The media describe the behaviour of viscous oil displacement in porous oil discoveries of viscous oil. It is important to correctly model the flow, especially according to the simulation results. Friction pressure drop in the wellbore did not seem to affect the behaviour of viscous oil displacement quantitatively, however, some differences were observed. The friction pressure drop in the wellbore did not seem to affect the flow, especially according to the simulation results.

Introduction

With more frequent use of horizontal wells and new offshore oil discoveries of viscous oil, it is important to correctly describe the behaviour of viscous oil displacement in porous media.

This work aimed to study such behavior through a methodology that involved an experimental displacement test by injecting water in viscous oil through horizontal wells, and the characterization of a porous media.

The fluids and porous media characterization are presented in a correlated work. Since this work involves very unfavourable mobility ratio, the initial discussion will focus on the conditions for displacement stability taking into consideration the high oil viscosity.

Scale transformation from a model to a prototype was studied and the results for the prototype were calculated by scale transformation and by numerical simulation. The pressure, production and saturation distributions were simulated for the model and compared to the laboratory measurements.

Porous Media. The porous media is an Eolian sandstone from Botucatu formation obtained from an outcrop in Ribeirão Claro, PR, Brazil. It was preliminarily cut in a parallelepiped form (88 cm x 33 cm x 3.2 cm), with 24% porosity and 587 mD absolute permeability. The capillary pressure and the water oil stable relative permeabilities can be seen in Table 1, where the normalised water saturation presented is defined by Eq. (1):

$$ S_w^* = \frac{S_w - S_{wi}}{1 - S_{wi} - S_{or}} \quad \text{.................................(1)} $$

Oil Displacement Test

Experimental and Simulation Model Results. The plate was saturated with water under vacuum. The initial water saturation was obtained by injecting the 212 cP viscous oil laterally in linear displacement geometry; the oil injection rate was 0.15 cm$^3$/min. Figure 1 shows a picture of the encapsulated rock plate used in the experiments and the laboratory apparatus. The operating pressure had to be kept to low values due to the large superficial area of the model, otherwise the plate containing the porous media could be damaged. This phase of the experiment provided the irreducible water saturation ($S_w^*$) for Eq. (1).

Stability Criteria

Different authors have studied stability criteria for the flow of water displacing oil. However, since this is not a settled subject, the findings of two authors will be presented here.
Chuoke\textsuperscript{4,5} defined as necessary and sufficient conditions:

\[ M^0 \geq 1 \]  

\[ \lambda = \frac{c}{3} \left( \frac{\sigma' k}{v(\mu_o - \mu_p)} \right) = \frac{190 \sqrt{7442 \times 0.3}}{0.00001 \times 2.11} \geq 33 \text{cm}. \]  

where \( \lambda \) is critical wave length. Since, in this experiment, this critical wavelength is greater than the porous media size, as calculated above, the flow is stable.

Another instability index, \( I_{sc} \) criterion, was proposed by Peters\textsuperscript{4}:

\[ I_{sc} = \frac{(M - 1)(v - v_c)\mu_w d^2}{N_k w_{or} \sigma} \]  

Substituting the values of this experiment in Eq. (4):

\[ I_{sc} = \frac{(212 - 1)(0.000025 - 0) \times 1 \times 33 \times 3.28}{306.25 \times 0.08 \times 45} \]  

The result of Eq. (5) is \( I_{sc} = 0.00052 \), which also shows that the flow is stable (the condition for stability, according to Peters, is \( I_{sc} < 13.56 \)).

The very low injection rate used in this work has turned a non-favourable mobility ratio into a stable flow. For this reason, typical relative permeabilities curves for stable flow will be used in the simulation runs.

**Scale Transformation**

A field prototype has been created and scale transformation was used to make it similar to the laboratory model. The simulation of this field prototype should yield equal results to the scaling model.

Various authors have studied scale transformations in laboratory experimental models\textsuperscript{6,13-16}. The focus of this work will be directed towards two classical papers. The similarity groups described by Geertsm\textsuperscript{a} et al.\textsuperscript{6} were obtained through dimensional and inspectional analysis for a cold-water test with given injection rate.

The similarity groups\textsuperscript{6} are:

From Darcy Equation:

\[ \frac{l}{h}, \frac{\alpha}{\mu_w}, \frac{\rho_o}{\rho_w}, \frac{k\rho_w g}{\mu_w b}, \frac{\sigma \cos \theta \sqrt{kp}}{v \mu_w l} \]  

From general flow equation:

\[ \frac{v \rho_w \sqrt{k}}{\mu_w}, \frac{1}{\sqrt{k}}, \chi \]  

From initial and boundary conditions:

\[ \frac{S_{ai}}{S_{ai}} \]  

Aside from the similarity groups, the following dependent groups are considered important:

\[ \frac{q_w \Delta p k}{q_p v \mu_w l} \]  

A dimensionless time group is defined as:

\[ \frac{t_v}{l \tau} \]  

The final similarity groups for an injection test with cold-water are shown in Eqs. (11) and (12):

\[ \gamma(v^2) = \gamma\left(\frac{\mu^2}{k}\right) = \gamma\left(\frac{\Delta p g \sqrt{k}}{l}\right) = \gamma\left(\frac{\sigma \cos \theta}{l}\right) \]  

\[ \gamma(\phi) = \gamma(\rho) \]  

Equivalent results were presented in another paper, by Rapoport\textsuperscript{16}:

\[ \left[ \frac{q \mu_w}{l^2 k \Delta \rho} \right]_{\text{model}} = \left[ \frac{q \mu_w}{l^2 k \Delta \rho} \right]_{\text{prototype}} \]  

\[ \left[ \frac{q \mu_w}{l \ k P_c} \right]_{\text{model}} = \left[ \frac{q \mu_w}{l \ k P_c} \right]_{\text{prototype}} \]  

\[ \left[ \frac{k P_c^2}{\phi \sigma^2} \right]_{\text{model}} = \left[ \frac{k P_c^2}{\phi \sigma^2} \right]_{\text{prototype}} \]  

Some precautions are necessary to obtain reasonable characteristics of the transformed field prototype. In this work, the relations defined by Eqs. (16)-(19) were chosen:

\[ \frac{l_p}{l_m} = \frac{y_p}{y_m} = \frac{h_p}{h_m} = 1000 \]  

\[ \frac{q_p}{q_m} = 1000000; \frac{\phi_p}{\phi_m} = 1; \frac{k_p}{k_m} = 10; \frac{\Delta \rho_p}{\Delta \rho_m} = 0.1 \]  

\[ \frac{\mu_p}{\mu_m} = 1; \frac{P_{cp}}{P_{cm}} = 100; \frac{v_p}{v_m} = 1. \]
\[ \frac{\sigma_p}{\sigma_m} = 316; \frac{t_p}{t_m} = 1000 \] ..............................(19)

These relations satisfy the criteria presented by the mentioned authors; in short, the geometrical transformation is 1000 times (from laboratory scale to prototype); the model rate of 0.15 cm³/min corresponds to a rate of 1358.5 bbl/day in the prototype; the time transformation is 1000 times and the pressure variations in the prototype are 100 times the pressure variations in the model.

The boundary condition is set by Eq. (20):

\[ v(t) = \frac{1}{h} \int_0^h v_w dy \] ..............................(20)

Since a horizontal injection well is being considered, it was proposed that the friction losses in the well prototype and the well model were related to the pressure losses in prototype and model, i.e., (prototype well friction losses)/(model friction losses) = 100.

Results and Discussion

The pressure and the production history during oil injection are shown in Fig. 2. The water saturation distribution is presented for time = 1400 minutes in Fig. 3. It can be seen that the oil front moves uniformly through the porous media, from rows 1 to 22 in the “Longitudinal” axis. The oil reaches the production well at approximately \( t = 2000 \) minutes and its production rises steadily from then on. The irreducible water saturation, taken from this experiment, was \( S_{wi} = 0.31 \).

The corresponding simulated profiles for Figures 1 and 2 are shown in Figures 4 and 5. Similar behavior to the experimental one was observed, with the oil front advancing uniformly through the porous media.

Figure 6 shows the pressure-production history during the water injection test. The pressure drop observed in the producer was very small at the beginning of the experiment, around 0.1 psi. After reaching a maximum of 0.21 psi, the pressure drop falls quickly due to the breakthrough of water. From the pressure/production data it was possible to calculate a well radius which was in agreement with previously measured equivalent well radius.

Figure 7 presents the pressure-production history according to the simulation data, which are in agreement with the laboratory results to a certain degree. Pressure losses due to friction were not considered in the injector well during the simulation, as the values observed in the experiment were very low.

The water saturation maps, showing the advance of the water front, are presented in Figures 8 and 9 for different times. According to the saturation maps, a normal, uniform advance of water can be seen till the end, when the heel of the producing well receives water more rapidly.

The corresponding simulated results are displayed in Figures 10 and 11. Figures 8 and 10 (at 540 minutes) show some similarities, e.g., the range of saturation values is not too dissimilar (from 0.31 to 0.55); some of the differences include the extent to which water has penetrated the plate; it can be observed that, in the simulated saturation map (Fig. 10), the water front is still approaching the middle section of the porous media, whereas some water seems to have penetrated up to the end of the plate, where the producer is located (row 1 in Fig. 8). Figures 9 and 11 present somewhat greater differences, especially near the producer; the experiment data indicates a remarked increase in the water saturation near the producer (compared to \( S_w \) values in the middle section) and an unsymmetrical distribution of water; this last phenomenon, particularly, is not observed in the simulated saturation map, where water saturation declines smoothly from the injector to the producer.

Figure 12 was generated after the scale transformation, i.e. it corresponds to Fig. 6 (pressure-production history). It is a direct scale transformation according to the discussion in the scale transformation section; therefore, the behavior observed is the same, though the absolute values are considerably higher. Figure 13 presents the corresponding simulated profiles with the plate and well characteristics defined by the scale transformation. The behavior observed is qualitatively similar to that observed in Fig. 12; the cumulative water production and injection curves reproduce reasonably well the data in Fig. 12, however, the injector pressure and the producer pressure drop in Fig. 13 do not decrease at the same rate they do in Fig. 12. According to the theory studied, the saturation maps should present no modification, therefore Figures 8 and 9 (experimental scale) are identical to Figures 14 and 15 (field prototype).

Water saturation maps from the field scale simulation are shown in Figures 16 and 17; these are the equivalent to Figures 14 and 15; however, some differences can be observed; according to Fig. 14, water would have penetrated considerably further in the plate after 375 days, raising \( S_w \) values near the producer. This does not occur in the simulation results (Fig. 16). At 2292 days, both the scaled experimental and the scaled simulation maps show increased water saturation near the injector and near the producer, as seen in Figures 15 and 17; the simulation model was composed of three layers and the surfaces shown are an average of the three-layer saturation values; the considerable increase in \( S_w \) near the producer (compared to saturation values seen in the middle section of the reservoir) indicates that the water is moving faster through the lowest layer; this phenomenon was not observed in the laboratory scale simulation, but it is quite clear in the reservoir model; again, the simulation calculated lower water saturation values in the reservoir compared to the scaled experimental results.

Concluding Remarks

A rock plate with petrographic, petrophysical and flow properties equivalent to those of a reservoir rock was prepared for lab tests. The rock had its porosity and permeability distribution, relative permeabilities and capillary pressure measured. A tracer test was performed to study oil displacement with water; the tracer showed an appropriate flow performance and allowed the generation of saturation maps during the experiment.

A scaled transformation was performed in order to apply the laboratory results to a prototype field-scale model. The data acquired in the oil displacement experiment were used to
build numerical simulation models for the oil injection and the water injection cases (in laboratory and field scales).

The pressure-production history results obtained from the simulations were qualitatively similar to the experiment results, with greater differences being observed in the pressure profiles. Although the generated saturation maps show practically the same range of Sw values, some discrepancies were observed, mainly in the extent to which water penetrated the porous media. Pressure losses due to friction in the wellbore did not seem to influence the flow, especially in the simulation cases, despite the high oil viscosity. This phenomenon will be investigated further.

Acknowledgements
The authors are grateful to the Conselho Nacional de Desenvolvimento Científico e Tecnológico (CNPq), to FINAP and to PETROBRAS for their financial support to this project. The authors are also grateful to Luiz B. Pompeo Netto and to Leandro A. Fernandes for their great assistance with the experiments.

Nomenclature

\[ c = \text{Chuoke’s constant} \]
\[ d = \text{diameter, [cm]} \]
\[ f = \text{fractional flow} \]
\[ g = \text{gravity acceleration, [cm/s}^2]\]
\[ h = \text{thickness, [cm]} \]
\[ I_{sc} = \text{stability index} \]
\[ k = \text{absolute permeability, [mD]} \]
\[ kr = \text{relative permeability} \]
\[ kw_{or} = \text{water permeability in the presence of residual oil} \]
\[ l = \text{length, [cm]} \]
\[ M = \text{mobility ratio} \]
\[ M^i = \text{initial mobility ratio} \]
\[ N_w = \text{wettability number} \]
\[ p = \text{pressure, [psi]} \]
\[ \Delta p = \text{pressure differential, [psi]} \]
\[ q = \text{injection rate, [cm}^3/s] \]
\[ S = \text{saturation} \]
\[ S_o = \text{oil saturation} \]
\[ S_{re} = \text{oil residual saturation} \]
\[ S_w = \text{water saturation} \]
\[ S_{sw} = \text{normalized water saturation} \]
\[ S_{wil} = \text{irreducible water saturation} \]
\[ t = \text{time, [s]} \]
\[ v = \text{velocity, [cm/s]} \]
\[ v_c = \text{critical velocity, [cm/s]} \]
\[ W_i = \text{cumulative water injected, [cm}^3] \]
\[ y = \text{width, [cm]} \]
\[ \alpha = \text{porous media inclination, [degree]} \]
\[ \chi = \text{internal porous characteristics} \]
\[ \gamma = \text{scale transformation} \]
\[ \phi = \text{porosity} \]
\[ \lambda = \text{critical wave length, [cm]} \]
\[ \mu = \text{viscosity, [cp]} \]
\[ \theta = \text{contact angle, [degree]} \]
\[ \rho = \text{density, [g/cm}^3] \]
\[ \sigma = \text{surface tension, [dyn/cm]} \]
\[ \sigma^* = \text{effective surface tension, [dyn/cm]} \]
\[ \tau = \text{characteristic time} \]

Subscripts
\[ c = \text{critical} \]
\[ m = \text{model} \]
\[ o = \text{oil} \]
\[ p = \text{prototype} \]
\[ w = \text{water} \]

References

SI Metric Conversion Factors

<table>
<thead>
<tr>
<th>Unit</th>
<th>Conversion Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>bbl</td>
<td>x 1.589 873 E-01 = m³</td>
</tr>
<tr>
<td>cP</td>
<td>x 1.0* = Pa.s</td>
</tr>
<tr>
<td>psi</td>
<td>x 6.894 757 E+00 = kPa</td>
</tr>
<tr>
<td>mD</td>
<td>x 9.869 233 E-02 = µm²</td>
</tr>
<tr>
<td>cm³</td>
<td>x 1.0* = m³</td>
</tr>
<tr>
<td>cm²</td>
<td>x 1.0* = m²</td>
</tr>
<tr>
<td>g</td>
<td>x 1.0* = kg</td>
</tr>
<tr>
<td>dyn</td>
<td>x 1.0* = N</td>
</tr>
</tbody>
</table>

* Conversion factor is exact

Figure 1. Encapsulated rock plate and laboratory apparatus (from Bonet et al. 3)

Figure 2. Experimental Pressure values and Production during Oil Injection in Plate

Figure 3. Experimental Water Saturation during Oil Injection in Plate

Figure 4. Simulated Pressure values and Production during Oil Injection in Plate

Figure 5. Simulated Water Saturation during Oil Injection in Plate
Figure 6. Experimental Pressure values and Production during Water Injection in Plate

Figure 7. Simulated Pressure values and Production during Water Injection in Plate

Figure 8. Experimental Water Saturation for Water Injection in Plate at 540 minutes

Figure 9. Experimental Water Saturation for Water Injection in Plate at 3300 minutes

Figure 10. Simulated Water Saturation for Water Injection in Plate at 540 minutes

Figure 11. Simulated Water Saturation for Water Injection in Plate at 3300 minutes
Figure 12. Experimental Pressure-Production History for Scaled Field Data

Figure 13. Simulated Pressure-Production History for Scaled Field Data

Figure 14. Experimental Water Saturation for Water Injection in Scaled at 375 days

Figure 15. Experimental Water Saturation for Water Injection in Scaled at 2292 days

Figure 16. Simulated Water Saturation for Water Injection in Scaled at 375 days

Figure 17. Simulated Water Saturation for Water Injection in Scaled at 2292 days
Table 1 - Relative Permeability and Capillary Pressure

<table>
<thead>
<tr>
<th>Sw</th>
<th>Krw</th>
<th>Kro</th>
<th>Sw</th>
<th>Pc (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.000</td>
<td>0</td>
<td>1</td>
<td>15</td>
<td>35.0</td>
</tr>
<tr>
<td>0.180</td>
<td>0</td>
<td>0.9956</td>
<td>15</td>
<td>15.0</td>
</tr>
<tr>
<td>0.298</td>
<td>0</td>
<td>0.7309</td>
<td>17</td>
<td>8.0</td>
</tr>
<tr>
<td>0.329</td>
<td>0.0</td>
<td>0.6725</td>
<td>22</td>
<td>3.5</td>
</tr>
<tr>
<td>0.361</td>
<td>0.0006</td>
<td>0.6153</td>
<td>36</td>
<td>2.0</td>
</tr>
<tr>
<td>0.375</td>
<td>0.0023</td>
<td>0.5907</td>
<td>62</td>
<td>1.0</td>
</tr>
<tr>
<td>0.402</td>
<td>0.0113</td>
<td>0.5467</td>
<td>82</td>
<td>0.9</td>
</tr>
<tr>
<td>0.413</td>
<td>0.0140</td>
<td>0.5296</td>
<td>90</td>
<td>0.8</td>
</tr>
<tr>
<td>0.471</td>
<td>0.0284</td>
<td>0.4445</td>
<td>95</td>
<td>0.5</td>
</tr>
<tr>
<td>0.497</td>
<td>0.0348</td>
<td>0.4095</td>
<td>100</td>
<td>0.0</td>
</tr>
<tr>
<td>0.525</td>
<td>0.0418</td>
<td>0.3739</td>
<td></td>
<td></td>
</tr>
<tr>
<td>0.586</td>
<td>0.0569</td>
<td>0.3030</td>
<td></td>
<td></td>
</tr>
<tr>
<td>0.657</td>
<td>0.0746</td>
<td>0.2308</td>
<td></td>
<td></td>
</tr>
<tr>
<td>0.759</td>
<td>0.1</td>
<td>0.1439</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.000</td>
<td>0.1595</td>
<td>0</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>