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Full Length Article

Influence of fluid and operating parameters on the recovery factors and gas oil ratio in high viscous reservoirs under foamy solution gas drive

Bashir Suleman Abusahmin [a], Rama Rao Karri [a,*], Brij B. Maini [b]

[a] Department of Petroleum & Chemical Engineering, Universiti Teknologi Brunei, Brunei Darussalam
[b] Department of Chemical and Petroleum Engineering, Schulich School of Engineering, University of Calgary, Calgary, Alberta T2N1N4, Canada

HIGHLIGHTS

- Series of 16 pressure depletion tests carried to evaluate the features of foamy oil.
- Foamy oil behavior for four heavy oil-solvent systems were studied systematically.
- 4 systems: heavy mineral oil with methane, ethane, CO_2 and crude oil with methane.
- Study investigates the effects of number of parameters on oil recovery trends.
- Each high viscous oil system was characterized by evaluating different parameters.

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ABSTRACT

Foamy oil flow behavior is reported in several high viscous reservoirs in the world, wherein reduction of pressure was noticed to be the main factor of such characteristics. It is also believed to be a significant recovery mechanism in numerous high viscous heavy oil reservoirs that have revealed higher recovery factors when compared with the fluid flow using ordinary Darcy equation. This research investigates the effects of number of factors that influence the oil recovery trends, as well as the production rates in high viscous reservoirs under foamy solution gas drive behavior. The factors investigated comprised of refined mineral oil versus crude oil, saturation pressure, oil viscosity, drawdown pressure, flow direction, solution gas, pressure depletion rate and gas oil ratio (GOR). Live oil-gas system is prepared by blending a mixture of dead oil with gases such as CO_2, ethane and methane. Each high viscous live oil system was completely characterized by evaluating fluid parameters and operating parameters. The significant outcome of the depletion tests confirms that the decreasing pressure depletion rate result in lower performance. At the similar rate of pressure depletion, higher oil recovery was obtained with methane saturated oil compared to either ethane/CO_2 systems, even though it had the lowest solution GOR. At saturation pressure of 500 psi, the solution GOR was 9.1 m^3/m^3, 28 m^3/m^3 and 33 m^3/m^3 with methane, CO_2 and ethane gas respectively, whereas solution GOR of methane saturated with crude oil were found to be 11 m^3/m^3. Both mineral and crude oil systems displayed similar decline in the oil recovery performance with decreasing pressure depletion rate. In high depletion rate tests, the recovery factor was 26.1%, 23.7% and 19.6% with respect to methane, ethane and CO_2 respectively, whereas in slow depletion runs, the recovery factor declined from 13.1% with methane to 5.5% with CO_2.

1. Introduction

High viscous reservoirs are a significant source of global energy supply and extraction of oil from these reservoirs have gained more prominence to meet the demand of petroleum and its associated products. Foamy oil terminology is commonly used to pronounce a dispersed gas–liquid two-phase fluid, which present in high viscous oil reservoirs, ranges from 10,000 to 100,000 centipoise, mostly in countries like Canada, Oman, Russia, China and Venezuela performed under solution gas drive [1–7]. Recovery factor and gas oil ratio were perceived as prominent features in the high viscous oil reservoirs under foamy solution gas drive when compared with conventional solution gas drive production behavior [1,8–12]. Numerous theoretical and experimental studies [5,10,13–21] have been investigated to understand the

* Corresponding author.
E-mail addresses: karri.rao@utb.edu.bn, kramarao.iitd@gmail.com (R.R. Karri).

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mechanisms of the unusual oil recovery factor in high viscous oil reservoirs under solution gas drive like Lloydminster, Canada. The better oil recovery factor can be partly attributed to foamy oil flow.

During the depletion process, wherein the pressure of the sand pack falls below the bubble point pressure of high viscous oil, a section of small bubbles are developed and eventually trapped in high viscous heavy oil. Because of the potential energy in high viscous reservoir, the amount of gas bubbles starts to migrate within the viscous oil, and displaces the oil to move in the flow direction. While pressure drops in the process, the gas bubbles grow further (primarily by expansion and diffusion), coalesce and under certain conditions, travel towards the top of the system due to buoyancy forces [22]. As the pressure further decays much lower, the bigger bubbles will merge together and form a continuous gas-phase and then the foamy oil flow culminate [23,24]. Simultaneous flow of gas and oil in porous media is a frequently encountered in oil production from oil-bearing rock formations. The oil in an underground formation is generally found at high pressure with substantial amount of natural gas dissolved in it. To illustrate the behavior of natural gas in foamy oil, gas dissolution tests were conducted at different pressures, and a methodology was established for deriving the gas diffusion coefficient [7,25,26]. Reservoir pressure decreases when oil is extracted from it. This decline in pressure reduces the gas solubility and at a certain characteristic lower pressure (bubble point pressure), the gas starts oozing out of solution. As the pressure declines further, the gas starts to flow with the oil towards the production well.

The simultaneous flow of oil and gas through porous media is traditionally defined by expanding Darcy's law to dual phase flow, by introducing the concept of relative permeability [27]. This description of dual phase flow is established based on the observation that the two phases generally flow separately, but in continuous flow channels and the flow mechanism of each phase is driven by the pressure gradient in that particular phase only. Thus in dual phase flow of gas and oil, the gas flows mostly through a pore system and the oil flows through a parallel but separate system. The distribution of the two phases is controlled by interfacial tensions that work to abate the free energy of the interface. This abatement of the free energy implies that the wetting phase would occupy the smallest available pores, which have larger surface area per unit volume of pore space, and the non-wetting phase would migrate to larger pores. An essential requirement for this description of the two-phase flow to work is that the distribution of the two phases is dependent only on the relative saturation of these two phases that are present and essentially independent of the flow velocity. This makes the relative permeability of each phase a function of only its own saturation [28–30].

The preceding description of the two-phase flow works if the fluid distribution is controlled by the interfacial tension and the contribution of viscous forces towards fluid distribution remains insignificant. It works better for modeling the oil production in conventional oil reservoirs by solution gas drive. However, it does not constantly work for modeling solution gas drive related to high viscous reservoirs. Most of the high viscous reservoirs exhibit unusual production behavior, both in terms of unusually high initial recovery factors and higher than expected well productivity, which cannot be modeled by traditional description of two-phase flow [31]. It is because, the conventional relative permeability based description of two phase flow is not applicable to foamy oil flow in which the gas flows in the form of dispersed bubbles in oil. The conventional model predicts that gas oil ratio in the produced fluid stream will increase rapidly with continued depletion but, in reality, in many heavy oil reservoirs this does not occur. The producing gas oil ratio remains much lower than expected and oil production continues down to low average reservoir pressure. It is as if there is something present to severely reduce the flow of gas and thereby divert the drive energy towards continued oil production. It was concluded that, this uncharacteristic production behavior is closely related with the observed foamy oil nature of the produced oil. This type of inconsistent production was first described by Smith [32], who noted that the cold production of heavy oils from several Canadian reservoirs did not fit the conventional solution gas drive models. He described two interesting features of such production: (1) the oil was produced in the form of thick foam that was remarkably stable and (2) substantial volume of sand was produced with the heavy oil. Both of these appear to play a role in the anomalous production behavior. Sand production leads to dilation of sand near the production well and to formation of wormholes that extend the reach of the production well and increase the inflow rate [33]. The foaminess of oil alters the distribution of gas and oil in the pore space and delays the formation of continuous gas phase during oil production [22].

The difference between the solution gas drives in conventional oil and high viscous reservoirs is the relative magnitude of viscous forces. Because of the low mobility of heavy oils, it is necessary to apply very high drawdown pressure in production wells. This large difference in the average reservoir pressure and the well pressure increases the gradient (pressure) and makes the viscous forces comparable to capillary forces. The local capillary number can become high enough to activate an isolated gas bubble which leads to a dispersed gas flow. The gas exsolution study specifies that the pore rebound response pressure depends on liquid and gas properties and sand matrix deformation properties [34–36]. The process has some similarities to in situ generation of emulsions during simultaneous flow of oil and water at high rates and in situ formation of aqueous foams in the presence of surfactants. However, there are also major differences in their characteristics. In foamy oil, the size of dispersed bubbles is much larger than emulsion droplets and the volume fraction of dispersed phase is much smaller than aqueous foams.

The mobilization of dispersed gas bubbles dramatically changes the nature of two phase flow. Because the gas is no longer continuous, its flow is no longer confined to a separate pore network. Moreover, the flow of gas, at least on the macroscopic scale, is now driven primarily by pressure gradient in the oil. The gas bubbles have to displace the oil in order to progress in the direction of flow and their movement is now greatly affected by the oil viscosity. The larger the oil viscosity, lower would be the mobility of gas bubbles [37]. This reduced gas mobility greatly improves the oil recovery performance by preventing, or at least greatly reducing, the rapid dissipation of reservoir energy with production of large volume of gas. Hence, the gas oil ratio now remains relatively small.

Most of the previous laboratory experimental tests are mainly focused on heavy oil methane system [4,10,15,38–43]. From these studies it was established that the oil recovery factor rises with the increase in pressure depletion rate. This conclusion can be attributed due the fact that propane has higher solubility in high viscous oil. In one of the recent study [6] where pressure depletion tests on foamy oil flow were conducted in a one-meter-long sand pack system to investigate the effect of pressure depletion rates on different heavy oil–solvent systems in porous media. Pure methane, pure propane, and a mixture of methane and propane were used as solvents in these tests. In their study, they have concluded that as the pressure decline rate of the high viscous oil methane and propane systems increases, the foamy oil pressure decreases. To the best knowledge of all the authors, there has no published work reported in open literature on the foaminess behavior of saturated mineral oil with gases like methane, ethane, carbon dioxide and saturated crude oil – methane system on recovery factors and production rates.

To investigate the effect of the above aspects and influence of parameters such as gas-oil-ratio, saturation pressure, and the type