Slim-tube simulation model for carbon dioxide enhanced oil recovery

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Abstract

A simulation model of the slim-tube test has been developed to validate the laboratory experiment and used EOS as well as to investigate the possibility of serving as a fast and reliable tool for MMP determination. Sensitivity analyses were performed by testing different grid block sizes (a different number of cells), changing Corey’s coefficients for relative permeability curves, varying flow rates and PVT models. Minimum miscibility pressure from the simulation model is estimated as the intersection of the two different trend line curves of oil recoveries versus the injected volume of CO2. The oil recoveries were underestimated by numerical simulation on a basic case model. This is related to the usage of single “X shaped” relative permeability curves in all simulation cases, i.e. for immiscible, near miscible and miscible conditions. In addition, by fine tuning binary interaction parameters in the equation of the state model and introducing different relative permeability curves for immiscible and near miscible cases, better matching of slim-tube simulation can be achieved.

Keywords

MMP, slim-tube, EOS, EOR, CO2 injection

1. Introduction

CO2-EOR is an attractive miscible process in which CO2 is injected and mixed with reservoir oil, resulting in the oil swelling and a reduction in oil viscosity, thus affecting the capillary number, $N_c$. Microscopic displacement efficiency ($E_d$) largely depends on CO2 injection conditions. Since it is a function of residual and critical oil saturation $E_d = f(S_{or}, S_{cr})$, properties of gaseous and liquid phases will change with the distance from the injector to the producer wells. When CO2 starts to mix with the oil in different proportions at some distance from the injector, different oil compositions occur in the reservoir. As the composition of oil changes, oil volume increases, resulting in higher relative permeability to oil, reduced oil viscosity and changed $S_{or}$. If the minimum miscibility pressure (MMP) is not reached in the reservoir, the free CO2 phase starts to flow several times faster than the oil phase, increasing the relative permeability to CO2 phase in the flowing pathways. The effect of swelling can be observed in the laboratory by successive addition of CO2 into the oil sample in a PVT cell, increasing the pressure until the new mixture of oil becomes a single phase (saturation pressure), and by recording the volume of the new liquid composition at the observed pressure. The other beneficial effects are the oil viscosity reduction and favorable change of interfacial tensions (IFT) between the fluids in the reservoir. The change in the IFT is directly affecting the shape of relative permeability ($k_r$) curves - they become more linear (both phases become more mobile) when IFT between CO2 and oil decreases until absolute miscibility is reached, characterized by an x-shaped relative permeability curve (see Figure 1).

To reduce laboratory work and time needed for determination of the optimal conditions for CO2 Enhanced Oil Recovery (EOR), a sensitivity analysis of parameters in a slim tube simulation model has been performed. Slim-tube experiments compared with the simulation are rarely found in literature and are usually lacking systematic analysis of the parameters that affect the results of CO2 EOR laboratory studies. The use of slim-tube simulation as a substitute for slim-tube experiments was not considered in literature so far.

The analysis described in this work is based on an extensive PVT laboratory study of an oil sample from the Ivanic oil field in Croatia. It is focused mainly on determining the minimum miscibility pressure (MMP) as threshold pressure above which maximum feasible recovery (i.e. displacement efficiency) is possible, which is prominent in a smaller amount of injected CO2 to
achieve target oil recovery (Alomair et al., 2015; Ayirala and Rao, 2011). The MMP was determined based on experimental slim-tube results and by analyzing the calibrated slim-tube simulation model. The slim-tube experiment is not a part of a routine PVT analysis – it requires special equipment, and is time consuming, which makes determining MMP based only on the equation of state (matched with experimental results) and the slim-tube simulation an attractive option.

2. Monographic literature review

The slim-tube experiments and its simulation as a part of EOR methods have been studied by various authors who are still considering it the best tool to study the miscibility and the interactions between the reservoir oil and the solvent. Different methods of predicting the MMP are presented where it is obvious that no uniform agreement of the MMP determination exist.

2.1. Laboratory and numerical studies of CO$_2$-EOR efficiency

Klinkenberg (1957) showed that the pore size distribution is related to immiscible and miscible displacement in a different way. Hall and Geffen (1957) proposed a mathematical model to predict volumes of bubble point liquid, gas flow in a two-phase zone and then for liquid saturation in different zones. They used pure methane, propane, butane and other simple compositions of fluids in their analysis, and divided the injection length to dry zone, two-phase region and region of complete liquid saturation. Their study is supplemented by the work of Lacey et al. (1958), who studied the length of the mixed zone in cores of different diameters, and found that the length of the mixed zone is proportional to the core diameter, but that these results cannot be extended to the reservoir scale.

After extensive laboratory studies, Blackwell et al. (1959) listed the key factors for miscible displacement: (1) the mixing between solvent and oil results principally from molecular diffusion, (2) channeling and bypassing of oil will occur in all (even homogeneous) reservoirs, (3) the volume of solvent required for complete recovery of the oil increases as the mobility ratio increases at breakthrough, (4) higher permeability heterogeneity can be related with lower oil recovery, and (5) gravity segregation can prevent channeling in reservoirs with adequate permeability and dip. Their critical fingering rates were in good agreement with the theoretical model (about 0.00845 cm/s i.e. 1 ft/hour).

The number of studies of miscibility mechanisms increased in the 1960’s (Benham et al., 1960; Adamson and Flock, 1962; Rutherford, 1962). Benham et al. studied miscibility between rich gases and reservoir fluid. They used a pseudo ternary diagram with 3 components: methane, C$_2$-C$_4$ and C$_5$+, and developed a correlation for the maximum methane concentration in miscible conditions as a function of temperature, pressure, C$_2$ molecular weight and C$_5$+ molecular weight of injected gas. Different components in the ternary or pseudo ternary diagram are used for the analysis in literature (Wilson, 1960; Welge et al., 1961), but they are generally divided into light (and/or non-hydrocarbon) components, medium and high molecular weight components. Deffrenne et al. (1961) warned that this approach is not suitable for describing the change of oil composition in different parts of a reservoir.

Koval (1963) proposed the K-factor method (which showed good predictions in miscible systems with viscous fingering and heterogeneity) using a modification applicable to Buckley-Leverett equations (1942). His results were followed up in a study performed by Dougherty (1963) who also observed mixing rate change with an extremely non-linear trend, and that displacement becomes more stable if flowing length is large enough. In this analysis, Koval’s method showed very satisfactory results only for horizontal systems.

Peaceman and Rachford (1962) defined a numerical method for calculating the two-dimensional displacement of oil by solvent to mathematically describe the mechanics of viscous fingering and pore space heterogeneity. They used a random number generator that produced normally distributed random permeabilities and reached good agreement with the experimental results.

Perrine (1963) and Kyle and Perrine (1963) focused on establishing relationships on both unstable and stable displacements. Unstable displacements are found within viscous fingering and non-linear flow that is not in ac-

Figure 1: General shape of relative permeability curve at miscible, near miscible and immiscible conditions.
cordance with Darcy’s law. They pointed to the need for experimental studies on the dependence of flowing velocity and heterogeneity.

Fitch and Griffith (1964) investigated the alternate injection of water and gas which resulted in greater areal sweep efficiency, and vertical sweep efficiency in stratified systems. Based on their experimentally determined solubility, swelling and viscosity data for CO2 – oil systems.

Simon and Graue (1965) published correlations for predicting these properties as a function of viscosity and oil gravity. Rathmell et al. (1971) used long cores (up to 13 m, diameter about 5 cm, porosity, φ = 0.27, permeability, k=1000 mD) to study CO2 displacement at different pressures. They concluded that immiscible displacement by CO2 can yield efficient recovery by oil vaporization and swelling of the heavy ends and that recovery increases with core length.

Awang and Ali (1980) examined thermal effects of injected solvent. They did not found a good match between the observed and calculated temperature and concentration profiles which is attributed to the complex relationship between heat convection and the dispersion of phases.

Numerical simulation algorithms applicable to CO2 flood predictions were developed by Lantz (1971), Pope and Nelson (1978), Orr (1980) and Graue and Zana (1981).

Teja and Sandler (1980) estimated the densities of CO2-oil mixtures, swelling factors and solubility of CO2 in oil at a given temperature, by using equation of state (EOS) parameters, primarily adequate mixing rules and adjusted binary interaction parameters (BIP). Almost the same results are summarized in Mulliken and Sandler (1980) and an appropriate EOS is proposed. Gardner et al. (1981) studied phase behavior of CO2-oil system and recommended data from multiple-contact before single-contact experiments be used in determining phase-behavior models for CO2 flooding simulations.

Wang (1982) showed by visual observations at specially designed equipment, that miscible, semi-miscible and immiscible displacement exist simultaneously during CO2 flood. He concluded that oil recovery cannot be the only criterion for determining the MMP and proposed guidelines for choosing optimal CO2 slug in the WAG process.

The work of Orr et al. (1983) is one of the few where experimental slim-tube results are compared with simulated slim-tube results for CO2 injection. They observed phase composition and density change during CO2 injection and concluded that the continuous multiple-contact (CMC) test offers significant advantages over the slim-tube test.

However, for the simulation model they used the relative permeability correlation given by Naar et al. (1962) which might be inadequate for near-miscible and miscible conditions, and their conclusion is based on one sample, four pressures and a very low (reservoir) temperature of 32°C.

Glasø (1985) clearly defined MMP as the lowest pressure at which the distinct point of maximum curvature is apparent when recovery of oil is plotted against the pressure at 1.2 PV gas injected. When a distinct point of maximum curvature is not apparent, the 95% recovery of oil at 1.2 PV injected gas is used to define the MMP. His study showed that paraffininity has a strong effect on MMP and corrected the K factor for C7+ to adjust his results with MMP’s from North Sea oil systems.

Considering the MMP predicting correlations, they can be helpful for a quick assessment, but they are more or less accurate considering different oil compositions, i.e. the accuracy strongly depends on carbon-number distributions.

2.2. Relative permeability at immiscible and near miscible conditions

Sigmund et al. (1984) proposed a method for slim tube simulation in conjunction with a simple correlation for relative permeability in the model (see Equation 1 and Equation 2):

\[ k_m = \left( \frac{S_o - 0.15}{1 - 0.15} \right)^2 \]  

\[ k_g = \left( \frac{S_g - 0.04}{1 - 0.19} \right)^2 \]

Where:

- \( S_o, S_g \) - oil and gas saturations
- \( k_m, k_g \) - oil and gas relative permeabilities

The model showed applicability for complex oil models, characterized by Peng-Robinson’s (1976) equation of state (EOS) and more than 10 components. Jankovic (1986) who obtained excellent matches with experimental solvent and oil relative permeabilities published more extensive analysis results. For a homogeneous pore system, with a mobility ratio of M=1 and very small interfacial tension IFT=1, the relative permeability of solvent and oil showed straight lines through the origin.

Civan and Donaldson (1989) developed a semi-analytical method that should allow high displacement flow rates for unsteady-state measurements by the inclusion of capillary pressure to better describe the end effects.

Parvazdavani et al. (2013) measured relative permeability for light oils and CO2, and for dolomite and sandstone rock samples. Since the Civan and Donaldson method underestimates relative permeability for oil, they validated Civan and Donaldson’s method by estimating relative permeabilities as a starting point for further slim-tube history matching. They showed their
Table 1: Reservoir fluid composition and properties

<table>
<thead>
<tr>
<th>Comp</th>
<th>Comp (mol %)</th>
<th>MW</th>
<th>SG</th>
<th>Tc (°C)</th>
<th>Pc (bar)</th>
<th>AF</th>
<th>A</th>
<th>B</th>
<th>Vcrit (m³/kg mol)</th>
<th>Vol. Shift</th>
<th>P-chor</th>
<th>Tb (°C)</th>
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<td>28.01</td>
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<td>33.92</td>
<td>0.039</td>
<td>0.42748</td>
<td>0.08664</td>
<td>0.0898</td>
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<td>-195.75</td>
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<td>0.42748</td>
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<td>0.1800</td>
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<td>0.612</td>
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<td>C₂₆::C₃₂</td>
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<tr>
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Table 2: List of Binary Interaction Parameter used in the EOS

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<th>N₂</th>
<th>CO₂</th>
<th>C₁</th>
<th>C₂</th>
<th>C₃</th>
<th>C₄</th>
<th>C₅</th>
<th>C₆</th>
<th>PS-1</th>
<th>PS-2</th>
<th>PS-3</th>
<th>PS-4</th>
<th>PS-5</th>
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<tr>
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<tr>
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<td>0.00</td>
<td>0.00</td>
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<tr>
<td>C₃</td>
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Figure 2: Hoffman plot for K-values quality check using the DL test EOS results for 81 bar pressure step
analysis at several pressures and found that the effect of near miscibility is more pronounced for the CO₂ relative permeability (Corey’s exponent approaches one) than for the oil relative permeability (which had almost no change with pressure).

Li et al. (2015) used both core samples and the slim-tube to find reliable relative permeability curves for simulation purposes. They correlated the shape factor in Corey’s model with displacement pressure but emphasized that the relative permeability curves should be adjusted with the history-matching method. CO₂–oil relative permeability curves obtained in the composite core were more reliable than those of the short core segment but still not accurate enough to simulate miscible conditions.

2.3. Feasibility of CO₂-EOR

There are alternatives to the slim-tube test to evaluate CO₂-EOR. However, the slim-tube experiment connects a volume of injected CO₂ with oil recovery. Wolsky and Jankowski (1986) developed a techno-economic framework to estimate the feasibility of CO₂ EOR projects. They combined all techno-economic parameters into a single equation and concluded that the key economic parameters for determining the permissible cost of CO₂ supply and target additional recovery are oil price and internal rate of return. Martin and Taber published (1992) a figure that relates the maximum CO₂ cost for CO₂ flooding with oil price and rate of return. Even though the operating costs are significantly different

Figure 3: Comparison of experimental and simulated PVT data
nowadays, the diagram shows a linear correlation between costs, amount of injected CO₂ and produced oil.

3. Experiments and numerical model

All of the laboratory experiments were conducted at INA upstream laboratory at the beginning of the 1990s. That includes the standard PVT analyses with the addition of the swelling test using recombined oil and CO₂, and the slim-tube experiment. Numerical modeling was performed in Schlumberger Eclipse 300 software.

3.1. PVT analysis

Laboratory PVT Experiments – wellstream analysis, constant composition expansion (CCE), differential liberation (DL), separator test and viscosity measurements were conducted in order to obtain the volumetric behavior and the original reservoir fluid composition. Separator oil and gas were physically recombined according to the average field gas to oil ratio (GOR) value of 67.5 m³/m³. Oil swelling test with CO₂ as a solvent fluid was also performed, starting from the initial bubble point pressure of 137.2 bar up to 220 bar where saturation pressures were recorded. In that range, no critical phase transition was observed (see Figure 3).

3.2. EOS modeling

Fluid modeling was done within the IPM PVTp software using the Soave-Redlich-Kwong (1972) EOS. The tuning was done by splitting the C₇+ fractions into 5 pseudo fractions (PS), giving a total of 13 components. Binary interaction parameters (BIP) between the C₇ and PS were used to develop the phase envelope curve. The BIPs regarding the hydrocarbon interaction between nitrogen and CO₂ were selected according to the recommendations from Whitson and Brule (2000). Volumetric data was matched by modifying the pseudo fractions’ critical properties and volume shift data. The viscosity measurement tuning for the LBC correlations (Lohrenz et al., 1964) was done by changing the critical volume parameter for all the PS. After the tuning process, the quality of the match was validated with the Hoffman plot (Hoffman et al., 1953), showing a good linear trend (see Figure 2). A summary of the tuned properties is given in Table 1 and Table 2. A comparison of the experimental and simulated PVT data is shown in Figure 3.

<table>
<thead>
<tr>
<th>Table 3: Slim-tube properties from the laboratory experiment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Length, (cm)</td>
</tr>
<tr>
<td>Inside diameter, (cm)</td>
</tr>
<tr>
<td>Grain type</td>
</tr>
<tr>
<td>Grain size, (mm)</td>
</tr>
<tr>
<td>Porosity, (%)</td>
</tr>
<tr>
<td>Permeability, (mD)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Table 4: Reported Oil Recoveries for each CO₂ injection step</th>
</tr>
</thead>
<tbody>
<tr>
<td>Injection Pressure, bar</td>
</tr>
<tr>
<td>--------------------------</td>
</tr>
<tr>
<td>150</td>
</tr>
<tr>
<td>175</td>
</tr>
<tr>
<td>190</td>
</tr>
<tr>
<td>210</td>
</tr>
<tr>
<td>220</td>
</tr>
<tr>
<td>240</td>
</tr>
</tbody>
</table>

![Figure 4: MMP determination from the laboratory slim-tube experiment](image)

![Figure 5: Standard Slim-tube experimental setup](image)
3.3. Slim-tube experiment

The slim-tube test was conducted by injecting CO\(_2\) through the 20.7 m long coil tube with the inside diameter (ID) of 0.395 cm, initially saturated with the recombined oil. The properties of the slim-tube are given in Table 3. The tube was prepacked with quartz sand (120 - 230 mesh, 0.125 - 0.075 mm). A total of 6 injection pressures were reported where 1.2 slim-tube’s pore volumes (PV) of CO\(_2\) were injected. Two injection rates were used during the test. The first rate of 3 cm\(^3\)/h was used until the injected amount of CO\(_2\) reached the value of 0.7 PV and then the rate was doubled to a value of 6 cm\(^3\)/h and kept until the final value of 1.2 PV injected CO\(_2\) was reached. The produced volumes of oil and gas were measured and collected prior the chromatographic analysis.

The outflow and CO\(_2\) breakthrough was observed both on the sight glass, exhibiting the potential flow of bubbles, as well as on the gasometer.

MMP estimation from the laboratory slim-tube experiment is determined at the intersection of the two trend lines on oil recovery versus injection pressure chart, yielding the MMP value of 193.0 bar at 95.34% oil recovery (see Figure 4). The overall recoveries for each injection step are given in Table 4.

3.4. Slim-tube numerical model

A Numerical 1D compositional model was created. For a base case model, a grid block of 500x1x1 cells was used. This case included the same CO\(_2\) injection rates at reservoir conditions (RC) were used as in the experiment (3+6 cm\(^3\)/h). Relative permeabilities for all of the injection pressure steps were set to an “X shape” type curve, starting from the origin and ending at one. Binary interaction parameters for the PS-CO\(_2\) pairs were not fine-tuned meaning they were kept at a value of 0.15. The base case model properties are given in the Table 5.

In order to inspect the impact of varying the number of cells, CO\(_2\) injection rates, heterogeneity regarding the porosity and permeability, relative permeability and different BIPs, various models with different properties were created and simulated.

The dimensions of the grid were fixed but the number of cells was altered in order to quantify the effect on MMP prediction and oil recovery. Slim-tube properties regarding the dimensions, porosity and permeability values from Table 3 were also used in the simulation model.

4. Results and discussion

In order to inspect and quantify the impact of different parameters (number of cells, injection rates, BIPs and relative permeability), various scenarios were tested. The results for the MMP determination with respect to the experimental data from a base case model can be seen in Figure 6. Overall MMP prediction is good, giving the MMP value of 198.4 bar which is 5.4 bar higher than the experimental MMP. The Oil recovery for the simulated MMP is lower, resulting in a total value of 88.3% oil produced.

<table>
<thead>
<tr>
<th>Number of Cells</th>
<th>500</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO(_2) injection Rate at RC</td>
<td>3 cm(^3)/h until 0.7 PV, 6 cm(^3)/h until 1.2 PV CO(_2) injected</td>
</tr>
<tr>
<td>BIP PS-CO(_2)</td>
<td>0.15</td>
</tr>
<tr>
<td>Relative Permeability</td>
<td>X shape</td>
</tr>
<tr>
<td>Porosity, (%)</td>
<td>44.2, single value</td>
</tr>
<tr>
<td>Permeability, (mD)</td>
<td>5056, single value</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>BIP</th>
<th>MMP, (bar)</th>
<th>Oil Recovery, (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.15</td>
<td>198.37</td>
<td>88.30</td>
</tr>
<tr>
<td>0.14</td>
<td>197.92</td>
<td>91.23</td>
</tr>
<tr>
<td>0.13</td>
<td>197.02</td>
<td>93.81</td>
</tr>
<tr>
<td>0.12</td>
<td>195.74</td>
<td>95.99</td>
</tr>
<tr>
<td>0.11</td>
<td>194.06</td>
<td>97.63</td>
</tr>
</tbody>
</table>
tion of the interactions between the hydrocarbon components and the CO₂ in the swelling test but the oil recovery in the simulated slim-tube test was slightly underestimated. In order to try to improve the prediction of the cumulative oil recovery, the BIP’s were slightly altered. As can be seen from Figure 9 and Table 6, the closest MMP prediction with respect to the oil recovery compared to the experimental MMP data is using the BIP value of 0.12.

After the BIP fine-tuning, considering the case where the BIP used was 0.12, it was evident from Figure 9 that the simulation results for the oil recovery at 150 bar injection pressure were too high in comparison with the experimental data. Standard Corey equations for the oil relative permeability (Brooks and Corey 1964) were used to generate a slightly different curve. The Corey exponent used for the oil phase was 2 while the exponent for the gas phase (CO₂) was unchanged, meaning it was
1. Good matching with the experimental value is shown in Figure 10.

The porosity and permeability heterogeneity impact on the simulation results was compared with a homogeneous base case model (see Figure 11). A log-normal distribution was used, with several mean and variance values. The heterogeneous model showed no evidence of any difference compared to the base case model. This can be addressed to the nature of the 1D model, i.e. the nature of the slim-tube experiment, where viscous fingering due to heterogeneity is intentionally avoided.

5. Conclusions

Throughout this work, different parameters were quantified to account for the effect on the overall MMP estimation by numerical simulation of the slim-tube experiment in order to potentially produce a reliable simulation model, capable of replacing the expensive and complex experimental procedures. Besides, this approach becomes a good routine to quality check the EOS and to perform the fine-tuning before using the EOS on a full field reservoir model.

The results of the experimental PVT study were matched to obtain the equation of state for CO₂-EOR compositional simulation. A Modified SRK equation of state showed the best match with the relevant PVT laboratory data and MMP prediction from the slim-tube numerical model. For the fluid composition studied, by applying the trend line intersection method, it is possible to obtain a good estimation of the MMP value with slightly underestimated oil recovery. However, considering the
Figure 9: The impact of BIP fine-tuning on MMP and oil recovery

Figure 10: The impact of altered relative permeability at 150 bar pressure step

Figure 11: Comparison of homogeneous and heterogeneous models. The data obtained through the heterogeneous model is represented with cross type marks while the lines represent the values from a homogeneous base case model.

cases where the intersection cannot be unambiguously determined, the oil recovery criterion (usually 94% or 95%) has not been validated. The underestimation of oil recovery in a slim-tube simulation has been observed by various authors in literature, indicating that more data should be examined. In addition, it is clear that the key miscibility controlling parameters are found in the PVT experiments and its implementation in the EOS.

In terms of the recommendations and restrictions regarding the simulation model parameters (number of cells, flow rates, heterogeneity), a model comprising of 500 cells should provide reliable results with a fast runtime. Flow rates used in the simulation should be around 5 cm³/h in order to have an optimal time-step. The heterogeneity of porosity and permeability does not have any effect on the simulation outcome. Relative permea-
bility can possibly slightly affect the final MMP estimation. Non-miscible relative permeability should be considered for the lower injection pressures, further away from the MMP zone, where miscible conditions are not yet established.

It is evident that the simulation model of the slim-tube experiment should be tested and compared to other slim tube experiments utilizing different fluid models (EOS).

6. References


