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SOLVENT BASED ENHANCED OIL RECOVERY FOR IN-SITU UPGRADING OF HEAVY OIL

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Advances in Heavy Oil Recovery

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ABSTRACT

With the depletion of conventional crude oil reserves in the world, heavy oil and bitumen resources appear to have great potential to meet the future demand for petroleum products. However, oil recovery from those sources is fraught with difficulties as compared to conventional oil reservoirs primarily due to high viscosity even under thermodynamic reservoir conditions, which creates special production challenges. Conventional enhanced oil recovery methods also possess important limitations, ranging from operational difficulties to predictive capabilities. With the advent of innovative drilling technologies, in-situ injection of fluids, simulation and monitoring techniques, heavy-oil reservoirs have been rendered profitable assets. This paper analyzes various recovery techniques for heavy oil production and identifies limitations of present models to evaluate the efficacy of solvents (gases) injection in heavy oil reservoirs as an enhanced oil recovery method. The so far known viscous fingering phenomenon is reviewed considering bubble nucleation events at high oil viscosity as being more probable than bubble

growth and coalescence. Possible effects on relative permeability under different operation conditions are discussed.

Keywords: heavy oil, viscosity, modeling, diffusion-coefficient, solvent injection

1. INTRODUCTION

Heavy oil resources appear to have great potential to meet the future demand for petroleum products. However, oil recovery from those sources is fraught with difficulties as compared to conventional oil reservoirs primarily due to high viscosity even under thermodynamic reservoir conditions, which create special production challenges. Many researchers (Butler and Mokrys, 1989), (Das and Butler, 1996a, 1998b), (Butler and Jiang, 2000), (Boustani and Maini, 2001), (Nghiem et al, 2001), (Cuthiell et al, 2003), (Jha, 1986) have investigated the injection of semi-miscible solvents for enhanced recovery of heavy crude oils from laboratory scale to pilot plant and commercial scale [Turta and Singhal, 2004]. Others have attempted to develop predictive models (Kapadia et al, 2006), (Vafaie-Sefti and Mousavi-Dehghani, 2006), Cuthiell et al, 2003) to simulate the dynamics of solvents–heavy oil interactions in order to improve productivity. This paper analyzes various recovery techniques for heavy oil production and identifies limitations of present models to evaluate the efficacy of solvents (gases) injection in heavy oil reservoirs as an enhanced oil recovery method.

The injection of hydrocarbon or non-hydrocarbon solvents to recover heavy oil involves to a greater or lesser extent: (a) a reduction of its viscosity through molecular diffusion (Das and Butler, 1996a), (Boustani and Maini, 2001), (Nghiem et al, 2001), (Cuthiell et al, 2003), (Jha, 1986), (b) swelling of the oil phase (Yang, and Gu, 2006), (c) reduction of the interfacial tension, and (d) miscibility and mixing of gas and oil. Therefore, the parameters of interest are the

diffusion coefficient of the solvent in heavy oil under the practical reservoir conditions and reservoir simulation and field design (Yang and Gu, 2006) and Oil swelling factor of a heavy oil-solvent system, where crude oil swells due to solvent dissolution. Oil swelling, which is defined as the ratio of the volume of the solvent-saturated heavy oil to the volume of the original heavy oil without any solvent dissolution, is believed to mobilize residual oil (Campbell, B.T. (1983) as well as increase oil saturation and consequently the relative permeability of the oil (Yang and Gu, 2006).

The phenomenon of dispersion (mixing of the solvent with crude oil) is considered crucial to the economic viability of the Vapex process. The porosity of the reservoir media augments this phenomenon possibly due to an increase in molecular diffusivity with solvent concentration leading to decreased oil viscosity, an increase in gas/oil interfacial area and interfacial instabilities (Kapadia et al 2006).

The injection of Carbon dioxide (CO₂) in oil reservoirs is a very common recovery method. The similarity in densities of CO₂ and oil minimizes unfavorable gravity segregation, commonly observed when hydrocarbon gases are used as solvents, while the most important beneficial effects of hydrocarbon gases injection remain.

Depending on thermodynamic reservoir pressure and temperature, CO₂ could be miscible or immiscible with crude. At a constant reservoir temperature, the pressure will define the degree of miscibility reached and the minimum pressure at which miscibility is achieved is defined as the minimum miscibility pressure (MMP). CO₂ and crude are not initially miscible at first contact. However, upon repeated contact through a kind of evaporation-condensation process (Jarrel et al., 2002), miscibility is achieved.

The sweep efficiency is strongly subordinated to the miscibility condition at which the whole flood and recovery process take place. As previously mentioned, principal mechanisms that contribute to the improved recovery when CO₂ is dissolved in oil are summarized as (Qamar and Islam, 2000; Jha, 1986): oil viscosity reduction, oil swelling, interfacial tension reduction, water-oil emulsification (formation of emulsions that control the water mobility) and well stimulation effects (CO₂ huff-n-puff, CO₂ slugs and water flooding, WAG, *Blowdown*).

It has been reported that miscible CO₂ displacement results in around 22% of incremental recovery, while immiscible displacement recovery is approximately 10%. Consequently, operators have traditionally preferred deeper reservoirs, where pressures are above MMP (Qamar and Islam, 2000). However, *Blowdown* following an immiscible CO₂ flood is considered a very effective method in recovering up to 30% of initial oil in place (Jha, 1986).

At miscibility conditions, the viscosity of CO₂ is 1 to 2 orders of magnitude smaller than that of a light oil (viscosity of around 2 cP), and is about 5 to 8 orders of magnitude less than that of a heavy oil (1000 cP). CO₂ injection below the MMP, results in an adverse CO₂/oil mobility relation, which is deleterious to heavy oil recovery, and implies poor sweep efficiency due to the viscous fingering phenomena (Sahimi, 1993).

The CO₂ flooding above MMP results in the formation of a single phase that is less viscosity than the previous oil phase (a previously mentioned enhanced oil recovery mechanism), which improves oil mobility and thus its recovery. However, CO₂ injected at pressures below the MMP (external gas drive) behaves differently as compared to CO₂ injected at pressures above MMP. Nevertheless, throughout the fluids recovery process, the pressure in the reservoir becomes lower

than the MMP. In this last scenery, internal or solution gas drive is known to occur as well as viscous fingering and CO₂ breakthrough is dependent on the flow regime, (Moulu, 1989).

Figure 1 illustrates a plot of pressure dependence with distance from the well for a hypothetical heavy oil reservoir. The balance of forces, viscous and capillary, that control the flow dynamic is identified with respect to the well location through the capillary number (Ca), which is calculated as:

$$Ca = \frac{\partial P / \partial r}{P_c}, \quad (1)$$

where, $\partial P / \partial r$ is the pressure gradient considering radial symmetry:

$$\partial P / \partial r = r_w u_w \mu \phi / k \cdot r \quad (2)$$

and P_c is the capillary pressure given by:

$$P_c = \frac{2\sigma}{r_p} \cos \theta. \quad (3)$$

Ca values, represented in Figure 1, were obtained considering an average pore diameter $r_p = 100 \mu\text{m}$, an interfacial tension $\sigma = 40 \text{ mN/m}$, $\theta = 0$ (completely oil wet) and the data is offered in Table 1.

Notice in Figure 1 how predominance of capillary forces increases with distance from the well, while the dominance of viscous forces increases with the inverse of that distance. The balance of these forces determines the gas phase distribution during its release and transport. From cold production studies of heavy oil reservoirs (Tang and Firoozabadi, 2003) it is known that fingering could not occur and bubbles flow can be developed depending on flow regime. Nucleation, growth, coalescence and break up of bubbles are competing phenomena, which determine the gas dynamics. During the experiment of Tang and Firoozabadi (2003), the capillary number was determined to be approximately 2×10^{-3} , and the flow of bubbles was observed during almost the entire experiment, indicating the prevalence of viscous flow. Similarly, the physical mechanisms that govern this dynamic system will control the CO₂-oil flow if, after CO₂ miscible injection, the pressure drops below the MMP. Under *Blowdown* events, the viscous force is dominant and consequently the flow of bubbles is even more probable.

One of the greatest challenges at field scale simulations of cold production is to quantify the spatial and temporal changes of gas release and its transport processes. This is very relevant for oil recovery. Bubbles flow Dynamics are not adequately described by the conventional Darcian approach for two-phase flow (Bravo, 2007), because the extended Darcy equation disregards the contribution of momentum interchanges among phases explicitly captured in generalized equations via viscous coupling terms (Kalaydjian, 1990):

$$v_o = \frac{k \cdot k_{r_o}}{\mu_o} (-\nabla p_o) + \frac{k \cdot k_{g_o}}{\mu_g} (-\nabla p_g), \quad (4)$$

$$v_g = \frac{k \cdot kr_g}{\mu_g} (-\nabla p_g) + \frac{k \cdot k_{og}}{\mu_o} (-\nabla p_o). \quad (5)$$

Considering that there is no saturation gradient, the capillary pressure gradient should be zero and therefore $\nabla P_o = \nabla P_g$. Thus, previous Eqs. (4) and (5) can be written as:

$$v_o = \frac{k \cdot kr_o^{ap}}{\mu_o} (-\nabla p_o), \quad (6)$$

$$v_g = \frac{k \cdot kr_g^{ap}}{\mu_g} (-\nabla p_o), \quad (7)$$

with apparent relative permeabilities given by:

$$kr_g^{ap} = kr_g + \frac{\mu_g}{\mu_o} k_{og} = kr_g \left(1 + \frac{\mu_g}{\mu_o} \frac{k_{og}}{kr_g} \right), \quad (8)$$

$$kr_o^{ap} = kr_o + \frac{\mu_o}{\mu_g} k_{go} = kr_o \left(1 + \frac{\mu_o}{\mu_g} \frac{k_{go}}{kr_o} \right). \quad (9)$$

Even though it is very important to disconnect viscous coupling of relative permeability in order to understand the physics that govern the curves behavior, equations (6) to (9) indicate that in principle the apparent relative permeability can be considered a viable alternative to illustrate all of the effects. However, it is important to keep in mind that this concept is physically different from the relative permeability. In fact, apparent relative permeability can be greater than one, depending on the relevance of viscous coupling with respect to the purely Darcy terms (relative permeability terms) and spatial and temporal distribution of the phases.

The bubbles flow observed under predominantly viscous flow regime is very favorable to oil flow, because of the viscous coupling contribution. Also, the apparent relative permeability has previously been determined to be greater than one, while capillary numbers guarantee the viscous flow regime. Therefore, operating conditions should be carefully selected to maximize the coupling flow during CO₂ injection for efficient oil production. Figure 2 illustrates the effect of recovery stages on residual oil saturation (*S_{or}*). Notice that only when the injection rate was 0.6 m/d, that the Blowdown produced a significant reduction of *S_{or}*. A lower rate of injection enables more CO₂-oil contact time and depending on production rate, the coupling effect could play an important role. No physical explanation has been espoused for this behavior and other similar observations and it is our opinion that the solution gas driven mechanism of flow should be better elucidated by modeling of the dynamics taking into consideration the effect of viscous coupling.

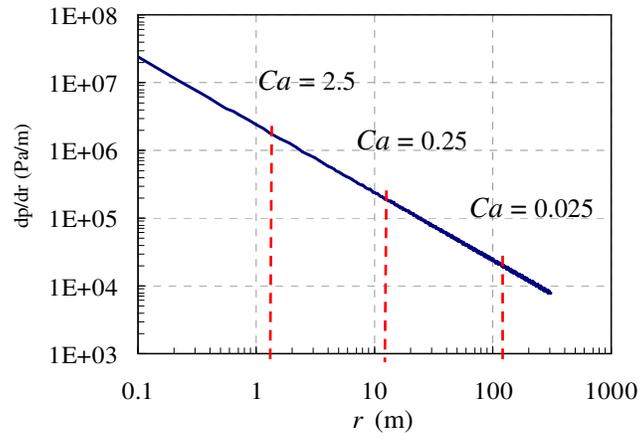


Figure 1: Pressure gradient vs. Distance to the well, considering radial symmetry and data of Table 1.

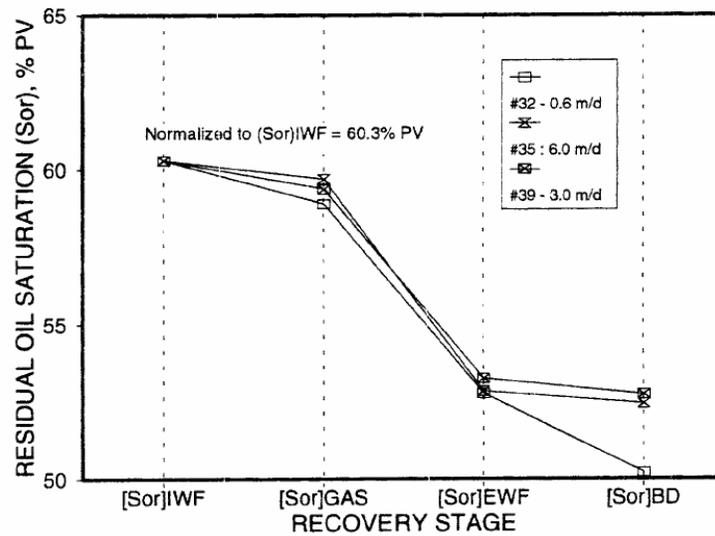


Figure 2: Effect of CO₂ injection rate on waterflood residual oil saturation. IWF: Initial Waterflood, GAS: Gas injection, EWF: Extended Waterflood, BD: Blowdown. Taken from: Srivastava and Huang (1994).

Table 1: Parameters of a hypothetical heavy oil reservoir (based on current data)

Permeability, k (m^2)	5×10^{-12}
Porosity, ϕ (fraction)	0.25
Crude viscosity, μ_o (Pa.s)	3
Well radius, r_w (m)	0.1

Thickness of producer layer, h (m)	20
Production rate, q_w (m ³ /s)	5×10^{-4}

1.1 DIFFUSION COEFFICIENTS AND OIL SWELLING FACTORS FOR CARBON DIOXIDE, METHANE, ETHANE AND PROPANE

Dynamic Pendant Drop Volume Analysis (DPDVA) method (Chaodong Yang and Yongan Gu) is used to measure the diffusion coefficients and oil swelling factors. The oil swelling factor of a heavy oil–solvent system, solubility and viscosity of a heavy oil solvent system are interrelated but the former increases with pressure. The DPDVA method is also applicable for measuring the apparent diffusion coefficient and the apparent oil swelling factor of heavy oil - solvent mixture system.

It is speculated that the diffusion coefficient of a solvent in heavy oil increases with pressure, which can be verified by the determination of the solvent diffusion coefficients at different pressures. Comparison of four solvent injection systems (carbon dioxide, methane, ethane and propane) revealed that the volume increases of the dynamic pendant heavy oil drop surrounded by propane is the largest. This means that the specific surface area of the pendant oil drop is larger at a higher pressure and that the oil drop can be more easily saturated with the solvent. Research indicates that propane has the strongest oil swelling effect due to its high solubility in heavy oil among the four solvents studied.

1.2 EFFECT OF PRESSURE ON THE SOLVENT DIFFUSION COEFFICIENT AND ON OIL SWELLING FACTOR

Studies show that the diffusivities of ethane and propane increase with the dimensionless pressure, which is P/P_v . The solvent diffusivity coefficient and solubility of a solvent increases with pressure which further leads to decrease in oil viscosity. It has been found that the diffusivity of ethane and propane increases with the dimensionless pressure as compared to carbon dioxide and methane.

The oil swelling factors of ethane and propane are large and close to each other, whereas, the oil swelling factors of carbon dioxide and methane are much smaller. Among the four pure solvents (carbon dioxide, methane, ethane and propane), propane has the largest oil swelling factor, which indicates that a significant amount of this solvent dissolves into the heavy oil at a pressure close to its dew point.

2. INJECTION OF COPOLYMER IN ENHANCED OIL RECOVERY

(Sabhapondit et al, 2001) prepared a high molecular weight ($>10^6$) copolymer of *N,N*-dimethyl acrylamide with Na-2-acrylamido-2-methylpropanesulfonate and studied the efficiency of the copolymer as an enhanced oil recovery (EOR) chemical. The recovery efficiency is a function of three factors: (i) Areal sweep efficiency, (ii) Contact factor, and (iii) Displacement efficiency. The sweep efficiency is related to the mobility ratio of the injected fluid (water) to the displaced fluid (oil), which is defined as:

$$\text{mobility.ratio}(M) = \frac{\text{mobility.of.injected.fluid}}{\text{mobility.of.displaced.fluid}} = \frac{K_w/\mu_w}{K_o/\mu_o}$$

where, K_w and K_o are the permeabilities of water and oil, respectively, while μ_w and μ_o are the viscosities of water and oil, respectively. The equation indicates that oil recovery can be increased by increasing the viscosity or decreasing the permeability of aqueous phase in the reservoir.

2.1. DETERMINATION OF PERMEABILITY

The absolute permeability of the unconsolidated sand is determined using Darcy's law,

$$k = \frac{\mu L Q}{\Delta P A}$$

where, μ is the viscosity of the fluid, A is the area of cross section of the column, Q is the flow rate of the fluid, ΔP is differential pressure, and L is the length of the column. If μ is expressed in cp, A in cm^2 , Q in mL/s, ΔP in atm, and L in cm, k will be in Darcy. The parameter k was determined from the slope of the plot of Q vs ΔP using freshwater as the fluid phase. In the case of two phase flow, the effective permeability of the sand to polymer solution was determined using the same equation. It is given as

$$k_1 = \frac{\mu_1 L Q_1}{\Delta P_1 A}$$

where, k_1 is effective permeability, μ_1 is viscosity of the polymer solution when attains steady state, Q_1 is the steady-state flow rate, and ΔP_1 is the differential pressure at steady state.

The permeability reduction due to polymer flooding is determined as follows:

$$\text{Permeability Reduction} = \frac{(\text{Effective permeability before flooding} - \text{Effective permeability after flooding})}{\text{Effective permeability before flooding}} \times 100$$

3. DETERMINATION OF GAS DISPERSION

A mathematical model (Kapadia et al 2006) determined gas dispersion and solubility in a laboratory scale physical model of the VAPEX process using live oil. In this investigation, a block is initially exposed from its sides to a solvent gas at a given pressure and temperature, which diffuses and is absorbed into the medium. This results in the reduction of the viscosity of heavy oil and bitumen causing it to drain under gravity.

4. MEASUREMENT OF GAS DIFFUSIVITY

The molecular diffusion of gases plays a very important role. The gas diffusion coefficient has a direct impact on the amount of gas that is released and the level of super saturation that exists during the pressure depletion. In this investigation, a simple experimental technique for measuring the gas diffusivity coefficient in heavy oils was developed. The diffusion coefficient of carbon dioxide and methane were measured from the rate of gas absorbed at high pressure and employing the diffusion equation with the gas material balance equation (derived from previous data).

4.1 TEMPERATURE FLUCTUATIONS

Fluctuations in temperature further leads to small affect on the pressure. As the pressure decreases, the equilibrium concentration of gases at the interface also decreases, and leads to an increase in their solubility. However, the effect of decreasing temperature counteracts the effect of decreasing pressure on the equilibrium concentration of gas at the interface. Therefore, it can be concluded that the overall effect of temperature fluctuations on the test is relatively small. The

change in gas pressure during the test for the CO₂ oil system was more significant as compared to that of the methane oil system. Therefore, the determination of the diffusion coefficient for CO₂ oil system is expected to be more reliable due to the longer time period.

5. FRICTION (f) THEORY

The friction theory for oil viscosity modeling (Quiñones-Cisneros et al 2001) can deliver highly accurate viscosity modeling above the saturation pressure and also predicts the liquid phase viscosity at pressures below the saturation pressure. A tuned f-theory model delivers accurate modeling of different types of light and heavy oil. Thus, the f-theory is a powerful tool for applications such as reservoir simulations and has been used to characterize oils. The f-theory provides good predictive viscosity performance for reservoir fluids.

6. CONCLUSION

The major challenge in heavy oil recovery is its high viscosity. As a result, most researchers have focused their investigations on this parameter in the laboratory as well as in the field with disparities in the results obtained. This may be attributed to the fact that oil is a complex polydisperse blend of light and heavy paraffins, aromatics, resins and asphaltenes which have diverse behaviors at reservoir temperature and pressures and that there is a dearth of experimental data on gas diffusion coefficients in heavy oils due to the tedious nature of diffusivity measurements. In addition, molecular diffusion is considered to play a major part in supercritical fluid extraction of heavy oils by miscibility displacement. Furthermore, the effect of pressure on the diffusion coefficient and oil swelling factors, ultimately regulate the viscosity and thus oil recovery. Thus, there is great need for better correlations between experimental and theoretical

studies and the measurement of gas diffusivity in heavy oils can provide valuable additional information on the equilibrium solubility of the gas at the test pressure.

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