Performance of Drainage Experiments With Orinoco Belt Heavy Oil in a Long Laboratory Core in Simulated Reservoir Conditions

Ruihe Wang and **Jishun Qin,** China National Oil and Gas Exploration and Development Corporation; **Zhangxin Chen,** Department of Chemical and Petroleum Engineering, University of Calgary; and **Ming Zhao,** China National Petroleum Corporation

Summary

When some heavy-oil reservoirs are produced using gas drive, they show three important features: low production gas/oil ratios, higher-than-expected production rates, and relatively high oil recovery. The mechanism for this unusual behavior remains controversial and poorly understood, though the term "foamy oil" is often used to describe such behavior. The impetus for this work stems from some recent projects performed in the Orinoco belt, Venezuela. There exist nearly one trillion bbl of heavy oil (oil in place) in this region on the basis of a recent evaluation. Two crucial issues must be addressed before or during designing production projects: What is a suitable method for evaluating the foamy-oil drive mechanism that plays a major role during such oil recovery, and how do we obtain a reasonable percentage of ultimate oil recovery? Unfortunately, it is still difficult to give good explanations for these two issues, although several studies were performed. This paper attempts to present better explanations for these two issues using experimental drainage in a long laboratory core in simulated reservoir conditions.

Our experiments show that ultimate oil recovery for the heavy oil in the Orinoco belt can be as high as 15–20%. This high recovery comes from three contributions: fluid and rock expansion, foamy-oil drive, and conventional-solution-gas drive. Approximately 3–5% of recovery is from fluid and rock expansion, 11–16% from foamy-oil drive, and 2–4% from conventional-solution-gas drive. This ultimate-oil-recovery percentage is much higher than the 12% that has been used in the field-development plan for the Orimulsion project. The experiments performed and their findings obtained in this paper are representative at least in the Orinoco belt region.

Introduction

Most practitioners try to produce as much oil as possible under primary recovery. In all solution-gas-drive reservoirs, gas is released from solution as the reservoir pressure declines. Gas initially exists in the form of small bubbles created within individual pores. As time evolves and pressure continues to decline, these bubbles grow to occupy the pores. With a further decline in pressure, the bubbles created in different locations become large enough to coalesce into a continuous gas phase. Conventional wisdom indicates that the discrete bubbles that are larger than pore throats remain immobile (trapped by capillary forces) and that gas flows only after the bubbles have coalesced into a continuous gas phase. Once the gas phase becomes continuous, which is equivalent to the gas saturation becoming larger than critical, the minimum saturation at which a continuous gas phase exists in porous media (Chen et al. 2006), traditional two-phase (gas and oil) flow with classical relative permeabilities occurs. A result of this evolution process is that the production gas/oil ratio (GOR) increases rapidly after the critical gas saturation has been exceeded.

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Field observations in some heavy-oil reservoirs, however, do not fit into this solution-gas-drive description in that the production GOR remains relatively low. The recovery factors (percentage of the oil in a reservoir that can be recovered) in such reservoirs are also unexpectedly high. A simple explanation of these observations could be that the critical gas saturation is high in these reservoirs. This explanation cannot be confirmed by direct laboratory measurement of the critical gas saturation. An alternative explanation of the observed GOR behavior is that gas, instead of flowing only as a continuous phase, also flows in the form of gas-in-oil dispersion. This type of dispersed gas/oil flow is what is referred to as "foamy-oil" flow.

Although the unusual production behavior in some heavy-oil reservoirs was observed as early as the late 1960s, Smith (1988) appears to have been the first to report it and used the terms "oil/gas combination" and "mixed fluid" to describe the mixture of oil and gas that is entrained in heavy oil as very tiny bubbles. Baibakov and Garushev (1989) used the term "viscous-elastic system" to describe highly viscous oil with very fine bubbles present. Sarma and Maini (1992) were the first to use the phrase "foamy oil" to describe viscous oil that contains dispersed gas bubbles. Claridge and Prats (1995) used the terms "foamy heavy oil" and "foamy crude." Although there is continuing debate on the suitability of the term "foamy-oil flow" to describe the anomalous flow of the oil/gas mixture in primary production of heavy oil (Firoozabadi 2001; Tang and Firoozabadi 2003; Tang and Firoozabadi 2005), this expression has become a fixture in the petroleum-engineering terminology (Chen 2006, Maini 1996).

The actual structure of foamy-oil flow and its mathematical description are still not well understood. Much of the earlier discussion of such flow was based on the concept of microbubbles [i.e., bubbles much smaller than the average pore-throat size and, thus, free to move with the oil during flow (Sheng et al. 1999)]. This type of dispersion can be produced only by nucleation of a very large number of bubbles (explosive nucleation) and by the presence of a mechanism that prevents these bubbles from growing into larger bubbles with decline in pressure (Maini 1996). This hypothesis has not been supported by experimental evidence.

A more plausible hypothesis on the structure of foamy-oil flow is that it involves much larger bubbles migrating with the oil and that the dispersion is created by the breakup of bubbles during their migration with the oil. The major difference between the conventional-solution-gas drive and the foamy-solution-gas drive is that the pressure gradient in the latter is strong enough to mobilize gas clusters after they have grown to a certain size. Maini (1999) presented experimental evidence that supports this hypothesis for foamy-oil flow. This hypothesis seems consistent with the visual observations in micromodels that show the bubble size to be larger than the pore size. However, more laboratory experiments must be conducted to validate this hypothesis.

The impetus for this work stems from some recent projects performed in the Orinoco belt, Venezuela. The largest heavy-oil reserves in the world are in this region, with nearly one trillion bbbl of heavy oil in place on the basis of a recent evaluation

(Fig. 1) (Andarcia et al. 2001). The unusual recovery performance mentioned previously has been observed during drainage of heavy-oil reservoirs in the Orinoco belt. The problems we now face are the following.

How will we estimate the production performance for the present project by taking into account the foamy-oil-drive mechanism? In addition, what will be an applicable measure to evaluate the production potential of this project?

What will a production profile of this project look like? How much oil will be produced within a certain time period of our operation?

Unfortunately, there were no satisfactory answers yet for these questions. This paper attempts to address these issues using results from a suite of laboratory experiments. The attempts to address these issues will improve our understanding of foamy-oil behavior and its mechanism.

On the basis of our laboratory analysis, there are two bubblepoint pressures in the foamy oil of the Orinoco belt: One is the true bubblepoint pressure (the traditional equilibrium bubblepoint pressure), and the other is the pseudobubblepoint pressure. According to its definition, the true bubblepoint pressure is the pressure at which bubbles start to generate in the oil phase. The pseudobubblepoint pressure is the pressure at which bubbles in the oil phase start to coalesce to form a continuous gas phase. The greater the difference between these two pressures, the greater the contribution to oil recovery from the foamy-oil-drive mechanism. Therefore, it is important to determine the exact magnitude of the pseudobubblepoint pressure.

The objectives of our experiments in this paper are

- To acquire the pseudobubblepoint pressure
- To understand the foamy-oil contribution to oil recovery
- To obtain an actual percentage of primary recovery for heavy-oil reservoirs in the region under consideration

The procedures of our experiments are

- Sampling live oil (formation oil) by combining tank oil and apparent solution gas that was obtained on the basis of information from a fully compositional analysis of the in-situ solution gas
- Making an artificial long laboratory core based on properties of the formation because the formation itself is completely unconsolidated
- Repeating experiments of constant-volume drainage in formation conditions with the artificial core after it is saturated with live oil to acquire performance that includes oil, gas, and pressure profiles vs. time or recovery.

Most published papers on heavy oil, particularly on foamy oil in the Orinoco belt (Layrisse 1999, Marruffo and Sarmiento 2000), have concentrated on finding out how it happened (e.g., understanding the evolution of bubbles in oil during formation-pressure depletion—that is, trying to unveil the conditions under which foamy oil may occur). This paper focuses on the investigation of what the performance is when the foamy-oil flow occurs in a porous medium and on the study of how it affects the procedure of oil recovery by three-stage profiles obtained from constant-volume depletion of a long core with simulated reservoir conditions. Our experiments show that ultimate oil recovery for the heavy foamy oil in the Orinoco belt can be as high as 15–20%. This high recovery comes from three contributions: fluid and rock expansion (3–5%), foamy-oil drive (11–16%), and conventional-solution-gas drive (2–4%). This ultimate oil-recovery percentage is much higher than the 12% that has been used in the field-development plan for the Orimulsion project. We emphasize that instead of saturating the oil with gas (Kraus et al. 1993, Maini 1999), in the present depletion experiments, natural gas with fully compositional information is used. Also, in the area under study, there is no way to obtain a solid core because the targeted formation is completely unconsolidated. The core used in our experiments is made of sand according to the formation properties (the size of sand, porosity, and permeability). Unconsolidated formation always shows more compressibility than consolidated formation, which contributes to the higher-than-usual recovery in the first stage.

The paper is organized as follows. In the next section, we present a live-oil pressure, volume, and temperature (PVT) analysis. In the third section, we report our depletion experiments. In the fourth section, we analyze our experimental results. In the last section, we give concluding remarks.

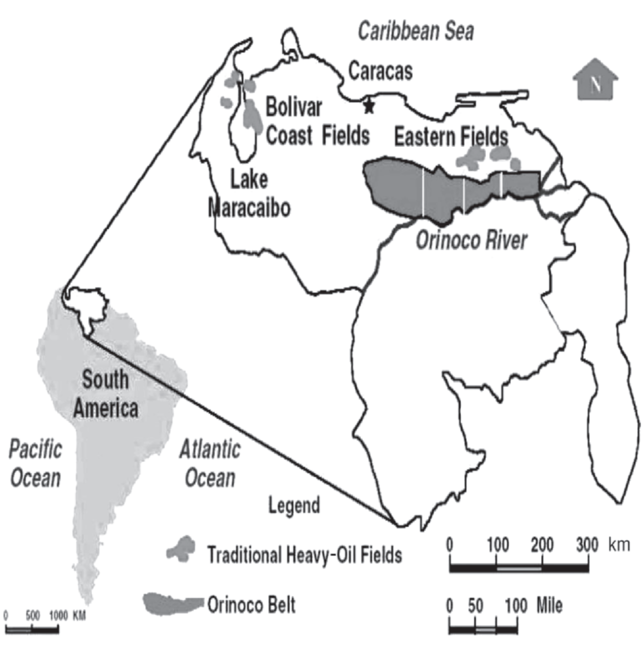

Fig. 1—The Orinoco belt in Venezuela.

Live-Oil PVT Analysis

As noted in the previous section, foamy-oil behavior is a unique feature associated with primary production of heavy oil. It is believed that this mechanism contributes significantly to the unusual high production rates of heavy crudes observed in many heavy-oil reservoirs. This paper describes our experimental samples and procedures used to characterize the Orinoco-belt heavy oil that is representative, at least, among the heavy-oil-production applications in Venezuela.

According to an earlier preliminary study (Kraus et al. 1993) and the present study, the basic mechanism of foamy-oil behavior is related to the existence of a pseudobubblepoint pressure. The true bubblepoint pressure is the pressure at which the first small bubbles of free gas evolve from solution and nucleate as a distinct gas phase in reservoir conditions. For most conventional oils, the gas rapidly coalesces into large bubbles and evolves almost immediately from the oil to become a separate free-gas phase. In many petroleum reservoirs, this phenomenon forms a secondary gas cap during depletion operations and leads to high GORs at production wells because of the high mobility of the free-gas phase.

For foamy oils, because of their high viscosity, the gas bubbles cannot immediately coalesce to form bubbles large enough to allow gravitational forces to separate them from the oil. For this reason, the oil phase remains as a continuous dispersed gas/oil emulsion with a higher concentration of increasingly larger bubbles trapped within the oil even with pressure declining. The pressure at which the gas bubbles finally can begin to escape from solution as a separate free-gas phase is the pseudobubblepoint pressure. Therefore, it is important to determine the exact magnitude of this pressure.

It was observed that, if tank oil is exposed in standard conditions for a long time, most light and some medium components in the oil vaporize. Hence, artificial samples obtained only from a combination of tank oil and solution gas cannot be a good match with formation oil, and it is absolutely necessary to perform a PVT analysis on live samples.

Clean Orinoco-belt-reservoir crude oil at a reservoir temperature of 60°C is used to perform a fully compositional analysis. Earlier experimental samples for primary-depletion tests used recombined oil by saturating the oil with gas (Kraus et al. 1993, Maini 1999). In the present depletion experiments, natural gas with fully compositional information is used. Three samples are pre-

TABLE 1—PVT ANALYSIS OF THE SAMPLES

Samples	Sample 1.01	Sample 1	Sample 2
Laboratory	Schlumberger	RIPED	RIPED
Bottomhole pressure (MPa)	5.22	–	–
Depth (m)	612.9	–	–
Temperature (°C)	60	60	60
Density of dead oil (g/cm^3)	1.0126	1.0162	0.9971
GOR (m^3/m^3)	16	15.9	18.1
Bubblepoint pressure (MPa)	5.67	7.95	7.03
C_1 + N_2 (mol%)	22.56	20.97	20.68
C_2 to C_{10} (mol%)	1.84	0.51	8.16
C_{11}+ (mol%)	72.81	75.84	68.62
C_{30}+ (mol%)	33.76	29.94	23.39
C_{58}+ (mol%)	–	14.22	12.86
Viscosity (mPa·s, in formation)	–	1,583	476
Viscosity (mPa·s, in atmosphere)	–	6,194	1,376
Remark	Sample from formation	Combination of tank oil and solution gas	Combination added 10% kerosene

pared for the analysis **(Table 1);** the first one is a Schlumberger sample, and the other two are prepared by us (Sample 1 and Sample 2). From our sample analysis, we have obtained the following observations:

- Chemical components C_1–C_{10} have gone from the tank oil, which means that all light and most medium components in the tank oil have disappeared.
- The first sample (Sample 1) obtained from combining tank oil and solution gas has lost components C_2–C_{10}, as compared with the sample from the formation. It is expected that the best-matched sample with the sample from the formation can be achieved by adding a certain amount of kerosene to compensate for the lost medium components, which cannot be satisfied by solution gas.
- Components C_2–C_{10} have a significant impact on the bubblepoint pressure.
- The sample from the formation may not completely reflect live oil in the formation because the sampling pressure is lower than the actual formation pressure.

The recombined sample with tank oil, separator gas, and kerosene should have the critical feature: Its properties comply with the properties of the reservoir oil, such as the relative volume, viscosity, and gas solubility, which are more important than others because they play a dominant role in determining the performance of oil recovery. Comparisons of these PVT properties between the fluid from the reservoir and the recombined samples are shown in **Figs. 2 through 4,** respectively. Although there are slight differences among them, it is acceptable from a practical point of view.

Depletion Experiments

The objectives of our primary-depletion experiments are to determine the pseudobubblepoint pressure, understand the foamy-oil contribution to oil recovery, and obtain an actual percentage of primary recovery for the heavy-oil reservoirs under consideration. A schematic of the experimental equipment is shown in **Fig. 5.** The experimental procedure is prepared as follows:

- Making an artificial core for the experiments with 20% 40/60-mesh quartz sand, 60% 60/80-mesh, and 20% 80/120-mesh. Because the targeted formation consists of completely unconsolidated sand, it is more convenient to measure the sand size than the pore size. The artificial core used in our laboratory was constructed on the basis of information on formation-sand size, permeability (k), and porosity (ϕ), which are given in **Table 2.**
- Making artificial live oil at a temperature of 60°C and a pressure of 20 MPa, and preparing a tank-oil mixture with solution gas according to the GOR. The effectiveness of the gas Z factor should be calculated when a gas volume is estimated (Qin and Li 2004, Sun 1992). The gas volume in standard conditions can be derived by the formula

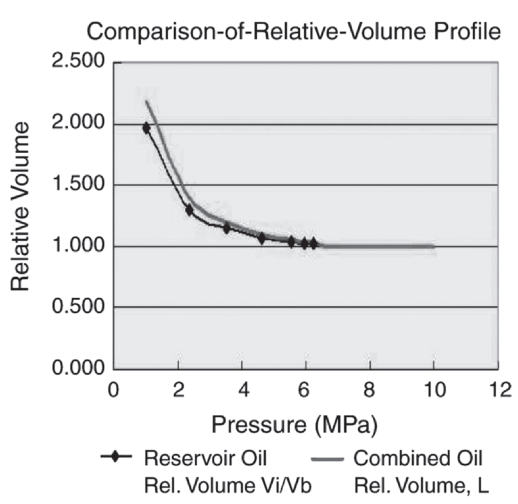

Fig. 2—Comparison of relative volumes between the recombined and reservoir examples.

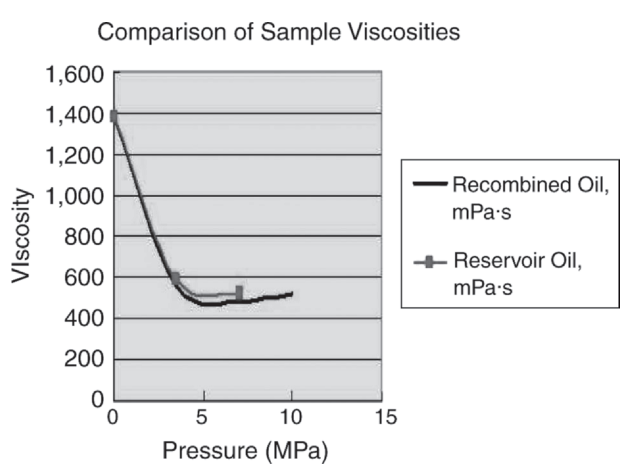

Fig. 3—Comparison of viscosities (mPa·s) between the recombined and reservoir examples.

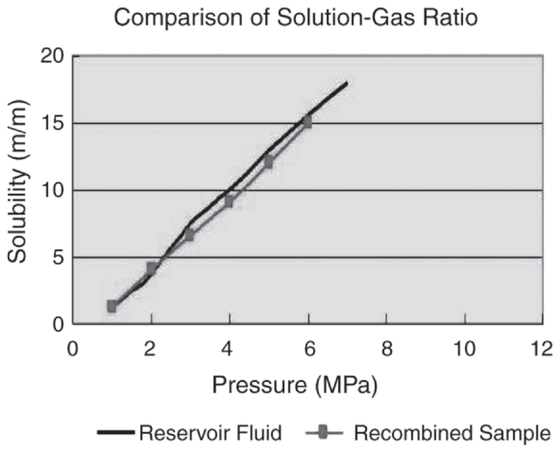

Fig. 4—Comparison of gas solubilities between the recombined and reservoir examples.

$$V_0 = \frac{P_1 V_1}{P_0 Z}, \quad \text{(1)}$$

where P_0 is the atmospheric pressure (0.1 MPa), V_0 is the gas volume in standard mL, P_1 is the pressure (MPa) in the container, V_1 is the container volume (mL), and Z is the gas factor at pressure P_1.

• Checking the GOR of the artificial samples. The true bubblepoint pressure and the pseudobubblepoint pressure are observed by tracking the GOR. Between the true and pseudobubblepoints, the evolved gas remains trapped in the in-situ and expelled oil.

• Calculating the pseudobubblepoint pressure of the artificial samples. Upon reaching the pseudobubblepoint, free gas evolves out of the oil and starts to become trapped in the pore-system matrix to build up a trapped-gas saturation. This implies that the GOR of the effluent fluid should actually drop for a short period as the somewhat-depleted oil is forced from the pore system, while the liberated free gas builds up the in-situ trapped-gas critical saturation.

• Once the critical gas saturation is achieved, free gas becomes mobile. This can be observed by an increase in the GOR of the produced fluid as free mobile gas is produced.

We remark that the temperature of the experimental system is increased to the reservoir temperature of 60°C after the core properties are measured and the core is saturated with live oil. Then, the inlet valve of the core is shut down, and the depletion experiments are started.

Experimental-Results Analysis

Fluid produced from the system is separated into tank oil and natural gas that will be scaled by balance and gas meter, respectively. Parameters for the experimental system are shown in **Table 3,** where S_o, S_{wim}, and p_b stand for the oil saturation, initial water saturation, and bubblepoint pressure, respectively. The objective of this suite of experiments is to analyze the performance of GOR and oil recovery vs. the system pressure. They can be used to find

• Recovery of oil in place as a function of pressure

• Pressure at which the critical trapped-gas saturation begins to be produced

• Pressure at which the mobile-gas saturation is achieved.

Oil recovery can be computed from the following formula:

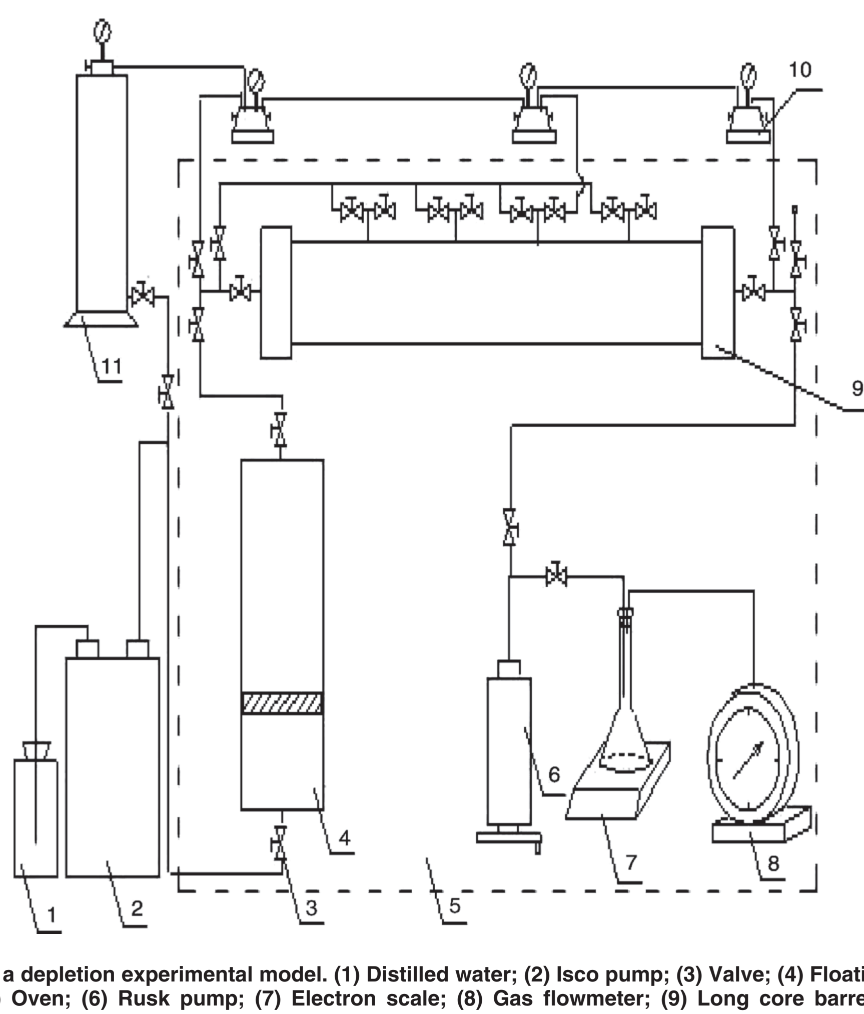

Fig. 5—Flow chart of a depletion experimental model. (1) Distilled water; (2) Isco pump; (3) Valve; (4) Floating-piston accumulator for formation oil; (5) Oven; (6) Rusk pump; (7) Electron scale; (8) Gas flowmeter; (9) Long core barrel; (10) Multivalve; (11) Floating-piston accumulator.

TABLE 2—SAND SIZE, PERMEABILITY, AND POROSITY FOR ARTIFICIAL CORE QUARTZ SAND % (WT)

Sample	20 (mesh=m)	40 (m)	60 (m)	80 (m)	120 (m)	160 (m)	Total	k (darcies)	ϕ (%)
Real	23	17	27	19	11	3	100	15	36.3
Artificial	25	15	25	25	10		100	14.7	37

$$\eta = \frac{V_{\text{produced tank oil}}}{V_{\text{total oil saturated}}} \quad \ldots\ldots (2)$$

The GOR- and recovery-vs.-pressure curves are displayed in **Fig. 6.** According to the three linear trends in the oil-recovery profile shown in this figure, it is reasonable to believe that these trends reflect three different depletion stages. The intersection of the first and second trends indicates the bubblepoint pressure, and the intersection of the second and third trends gives the pseudobubblepoint pressure.

In the first depletion stage, fluid is produced by the fluid and core expansion while pressure declines from the original level down to the bubblepoint (approximately 8.5 Mpa). The fluid remains as a single liquid phase, with oil recovery at 3–5%. As noted in the Introduction, in the area under study, there is no way to obtain a solid core because the targeted formation is completely unconsolidated. The core used in our experiments is composed of sand on the basis of the formation properties (the size of sand, porosity, and permeability). Unconsolidated formation always shows more compressibility than normal formation, which contributes to the higher-than-usual recovery in the first stage.

In the second stage, tiny gas bubbles leave the oil when the pressure drops below the bubblepoint pressure. The bubbles disperse in the oil rather than coalesce to form a continuous gas phase that would lead to gas breakthrough and make the formation lose energy and decrease oil production. The oil with dispersed bubbles is foamy oil, as noted, which provides tremendous energy to the formation to prevent pressure and oil production from declining. The foamy oil is produced until the bubbles grow large enough to coalesce to form a continuous gas phase; the pressure at this moment is the pseudobubblepoint pressure (approximately 4.7 Mpa). Recovery can be more than 12% in this stage, in the region under consideration. This suggests significant effects of foamy oil.

In the third stage, gas is developed from the dispersed phase into a continuous phase that moves in its own channel in the core much faster than oil because it has a much greater mobility than oil, which results in gas breakthrough and dramatically increases the production GOR. Incremental oil recovery is approximately 2% in this stage, for the region under consideration.

The constructed sample with 10% kerosene has a better PVT match from the reservoir-fluid-PVT analysis, and the performance of experiments with this sample reflects the reservoir more accurately. Therefore, only this test is presented in Fig. 6.

Conclusions

From our experiments and their analysis we conclude that

- Foamy-oil phenomena indeed exist during the development of the Orinoco belt heavy oil in Venezuela because of the high bubblepoint pressure and solution GOR and the special properties of the oil.
- Foamy oil apparently prevents gas bubbles from forming a continuous gas phase and breaking through, which would cause a great loss of formation energy and, in turn, ultimately reduce oil recovery.
- Foamy-oil phenomena play a major role in the natural depletion of heavy-oil reservoirs in the Orinoco belt in Venezuela. The contribution to oil recovery from the foamy-oil drive mechanism can be up to 12% of oil in place. The total ultimate oil recovery can be expected to be 20% of oil in place.
- Our experimental results are based on ideal conditions; for example, the effect of sweep efficiency is almost neglected, so the conditions are optimized. Real practice of developing oil in this area may not be expected to gain such high recovery.

Because the Orinoco belt in Venezuela holds some of the largest heavy-oil reserves, the experimental studies performed in this paper will tremendously help the design of development and production projects in this region. Our experiments are the first attempt to study the effect of the foamy-oil behavior on the procedure of oil recovery by three-stage profiles obtained from constant-volume depletion of a long core under conditions simulating reservoir conditions in the Orinoco belt. To date, a mathematical model of foamy-solution-gas drive that incorporates the physics of generation and flow of gas-in-oil dispersion is not available. More experimental studies will be performed to obtain PVT data and derive a mathematical model for the Orinoco-belt heavy foamy oil under consideration. Furthermore, numerical simulation studies will be carried out in the near future. Finally, we understand that the foamy-oil behavior not only varies with oil and gas type, viscosity, and temperature, but also is related to depletion rates. However, it is a difficult matter to determine the effect of varying depletion rates on oil recovery in the present project. We will concentrate on this issue in our future laboratory study.

Nomenclature

k = permeability
P_0 = atmospheric pressure
P_1 = pressure in container
p_b = bubblepoint pressure
S_o = oil saturation
S_{wim} = initial water saturation
V_0 = gas volume
V_1 = container volume
Z = gas factor
η = oil recovery
ϕ = porosity

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TABLE 3—PARAMETERS OF THE DEPLETION EXPERIMENTAL MODEL

Experimental Model	Core Length (cm)	ϕ (%)	k (darcies)	S_o (%)	S_{wim} (%)	p_b (MPa)	GOR (m^3/m^3)	Fluid
1	80 x 8	40.5	5	87.8	12.2	9.0	19	Tank oil + gas
2	80 x 8	38.3	7.58	86.9	13.1	9.7	24.5	Tank oil + gas + 10% kerosene

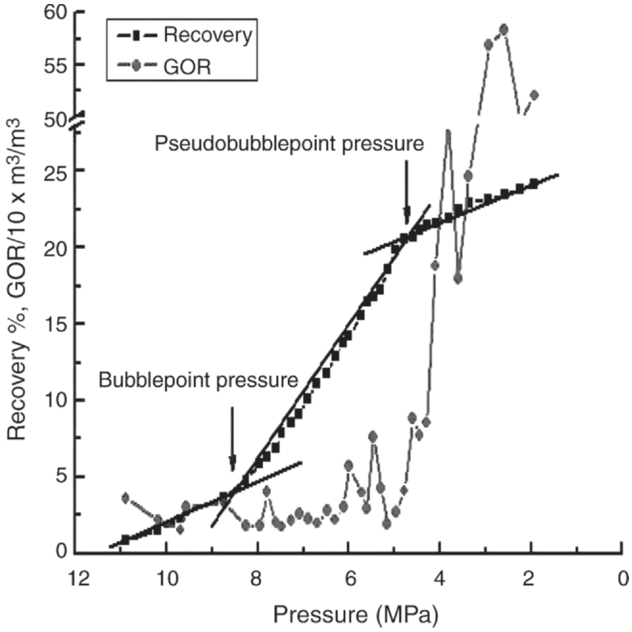

Fig. 6—Production profiles of the depletion experiment.

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Ruihe Wang is a guest professor at China University of Petroleum Beijing and the deputy chief engineer at China National Oil and Gas Exploration and Development Corporation, a branch of China National Petroleum Corporation, in charge of overseas oil-development business. email: wangrh@cnpcint.com. His research interests are in integrated studies in enhanced oil recovery (EOR), oil-production technology, mechanics of multiphase flows in porous media, reservoir-simulation modeling, and simulator development. He holds a PhD degree in reservoir engineering from South-West Petroleum University, Beijing. **Jishun Qin** is professor and director of the EOR Department at the Research Institute of Petroleum Exploration & Development (RIPED). His specialty is in EOR in laboratory and fluid flows in porous media. He holds a PhD degree from China Mining University, Beijing. **Zhangxin Chen** is a professor and Natural Sciences and Engineering Research Council/Alberta Energy Research Institute/Foundation CMG chairman in the Department of Chemical and Petroleum Engineering, University of Calgary, Canada. email: zhachen@ucalgary.ca. His research specialties are in reservoir modeling and simulation and scientific computing. He holds a PhD degree from Purdue University. **Ming Zhao** is the deputy chief engineer in the Science & Technology Management Department of RIPED. His interest is in oil recovery and development. He holds a PhD degree from the China University of Geosciences, Beijing.