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Pore level modeling of imbibition in heavy oil saturated media

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ABSTRACT

Heavy oil reservoirs can be found in many locations around the world, such as Canada, Venezuela, United States and Brazil. When in-situ oil viscosity is prohibitively high to allow recovery by conventional methods, additional techniques are used, such as hot water or steam injection. As water exchanges heat with the surroundings, a temperature gradient is established inside the reservoir, which results in a spatial variation of physical properties, especially viscosity. This leads to different mechanisms for fluid flow and trapping. A typical feature of heavy oil immiscible displacements is early breakthrough due to water fingering, which leads to very poor sweep efficiencies. However, physical experiments and field results have demonstrated that additional mechanisms may play a role in heavy oil immiscible displacements, such as capillary imbibition and oil stripping due to high shear flows.

In this paper, a series of numerical experiments are performed to evaluate secondary imbibition at different viscosity ratios and injection rates using a Finite Volume approach to solve the Navier–Stokes equations at the pore-scale, and the Volume of Fluid method to properly capture interfaces. The simulations are performed in a 2-dimensional, water-wet, digital porous medium with complex geometry including dead end pores.

The operating conditions and the associated complex topology allow evaluation of the typical pore-scale events in a secondary imbibition process, such as oil ganglion mobilization, break-up and coalescence, micro-fingering due to capillary imbibition and oil stripping in high shear flows. Thus the main production mechanisms observed in a heavy oil immiscible displacement are successfully reproduced.

1. Introduction

The study of oil recovery from reservoirs containing heavy oil is of interest in several parts of the world, including Canada, Venezuela, United States and Brazil, to name a few. In some cases, oil can flow at reservoir conditions, in spite of its higher viscosity when at surface. In other situations, however, oil viscosity is too high (in the order of millions of mPas) under original reservoir conditions, which renders it essentially immobile. Therefore, thermal techniques must be used to allow mobilization of oil in situ, such as steam flooding, cyclic steam injection, steam-assisted gravity drainage, among others (Butler, 1997). This is the case in many heavy oil reservoirs in Canada, in which steam and/or solvent is used in order to allow oil mobilization and production.

When steam is injected, heat exchange occurs between steam and the surroundings (cold oil region, overburden and underburden), resulting in steam condensation. Therefore, three potential flowing conditions are possible:

1. Two-phase flow of oil and liquid water, which occurs when steam condenses, and oil is basically displaced by hot water.
2. Two-phase flow of steam and oil, which may occur at the steam zone (or chamber). The residual oil that was not displaced by the hot water front drains down, usually in a film flow regime, until a new residual oil saturation level is reached.
3. Three-phase flow of oil, water and steam, in which simultaneous flow occurs with phase change which can be a result of condensation (steam is converted to water condensate once it exchanges heat with the surroundings), or evaporation (when water condensate and heated oil are produced after a soak period in cyclic injection).

In the oil/water two-phase flow region, oil by-passing is the main cause of residual oil saturation, due to its high viscosity. As a result, condensed water reaches the production end more rapidly than oil, due to its much lower viscosity.

The pore-scale mechanisms involved in heavy oil immiscible displacements are complex, even in the absence of a temperature gradient. Alvarez and Sawatzky (2013) discussed the main

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recovery mechanisms involved in heavy oil waterflooding. Among the mechanisms cited by the authors in their review are:

1. Viscous fingering due to unstable displacement resulting in high velocity water channels.
2. Capillary imbibition from the water channels to adjacent regions.
3. Viscous drag exerted by the high velocity water.
4. Stripping of oil and blockage of water channels, diverting water to regions on un-mobilized oil.

As observed, many mechanisms are present in this process, leading to significant differences from immiscible displacements in conventional oil reservoirs. The high viscosity contrasts involved in heavy oil two-phase flows lead to the intuitive conclusion that viscous forces are dominant and capillary forces are negligible, which is not completely true.

In an attempt to verify the effect of viscous forces on immiscible displacements, Vizika et al. (1994) performed numerical and physical experiments in regular pore-network models. The physical experiments were performed in a range of viscosity ratios ($\frac{\mu_o}{\mu_w}$) from 0.66 to 3.35, and no initial water saturation was present before the start of imbibition. They concluded that at low capillary numbers the occurrence of capillary micro-fingers (fingering that occurs in the length scale of one to a few pores) is intensified even at unfavorable viscosity ratios. They also observed an increase in residual non-wetting phase saturation with viscosity ratio.

More recently, a series of sand pack experiments indicated a different trend from that observed by Vizika et al. (1994). Mai and Kantzas (2008a) conducted sand pack experiments with varying viscosity ratios and permeability to investigate the balance between viscous and capillary forces. The heavy oil samples used were in the order of thousands of mPas. The imbibition was started with an initial water saturation, at injection velocities ranging between 10^{-7} and 10^{-6} m/s. They concluded that after breakthrough the contribution of capillary forces are significant, resulting in higher ultimate recovery for the lower permeability cases. Nevertheless, they also verified that for displacement in low permeability sand packs and at lower velocity, a higher oil recovery was also observed at the point of water breakthrough. This indicated that, although viscous forces are dominant before breakthrough, capillary forces will also play a role in oil recovery at this stage.

In another paper, Mai and Kantzas (2009) describe heavy oil waterflooding performed in a sand pack at similar conditions to the previously reported experiments. An increase in oil recovery at breakthrough for lower injection rates was also observed. The only exception was in the case of very low injection velocity ($\sim 10^{-7}$ m/s), in which the recovery at breakthrough was low, but the amount of oil recovered per pore volume injected was the highest (indicating more efficient flooding).

In the case of thermal processes, as hot fluids are injected, a temperature gradient is established within the reservoir, leading to distinct fluids mobility and flowing conditions in different regions. As the distance from the steam zone (or chamber) increases in the direction of the oil zone, oil viscosity will continuously increase with decreasing temperature away of the interface. This is an important implication of thermal methods, and the details of the dynamics of pore scale flows under these conditions still needs investigation. For example, how will the viscosity ratio between hot water and bitumen influence flow patterns that lead to residual saturation? Or what kind of pore-scale events are present which contribute (or not) to residual saturations?

Although other factors are responsible for alterations in oil mobilization in the reservoir during injection of a hot fluid, viscosity reduction is the most important one. It has been discussed previously in the literature that higher initial water saturation has an impact on water breakthrough times (Alvarez and Sawatzky, 2013). Also an increase in temperature may result in contact angle and wettability alterations that may be positive or negative for oil mobility (Sinnokrot et al., 1971; Rao, 1999). Although these factors influence the process, it is expected that the effect of reduction in oil viscosity would be more significant for heavy oil production than other mechanisms that result from temperature increase. Therefore, it is not the current objective of this study to evaluate these parameters.

To give an idea about how temperature and viscosity changes ahead of a steam zone (or chamber), the case of heat conduction ahead of an advancing front is evaluated. The solution of the one-dimensional heat transfer equation considering a quasi-steady state advancement of the steam chamber interface at a constant velocity v_x is (Butler, 1997):

$$\frac{T - T_r}{T_s - T_r} = \exp\left[-\left(\frac{v_x}{\alpha}\right)(x - v_x t)\right] \tag{1}$$

In this equation, T_r is the reservoir temperature, T_s is steam temperature, x is the distance measured normal to the advancing steam interface and t is time. The thermal diffusivity is defined as: $\alpha = \frac{K}{\rho c_P}$, where ρ is the reservoir density, c_P is the reservoir heat capacity and K is reservoir thermal conductivity.

Orders of magnitude of viscosity variation with temperature in the two-phase flow zone were evaluated by using reservoir properties from an example available in the literature (Irani and Ghannadi, 2013). The viscosity can be obtained by using an empirical correlation (Khan et al., 1984). For a reservoir with an original temperature of 15 °C, thermal diffusivity of 7×10^{-7} m^2/s, where steam at 205 °C is injected, and the interface is moving at 2×10^{-7} m/s, the temperature profile ahead of the steam zone is shown in Fig. 1.

As observed in Figs. 1 and 2, the heat transfer boundary layer has orders of magnitude of several meters. The steepest temperature and viscosity gradients will happen in the region closest to the steam zone. In order to evaluate the balance between viscous and capillary forces at the pore level in the two-phase flow region, a “zoom” of a small element of rock is taken, in the order of micrometers. By evaluating the first 1 mm ahead of the steam front, where a steep temperature gradient is present, it can be observed that variation in temperature and viscosity are negligible at this length scale when compared to the extent of the heat transfer boundary layer. To be more accurate, a piece of rock of 1 mm taken ahead of the steam front will have a temperature decrease from 204.89 °C to 204.84 °C, which results in a viscosity increase from 9.028 to 9.036 mPas (Fig. 2).

The digital porous media used in pore scale simulation in this study have dimensions less than 1 mm, therefore, the temperature and viscosity gradients are considered negligible in such a small scale, and for the secondary imbibition cases evaluated in this paper, the element of rock will be considered as isothermal, and the flow will be evaluated with physical properties of the fluids that correspond to specific temperature snapshots.

In this study, a Computational Fluid Dynamics (CFD) approach is used to simulate two phase flows at the pore level. The advantages of direct simulations, like CFD, are the more realistic representation of the digital porous media, and the ability to model other physics that may be present in pore-scale flows in addition to capillary forces (i.e. viscous and inertial forces). The main objectives of the simulations in this paper are to predict multiphase flow patterns in a secondary imbibition process at adverse viscosity ratios and to evaluate the balance between viscous and capillary forces as operating conditions (velocity and