Oil**			
Depletion rate (psi/min)	0.406	0.247	0.086	0.021	0.434	0.226	0.048	0.023
Krwro	1	1	1	1	1	1	1	1
Krocw	0.128	0.05	0.008	0.003	0.18	0.043	0.007	0.001
Krgro	0.009	0.008	0.4	0.08	0.004	0.008	0.4	0.08
Krocg	1	1	1	1	1	1	1	1
Swcon	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Sgcon	0	0	0	0	0	0	0	0
Swc	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Sgc	0.02	0.05	0.05	0.04	0.025	0.025	0.05	0.04
Sorg	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Soirw	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Nw	2	2	2	2	2	2	2	2
No	2	2	2	2	2	2	2	2
Ng	1.5	2	2.5	2	2	2	3	2
RF1	0.019986	0.009993	0.00045	0.000138	0.018986	0.0001978	0.00025	0.000147
RF2	0.00095	0.00048	0.00045	0.00037	0.00085	0.0007	0.00045	0.0004

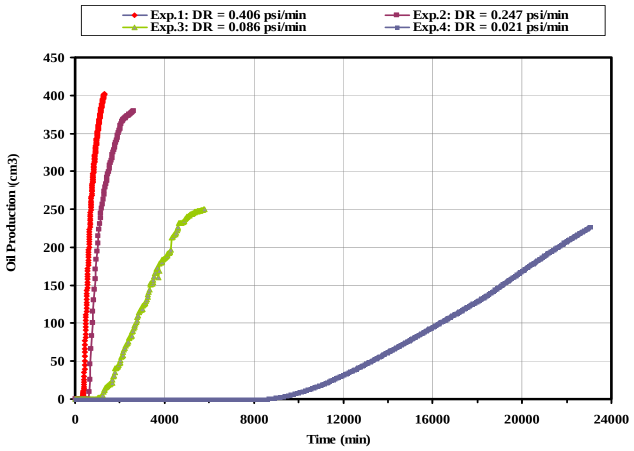

Figure 2: Experimental cumulative oil production versus time for depletion tests at different rates with methane saturated mineral oil at room temperature, and at 3447 kPa

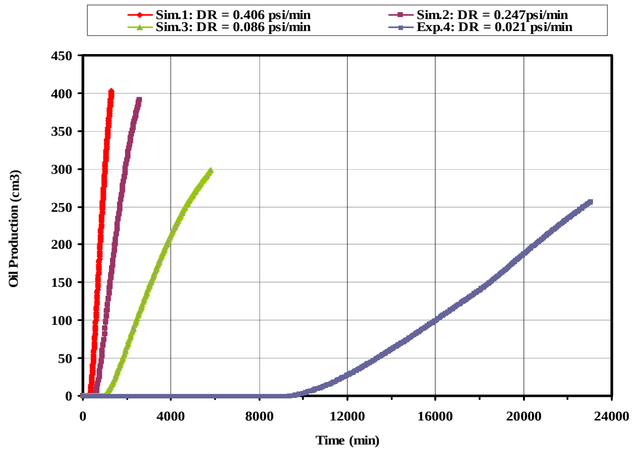

Figure 3: Simulation of cumulative oil production against time for depletion tests at different rates with methane saturated mineral at room temperature, and at 3447 kPa

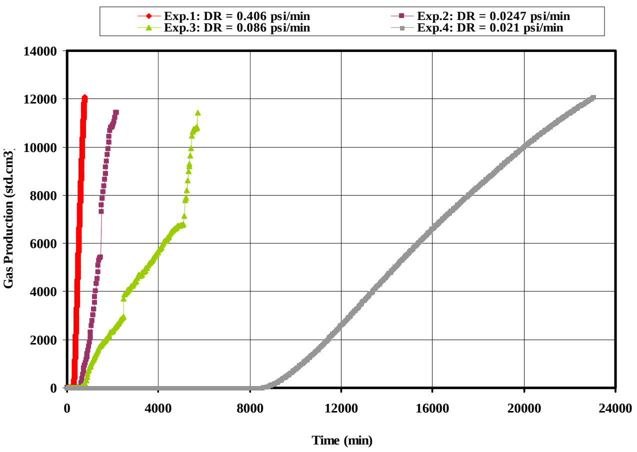

Figure 4: Experimental cumulative gas production against time for methane saturated mineral oil at room temperature, and at 3447 kPa

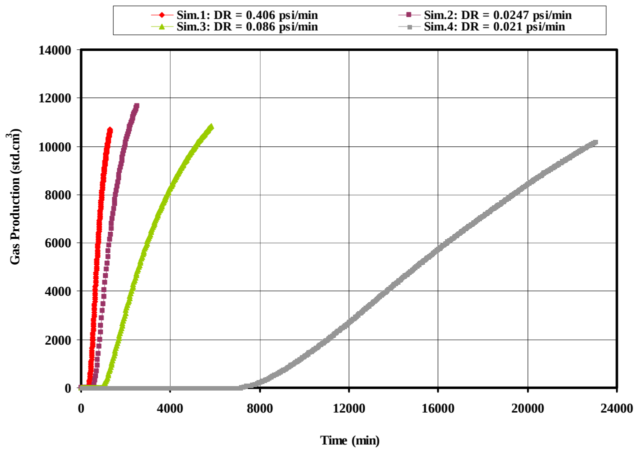

Figure 5: Simulation of cumulative gas production against time for methane saturated mineral oil at room temperature, and at 3447 kPa

Figure 6: Typical oil production rate vs. time for very fast depletion test for methane saturated mineral oil system

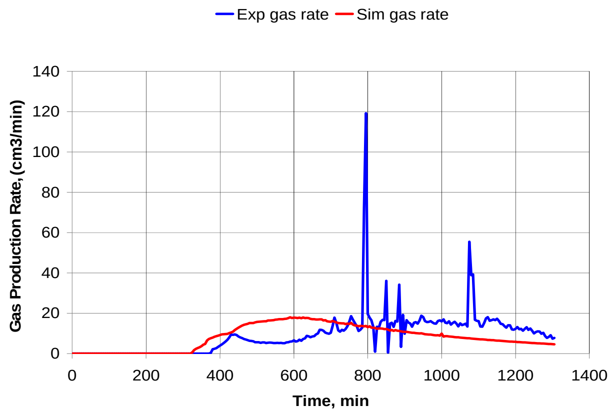

Figure 7: Typical gas production rate vs. time for very fast depletion test for methane saturated mineral oil system

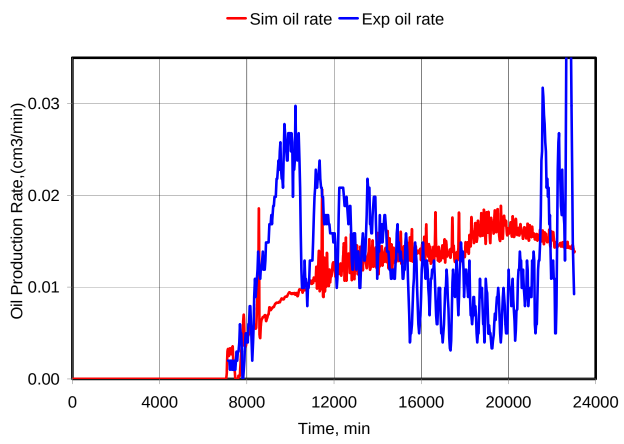

Figure 8: Oil production rate against time for a slow depletion test – methane saturated mineral oil system

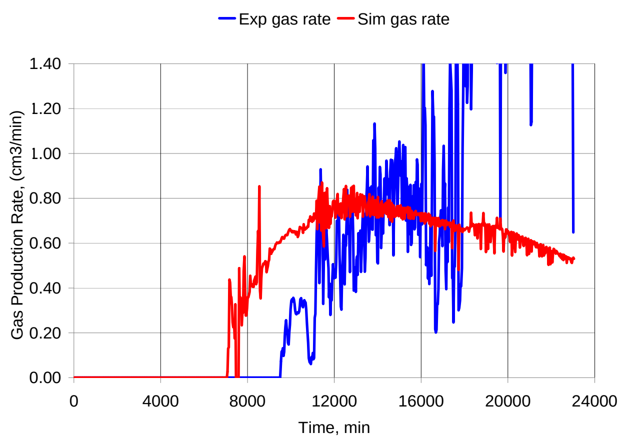

Figure 9: Gas production rate vs. time for slow depletion test – methane saturated mineral oil

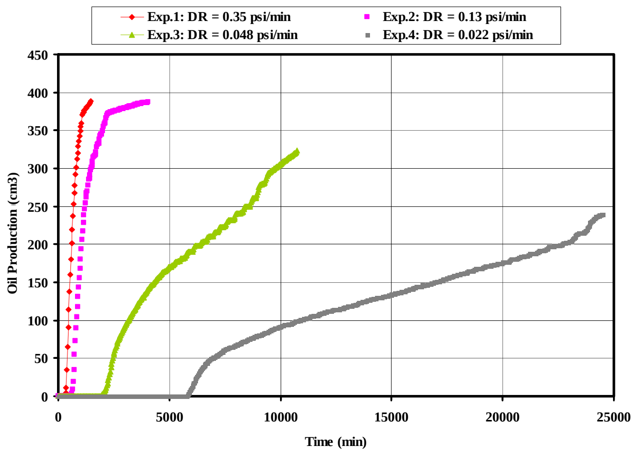

Figure 10: Experimental Cumulative of oil production against time for methane saturated crude oil at room temperature, and at 3447 kPa

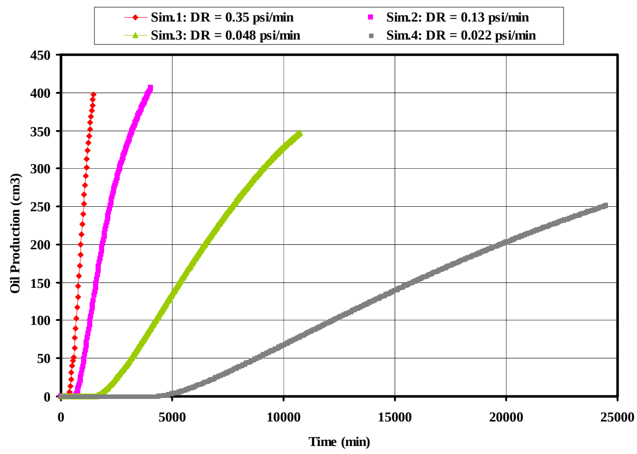

Figure 11: Simulation of cumulative oil production against time for methane saturated crude oil at room temperature, and at 3447 kPa

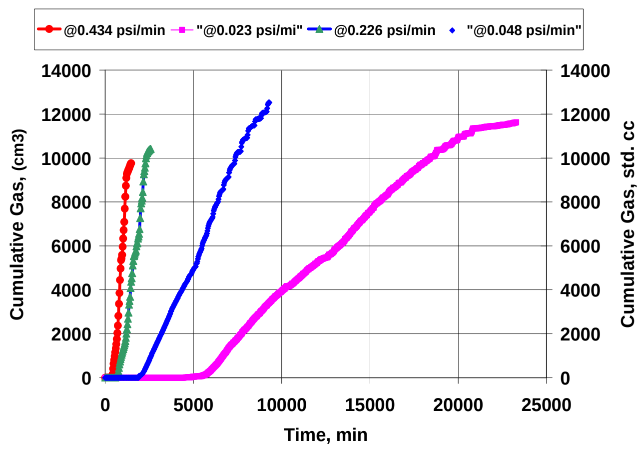

Figure 12: Experimental of cumulative gas production against time for methane saturated crude oil at room temperature, and at 3447 kPa

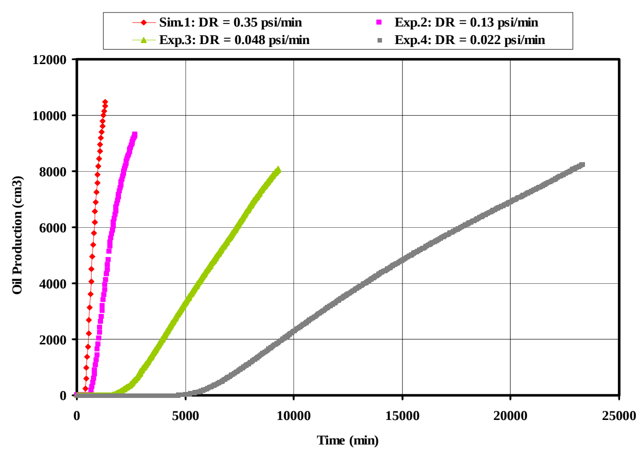

Figure 13: Simulation of cumulative gas production against time for methane saturated crude oil at room temperature, and at 3447 kPa

Figure 8 shows the oil rate history match of a slow depletion in the mineral oil-methane system. The oil rate match is somewhat better in the slow depletion. The gas production rates are compared in Figure 9. Here the match is not as good. So, in general, it is extremely difficult to get very good history match for oil and gas production rates, even though the cumulative production history can be reasonable well matched. It should also be mentioned here that different simulation parameters had to be used to get the matches shown here. These included different relative permeability end-points and different rate constants.

In general it is not possible to history match experiments done at different rates with the same set of rock-fluid properties and rate constants. Therefore, the simulation parameters obtained by history matching a specific experiment cannot be used for predicting the behavior of depletions involving substantially different operating conditions.

Figures 10-13 present the experimental and simulated oil and gas production histories of the four solution gas drive tests carried out with the crude oil system. Here also, it was not difficult to obtain reasonable histories matches for the cumulative oil and gas productions. However, the real test of the history match is in comparing the rates of oil and gas production.

The experimental and simulated oil production rates for the fastest depletion are compared in Figure 14. As in the case of mineral oil, the high peak in oil production rate observed in the experiment is not well matched by the simulation. The oil rate declines more rapidly in the experiment than in the simulation. The gas production rates are compared in Figure 15. The gas rates are quite well matched. The matches for the slow experiments are shown in Figure 16-17. Here the matches are quite good except that the experimental profiles show lot more fluctuations.

Therefore it can be stated that it is possible to obtain reasonably good history matches by tuning the rock-fluid parameters. However, with crude oil also, tests carried out at different depletion rates required different rock-fluid parameters. This limits the usefulness of such history matching in using the laboratory experiments to predict the field scale behavior. This is due to the complexity of the foamy oil flow in porous media which involves bubbly oil flow and sand production and cannot be easily modeled such as conventional oil reservoirs. It suggests more investigation is needed to understand the foamy oil flow to model the physics of the process.

7. Conclusions

This paper presents the conclusions drawn from the simulation of primary depletion tests conducted in a two-meter long sand-pack to study the effects of several variables that influence foamy oil flow under solution gas drive. Conclusions drawn from the limited simulation work carried out to history match several depletion tests are also included.

1. The solution gas drive performance in all systems declined with decreasing rate of pressure reduction at the production end.
2. The solution gas drive recovery factor, in heavy oil systems, depends strongly on the pressure drawdown (as the driving force for the oil production) that develops in the system as a result of pressure reduction or fluid withdrawal at the production port.

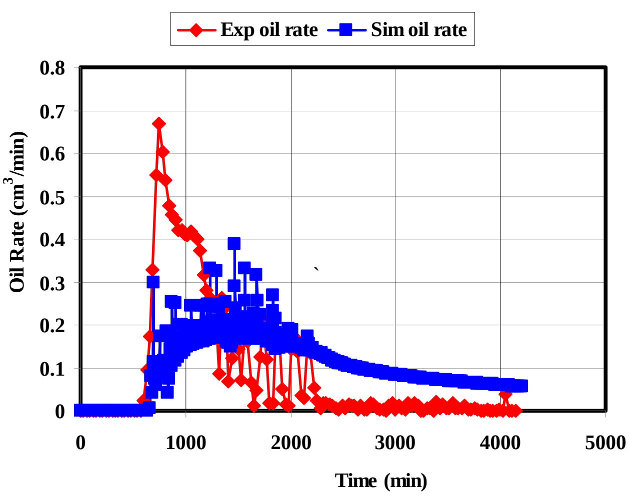

Figure 14: Oil production rate versus time for a fast depletion test for methane saturated crude oil system

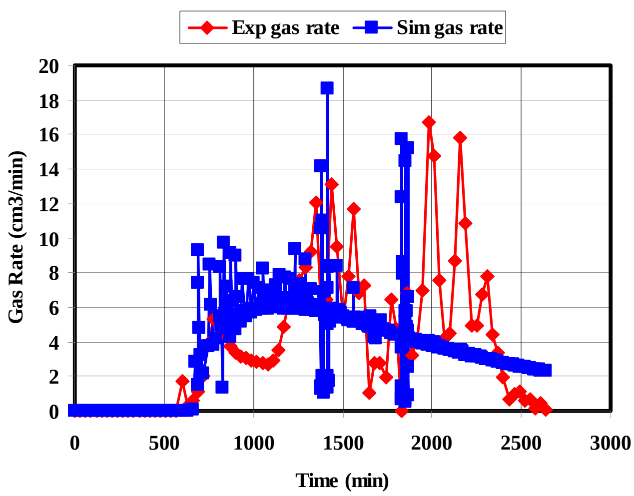

Figure 15: Typical gas production rate vs. time for fast depletion test for methane saturated crude oil system

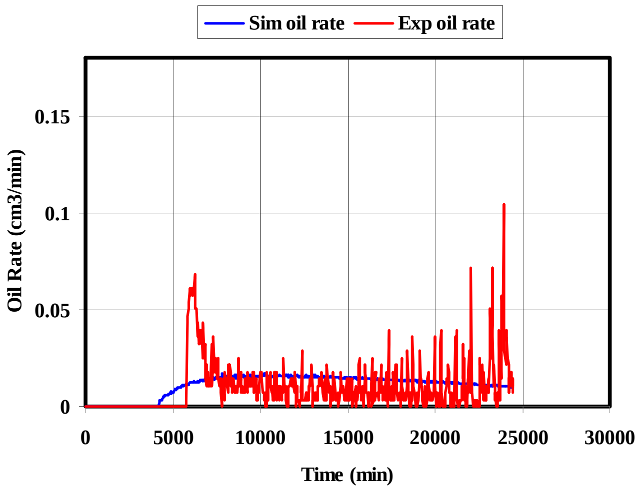

Figure 16: Oil production rate against time for a slow depletion test – methane saturated crude oil system

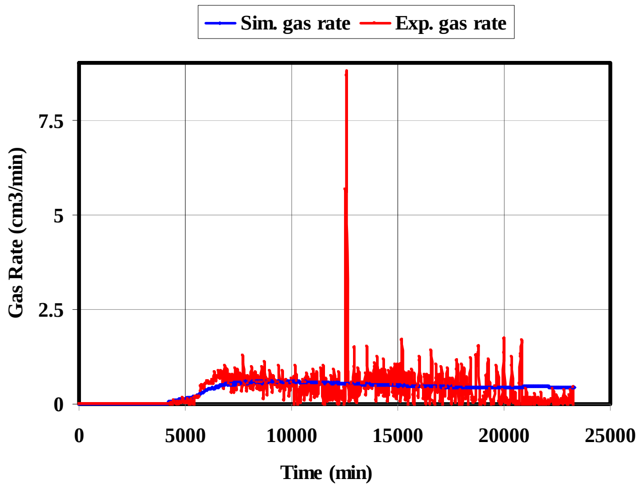

Figure 17: Gas production rate against time for slow depletion test – methane saturated crude oil

3. The foamy solution gas drive performance is negatively affected by increased solution gas-oil-ratio.
4. Both mineral and crude oil systems displayed similar decline in the oil recovery performance with decreasing rate of pressure depletion.
5. Foamy solution gas drive simulation parameters tuned by history matching a specific experiment do not provide good history matches of other experiments carried out at different rates in the same rock-fluid system.

References

[1] Albartamani, N.S., Farouq Ali, S.M., and Lepski, B., Investigation of Foamy Oil Phenomena in Heavy Oil Reservoirs, *Proceedings*, International Thermal Operation/Heavy Oil Symposium, 17-19 March, Bakersfield, California, USA, 1999, SPE 54084.

[2] Arora, P., Kovscek, A. R., Mechanistic Modeling of Solution Gas Drive in Viscous Oils, *Proceedings*, SPE International Thermal Operations and Heavy Oil Symposium, 12-14 March, Porlamar, Margarita Island, Venezuela, 2001, SPE 69717.

[3] Alicia, N. Ostos, Effect of capillary Number on Performance of Solution Gas Drive in heavy oil Reservoirs, Master Thesis, Chemical and Petroleum Engineering, University of Calgary, Calgary, Canada, 2003.

[4] Andarcia, L., Kamp, A.M., Vaca, P., Heavy Oil Solution Gas Drive in the Venezuelan Orinoco Belt: Laboratory Experiments and Field Simulation, *Proceedings*, SPE International Thermal Operations and Heavy Oil Symposium, 12-14 March, Porlamar, Margarita Island, Venezuela, 2001, SPE 69715.

[5] Bayon, Y.M., Cordelier, Ph.R., Coates, R.M., Lillico, D.A., Sawatzky, R.P., Application and Comparison of two Models of Foamy oil Behavior of Long core Depletion Experiments, *Proceedings*, SPE International Thermal Operation and Heavy Oil Symposium and International Horizontal Well Technology Conference, 4-7 November, Calgary, Alberta, Canada, 2002, SPE 78961-MS.

[6] Bayon, Y. M., Cordelier, Ph.R., Nectoux, A., A New Methodology To Match Heavy-Oil Long – core Primary Depletion Experiments, *Proceedings*, SPE/DOE Improved Oil recovery Symposium, 13-17 April, Tulsa, Oklahoma, USA, 2002, SPE 78961.

[7] Bondino, I., MacDougall, S.R., Hamon, G., Pore Network Modelling of Heavy Oil Depressurisation: a Parametric Study Affecting critical Gas Saturation and 3-phase Relative Permeability, *SPE Journal*, 10, 2005, 2, doi, http://dx.doi.org/10.2118/78976-PA