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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, CO_2 injection

1. Introduction

CO_2-EOR is an attractive miscible process in which CO_2 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 CO_2 injection conditions. Since it is a function of residual and critical oil saturation $E_D = f(S_{or}, S_c)$, properties of gaseous and liquid phases will change with the distance from the injector to the producer wells. When CO_2 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 CO_2 phase starts to flow several times faster than the oil phase, increasing the relative permeability to CO_2 phase in the flowing pathways. The effect of swelling can be observed in the laboratory by successive addition of CO_2 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 CO_2 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 CO_2 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 CO_2 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 Ivanić 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 CO_2 to

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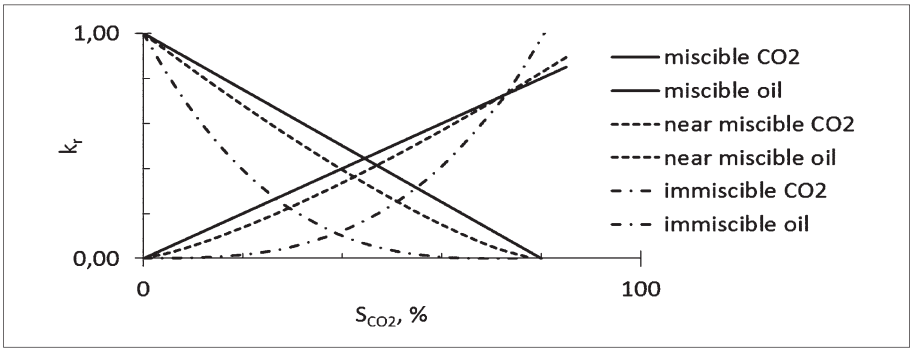

Figure 1: General shape of relative permeability curve at miscible, near miscible and immiscible conditions.

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_{5+} molecular weight and C_{2+} 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 accordance 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 CO_2 – 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 CO_2 displacement at different pressures. They concluded that immiscible displacement by CO_2 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 CO_2 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 CO_2-oil mixtures, swelling factors and solubility of CO_2 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 CO_2-oil system and recommended data from multiple-contact before single-contact experiments be used in determining phase-behavior models for CO_2 flooding simulations.

Wang (**1982**) showed by visual observations at specially designed equipment, that miscible, semi-miscible and immiscible displacement exist simultaneously during CO_2 flood. He concluded that oil recovery cannot be the only criterion for determining the MMP and proposed guidelines for choosing optimal CO_2 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 CO_2 injection. They observed phase composition and density change during CO_2 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 paraffinicity 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)**:

$$k_{ro} = \left(\frac{S_o - 0.15}{1 - 0.15} \right)^2 \tag{1}$$

and

$$k_{rg} = \left(\frac{S_g - 0.04}{1 - 0.19} \right)^2 \tag{2}$$

Where:

S_o, S_g – oil and gas saturations

k_{ro}, k_{rg} – 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 CO_2, 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

Comp	Comp (mol %)	MW	SG	Tc (°C)	Pc (bar)	AF	A	B	Vcrit (m^3/kg mol)	Vol. Shift	P-chor	Tb (°C)
N2	0.094	28.01	1.026	-147.3	33.92	0.039	0.42748	0.08664	0.0898	-0.1540	60.4	-195.75
CO2	0.462	44.01	1.101	30.9	73.98	0.239	0.42748	0.08664	0.0939		78.0	-78.45
C1	33.246	16.04	0.415	-82.5	46.41	0.011	0.42748	0.08664	0.0992	-0.1540	70.0	-161.55
C2	3.921	30.10	0.546	32.1	48.84	0.099	0.42748	0.08664	0.1483	-0.1002	115.0	-88.55
C3	3.110	44.10	0.585	96.7	42.57	0.153	0.42748	0.08664	0.2030	-0.0850	155.0	-42.05
C4	2.833	58.10	0.600	151.8	37.97	0.199	0.42748	0.08664	0.2550	-0.0641	200.0	-0.45
C5	2.808	72.20	0.630	196.4	33.75	0.251	0.42748	0.08664	0.3040	-0.0418	245.0	36.05
C6	2.783	86.20	0.664	234.5	30.32	0.299	0.42748	0.08664	0.3700	-0.0147	282.5	68.75
C7::C13	7.242	98.55	0.717	251.6	30.17	0.315	0.42748	0.08664	0.7492	0.1700	462.8	102.30
C14::C19	13.601	135.84	0.762	317.3	24.83	0.416	0.42748	0.08664	0.8740	0.1800	659.3	166.53
C20::C25	14.290	206.65	0.807	407.7	17.84	0.612	0.42748	0.08664	0.9365	0.2200	802.2	266.06
C26::C32	10.414	319.83	0.849	502.5	12.19	0.917	0.42748	0.08664	0.9989	0.2400	950.9	381.43
C33::C46	5.195	500.00	0.889	597.4	8.43	1.201	0.42748	0.08664	1.2486	0.3800	1158.0	502.70

Table 2: List of Binary Interaction Parameter used in the EOS

	N_2	CO_2	C1	C2	C3	C4	C5	C6	PS-1	PS-2	PS-3	PS-4	PS-5
N2													
CO2	0.02		0.12	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
C1	0.06	0.12		0.00	0.00	0.00	0.00	0.00	0.06	0.08	0.09	0.11	0.14
C2	0.08	0.15	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C3	0.08	0.15	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C4	0.08	0.15	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00
C5	0.08	0.15	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00
C6	0.08	0.15	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00
PS-1	0.08	0.15	0.06	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00
PS-2	0.08	0.15	0.08	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00
PS-3	0.08	0.15	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00
PS-4	0.08	0.15	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00
PS-5	0.08	0.15	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	

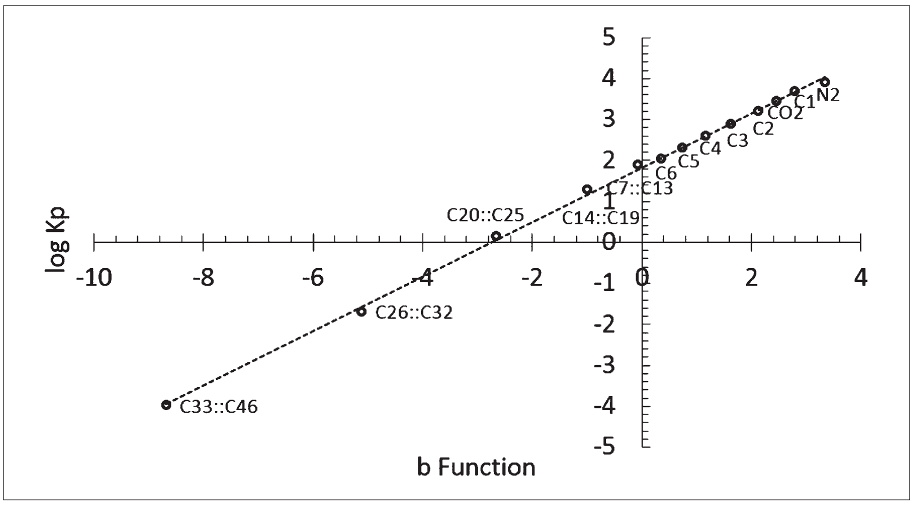

Figure 2: Hoffman plot for K-values quality check using the DL test EOS results for 81 bar pressure step

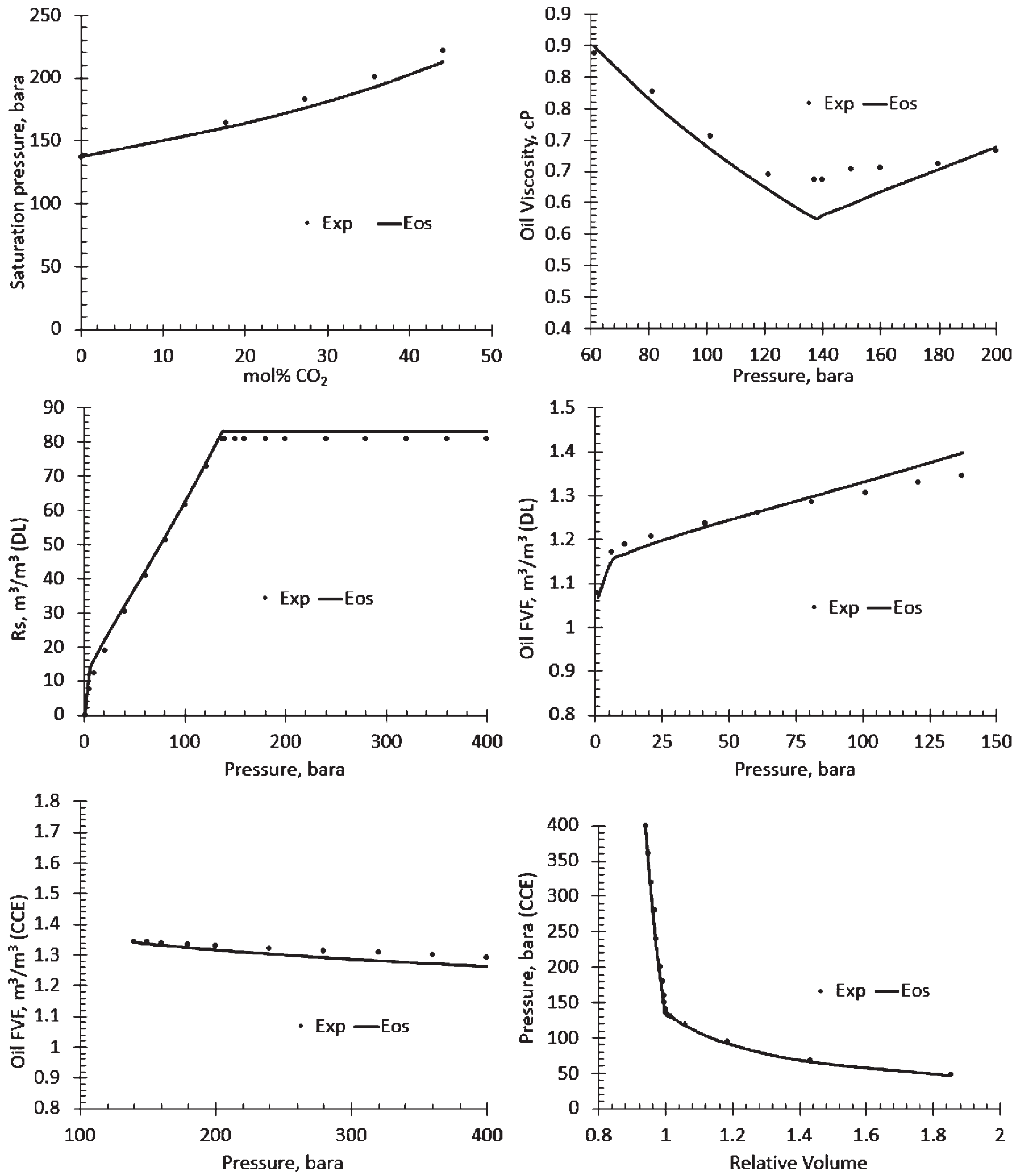

Figure 3: Comparison of experimental and simulated PVT data

analysis at several pressures and found that the effect of near miscibility is more pronounced for the CO_2 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. CO_2–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 CO_2-EOR. However, the slim-tube experiment connects a volume of injected CO_2 with oil recovery. **Wolsky and Jankowski** (**1986**) developed a techno-economic framework to estimate the feasibility of CO_2 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 CO_2 supply and target additional recovery are oil price and internal rate of return. **Martin and Taber** published (**1992**) a figure that relates the maximum CO_2 cost for CO_2 flooding with oil price and rate of return. Even though the operating costs are significantly different

Table 3: Slim-tube properties from the laboratory experiment

Length, (cm)	2070
Inside diameter, (cm)	0.395
Grain type	Quartz sand
Grain size, (mm)	0.125-0.075
Porosity, (%)	44.2
Permeability, (mD)	5056

Table 4: Reported Oil Recoveries for each CO_2 injection step

Injection Pressure, bar	Oil Recovery, %
150	68.54
175	87.68
190	91.60
210	95.81
220	95.06
240	95.89

nowadays, the diagram shows a linear correlation between costs, amount of injected CO_2 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 CO_2, 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 m^3/m^3. Oil swelling test with CO_2 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 C_{7+} fractions into 5 pseudo fractions (PS), giving a total of 13 components. Binary interaction parameters (BIP) between the C_1 and PS were used to develop the phase envelope curve. The BIPs regarding the hydrocarbon interaction between nitrogen

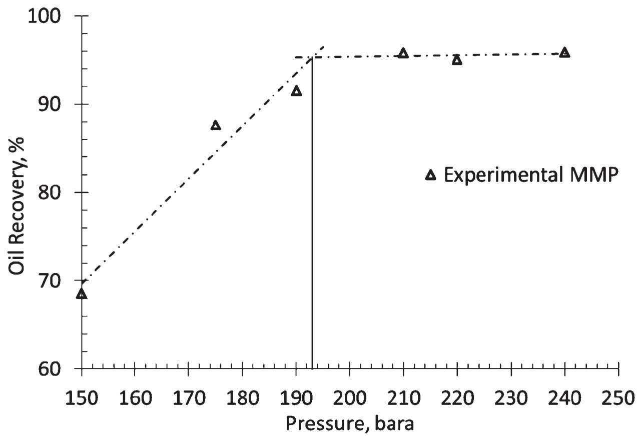

Figure 4: MMP determination from the laboratory slim-tube experiment

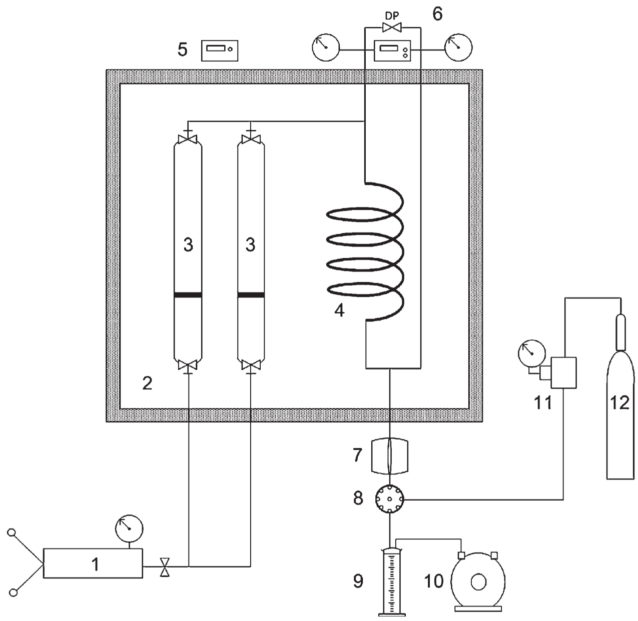

Figure 5: an experimental setup for slim-tube test is shown. Numbers indicate the main components: 1–volumetric displacement pump, 2 – oven, 3 – CO_2 and oil filled cylinders, 4 – slim-tube, 5 – temperature regulation unit, 6 – diff. pressure transducer, 7 – sight glass, 8–BPR valve, 9 – graduated cylinder, 10 – gasometer, 11 – pressure multiplier and 12 – nitrogen bottle.

Figure 5: Standard Slim-tube experimental setup.

and CO_2 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**.

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 500×1×1 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.

Table 5: Properties of the base case model

Number of Cells	500
CO_2 injection Rate at RC:	3 cm^3/h until 0.7 PV, 6 cm^3/h until 1.2 PV CO_2 injected
BIP PS-CO2	0.15
Relative Permeability	X shape
Porosity, (%)	44.2, single value
Permeability, (mD)	5056, single value

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.

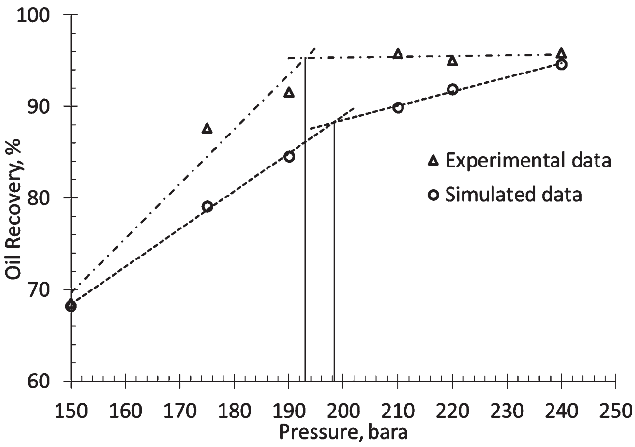

Figure 6: MMP determination from the base case model compared to the experimental data

Base case models with a different number of cells (50 and 2000) were tested. From the given results (see **Figure 7**), it is obvious that for each pressure step no significant difference in the oil recovery is observed for the 500 and 2000 number of cells. The model with 50 cells yielded lower overall oil recovery for each step.

Similarly, sensitivity to injection rates was tested. Flow rates used and compared were 3+6, 2, 7 and 28 cm^3/h (see **Figure 8**). The only flow rate with a more notable difference in the cumulative oil recovery was with 28 cm^3/h. Overall, there is a minor change in the oil recovery between all of the flow rates used.

A BIP value of 0.15 was used in the Base case model EOS for all PS-CO_2 pairs. The EOS made a good predic-

Table 6: BIP Fine tuning results

BIP	MMP, (bar)	Oil Recovery, (%)
0.15	198.37	88.30
0.14	197.92	91.23
0.13	197.02	93.81
0.12	195.74	95.99
0.11	194.06	97.63

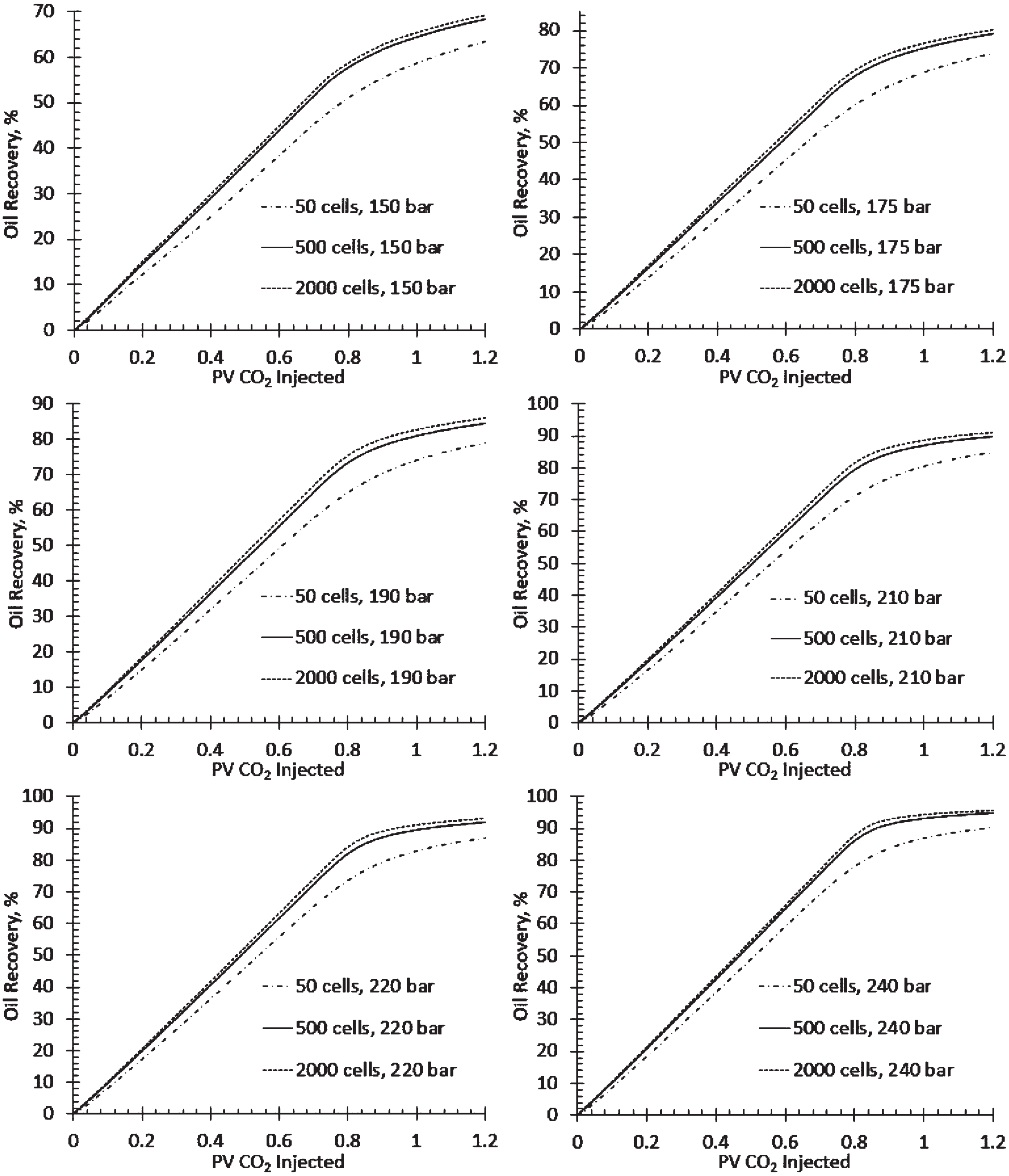

Figure 7: The results from a cell number sensitivity analysis.

tion of the interactions between the hydrocarbon components and the CO_2 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 (CO_2) was unchanged, meaning it was

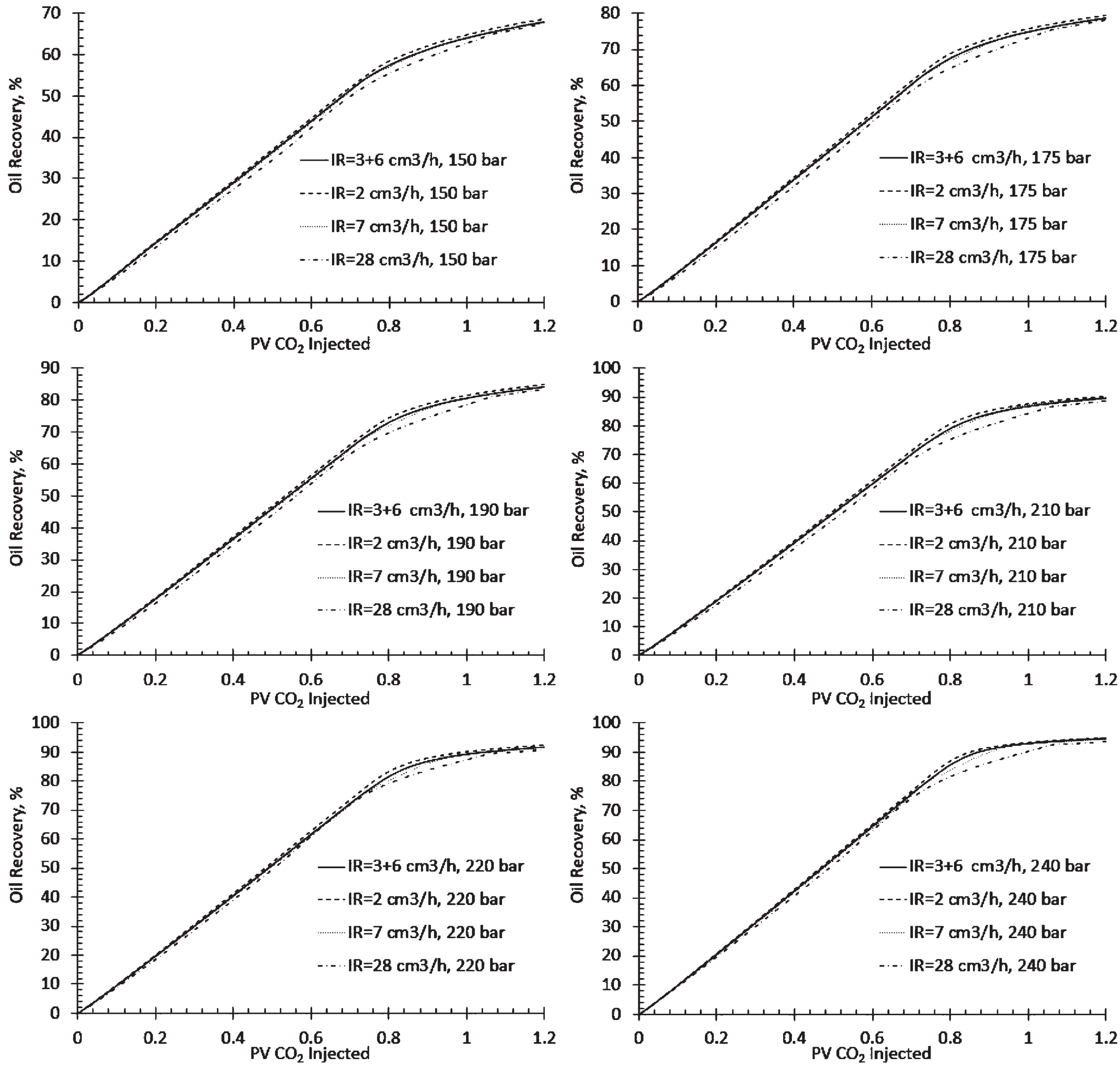

Figure 8: The results from an injection rate (IR) sensitivity analysis.

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 CO_2-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

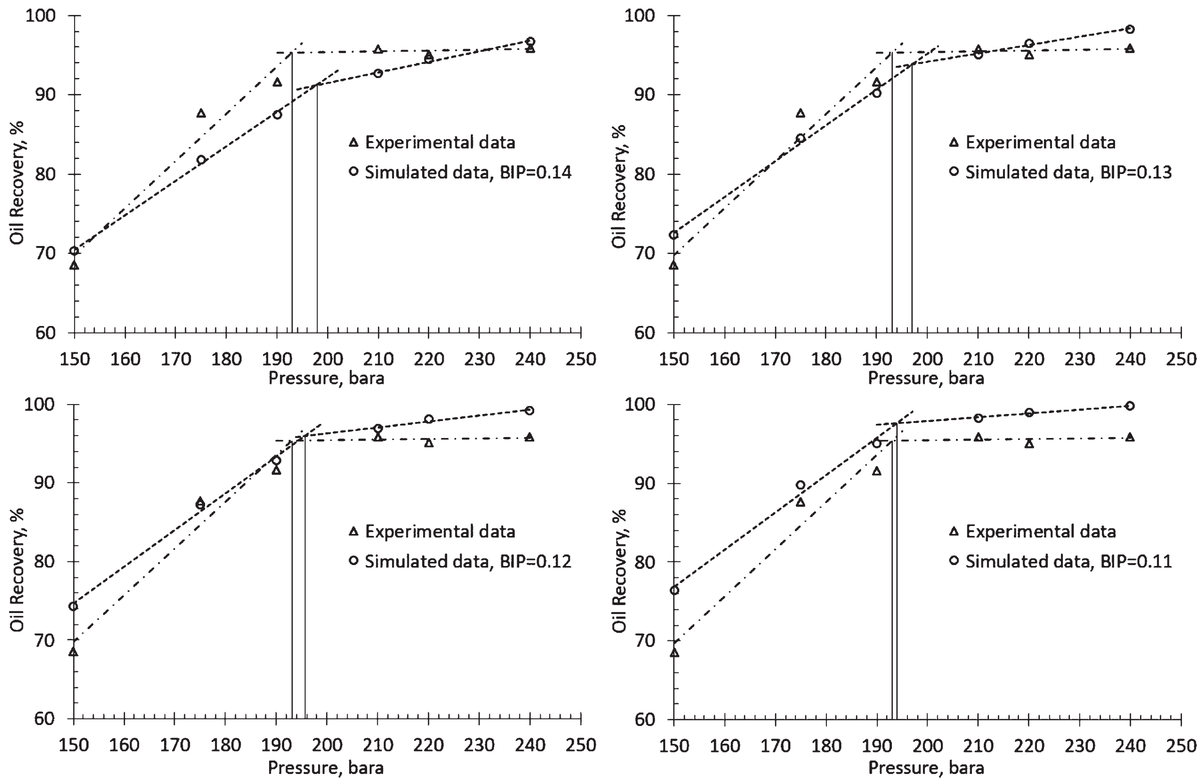

Figure 9: The impact of BIP fine-tuning on MMP and oil recovery

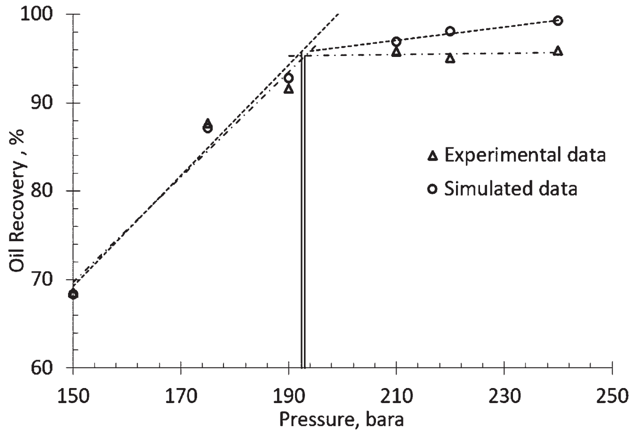

Figure 10: The impact of altered relative permeability at 150 bar pressure step

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 run-time. Flow rates used in the simulation should be around 5 cm^3/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-

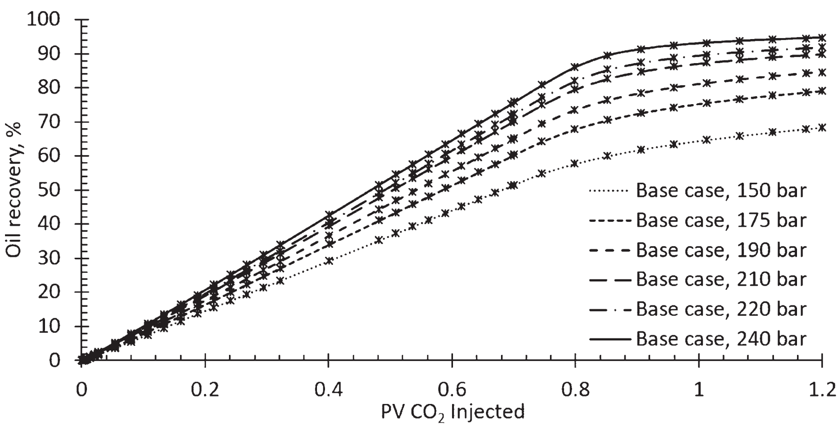

Figure 11: Comparison of homogeneous and heterogeneous models. The data obtained through the heterogeneous model is represented with cross type marks while the lines represent the values from a homogeneous base case model.

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).

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