Features concerning capillary pressure and the effect on two-phase and three-phase flow

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Abstract

The effect of capillary pressure related to immiscible WAG (Water Alternate Gas) is studied by use of a numerical simulator. The capillary pressure is found to have a significant effect on the pressure gradient and the total oil production both in two-phase and three-phase flow situations. When the capillary pressure is included in the simulation the total oil production is considerably lower than when the capillary pressure is neglected. Experimentally measured two-phase capillary pressure was used as input to the numerical simulator. The two-phase capillary pressure was further used to estimate three-phase flow, related to WAG processes.

A network model was applied to generate a consistent set of two-phase and three-phase capillary pressure. The network model was anchored to measured two-phase data, and three-phase capillary pressure was constructed. The gas-oil and mercury capillary pressure anchored the pore structure parameters, while water-oil capillary pressure anchors the wettability parameters in the network model.

The network model quantifies the difference between three-phase and two-phase capillary pressure, and in the cases studied the difference between two-phase and three-phase capillary pressure was significant.

Introduction

The oil recovery by WAG has been attributed to improved sweep, especially recovery of attic oil or cellar oil by exploiting the segregation of gas to the top or accumulation of water towards the bottom. Possible improved microscopic efficiency in three-phase zones of the reservoir may come as an added benefit of the WAG injection. The WAG process has been extensively applied in recent years[1-2].

WAG three-phase flow incorporates the effect of trapped gas and mobility for secondary processes (ex. water after gas injection). The oil recoveries from gas, water, and WAG core displacements have in the literature been compared, and WAG specific models have been developed that include the features observed[3-5].

In many cases capillary pressure is neglected when performing numerical simulations. The argument behind eliminating capillary pressure is to simplify the model and also the belief that capillary pressure is of less importance for the problem analysed, or that there are no experimental capillary pressure data available. This work tries to show the consequence of neglecting capillary pressure.

First a summary of the experimental data is given. The effect of capillary pressure on two-phase flow and the effect on three-phase flow are also shown. A network model is anchored to the two-phase data and is further used to predict three-phase capillary pressure.

Results and discussion

Experiment: Data from a North Sea reservoir was used in this work. Several flow experiments were performed on a core at reservoir conditions. One experiment started with gas injection and was followed by water injection, G1W2. Figure 1 shows the oil-, water- and gas-production from this injection sequence. The other injection sequence started with water injection and was followed by gas injection, another water injection and finally a gas injection period, W1G2W3G4. Note that the oil production in the G2 period increases in two steps. This could be due to double displacement in the early phase of the G2 injection period and direct displacement in the later phase. Figure 2 shows the production data for this experiment. Some key numbers from the experiment is listed in table 1.

Capillary pressure and wettability were measured on a core plug with similar qualities as the composite core used in the flow experiments. The wettability was mixed-wet large; large pores oil-wet and small pores water-wet. The capillary pressure curves were matched with a correlation function[6] and scaled to match the endpoints from the flow experiments. The capillary pressure curves used as input to the simulation is shown in figures 3 and 4. Mercury data was also available, but for a different core than the one used for the capillary pressure and wettability measurements.

Effect of capillary pressure on two-phase flow: The effect of capillary pressure on flow was studied by use of the Eclipse black oil simulator[7]. The two-phase cases, G1 and W1, were first matched without capillary pressure included; Pc = 0. The relative permeability curves were adjusted until a satisfactory match of the experimental data was obtained. This match can be seen as the grey line in figures 5 and 6. The next step was to include the capillary pressure curves to see the impact the capillary pressure had on the flow performance. The total oil production was significantly lower when the capillary pressure had been included, seen as the dashed black line in figures 5 and 6. In order to get a match of the experimental data with capillary pressure included the relative permeability curves had to be adjusted. The new match with capillary pressure included is seen as the solid black line in figures 5 and 6. The relative permeability of oil had to be increased and the relative permeability of the injected fluids, gas and water, had to be reduced to get a match. The relative permeability curves for the match without capillary pressure is shown as the dashed lines in figures 7 and 8, and the relative permeability from the match with capillary pressure included is shown as the solid lines. The difference between the relative permeability curves is significant.

The match of the total oil production for the initial gas injection experiment is better with capillary pressure included. The shape of the simulated total oil production is closer to the experimental data. The match of the injection pressures is also better when capillary pressure is included. Figures 9 and 10 show the injection pressure for the match without capillary pressure as the grey line. The case with included capillary pressure and no other adjustments is seen as the dashed black line. The solid black line represents the match with capillary pressure included and is closer to the experimental data for both G1 and W1, see figures 9 and 10.

Effect of capillary pressure on three-phase flow: The relative permeability curves found from the two-phase matching was also used for the three-phase simulation. For three-phase flow a weighted average of the input two-phase capillary pressure curves, as suggested by Killough[8], is used by the simulator.

The relative permeability curves for the two-phase match without capillary pressure, dashed lines in figures 7 and 8, were used as input to the three-phase simulation without capillary pressure. The injection sequence W1G2W3G4 was matched, see grey line in figure 11. The match was fairly good but the increase in oil production from the G2-injection was too late, and the two step increase in the oil production in the G2 period was not easy to match perfectly. When capillary pressure was included it had an impact on the oil production curve, see the dashed black line in figure 11.

In order to get a match with capillary pressure the relative permeability from the two-phase match with capillary pressure, solid lines in figures 7 and 8, were included. This match is shown as the solid black line in figure 11. The match of the increased oil production at the start of the G2 period is closer to the experimental data. It was also possible to match the two step increase in oil production. The match of the injection pressures is seen in figure 12. The match with capillary pressure, solid black line, is closer to the experimental data.

Three-phase capillary pressure: In the simulation work a weighted average of the two-phase capillary pressures were used for three-phase flow. This part of the work focused on finding out if this was a good approximation. A network model developed at Heriot-Watt[9] was used. The network model was anchored to the two-phase data and the three-phase capillary pressure curves were predicted.

Network model: The network model is based on invasion percolation and the flow is dominated by capillary forces. The "3R approach" is used[10] in the modelling. The network model consists of a three-dimensional network of pores with radius r. The distribution of r is taken from a given minimum and maximum radius together with the pore size distribution. The capillary pressure (eq. 1), the volume (eq. 2) and conductance (eq. 3) are all functions of the radius.

$$P_c \propto \frac{1}{r} \tag{1}$$

$$V(r) \propto r^{\nu} \tag{2}$$

$$g(r) \propto r^{\lambda} \tag{3}$$

The expression for Pc is consistent with the Young-Laplace equation. The volume exponent is normally in the range of 0 to 2, and the conductance exponent is normally in the range of 1 to 4.

The contact angles between oil and water, $\cos \theta_{ow}$, gives the wettability. The transition radius between oil-wet and water-wet pores, *r(wet)*, must also be given when describing the case of mixed-wet large. The degree of films and layers is also important to include. This is done by giving threshold values for the contact angles, where layers are formed above these values.

Anchoring: If representative mercury data is available it can be used to fix the minimum and maximum pore radius together with the pore size distribution. In this case the mercury data could only provide an estimate of the *r(max)* and the pore size distribution.

The gas-oil capillary pressure is relatively independent of the wettability. This curve can therefore be used to find the pore properties. The threshold pressure depends strongly on *r(max)*, the maximum pressure depends on *r(min)* and the shape of the curve depends on the pore size distribution. The parameters found in this stage are used as input to the match of the oil-water capillary pressure. Tuning the threshold for oil film around gas produces the correct endpoint saturation.

The oil-water capillary pressure is used to determine the wettability state. The wettability is described by the contact angle between oil and water. In this case of mixed-wet large the radius where the wettability changes between oil-wet and water-wet, *r(wet)*, also has to be established. The degree of films and layers has to be tuned to get the correct endpoint saturation value.

After matching the oil-water capillary pressure the wettability data found are used as input in the previously matched gas oil case to check if the match is affected by the wettability. In this case the gas-oil curve was a bit influenced by the wettability and some small adjustments had to be made. A couple of iterations are usually necessary to match both the gas-oil and oil-water capillary pressure with the same set of parameters. The workflow used can be seen in figure 13.

The match of the gas-oil and oil-water capillary pressure can be seen in figures 14 and 15. The grey line represents the measured data and the black line is the match from the network model. The match of the gas-oil curve is very good, and the match of the oil-water curve is reasonably good.

Prediction of three-phase capillary pressure: After matching the two-phase capillary pressure curves, the parameters found are used as input to the prediction of three-phase capillary pressure. Two injection sequences were executed in the anchored network model. The first was initial gas injection followed by water injection and a third period of gas injection, G1W2G3. The second was initial water injection followed by gas injection and a third period of water injection, W1G2W3.

The three-phase gas-oil capillary pressure curves for the G2 and G3 injection was compared to the two-phase gas-oil capillary pressure, G1. In figure 16 the two-phase capillary pressure, G1, is shown as the black line, and the three-phase capillary pressures G2 and G3 are shown as the grey and dashed black line, respectively. The three-phase G2 capillary entry pressure is approximately twice as high as for two-phase. The three-phase G3 capillary pressure is about a hundred times higher than the two-phase capillary pressure.

The three-phase oil-water capillary pressure for W2 and W3 was compared to the two-phase oil-water curve, W1. In figure 17 the two-phase capillary pressure, W1, is shown as the black line, and the three-phase capillary pressures W2 and W3 are shown as the grey and dashed black line, respectively. The three-phase capillary pressures intersect the x-axis further to the left than the two-phase curve. They behave as more oil-wet like capillary pressure. The negative part of the curves spans over a larger saturation range and has a higher negative value than the two-phase curve.

Conclusions

- The effect of capillary pressure on flow is significant.
- All simulations show that when capillary pressure is included the total oil production is lower than when capillary pressure is neglected.
- The relative permeability of the oil must be increased and the relative permeability of the injected fluid must be reduced to match the measured oil production.
- The shape of the total oil production curve and the injection pressure is better matched to the experimental data when capillary pressure is included.
- The network model used has enough flexibility to match both the gas-oil and the oil-water capillary pressure.
- The approach of anchoring the network model to two-phase capillary pressures generates three-phase capillary pressures that are significantly different.
- The three-phase capillary pressure can not be approximated by a weighted average between the two-phase capillary pressure curves.

Acknowledgement

We would like to acknowledge Rink van Dijke, Heriot-Watt University, for discussions and support regarding the network modelling.

References

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Table 1: Summary of experimental data

Experiment	Swi	Flooding rate [cm³/min]	Sw^e	Sg^e	Sor^e	kri^e (Sor^e)
G1	0.32	0.50	0.32	0.57	0.11	0.08
W2		0.50	0.68	0.21*	0.11	0.11
W1	0.29	0.55	0.86	0	0.14	0.30
G2		0.26	0.49	0.45	0.06	0.03
W3		0.49	0.65	0.31*	0.04	0.01
G4		0.20	0.45	0.51	0.04	0.03

*Trapped gas

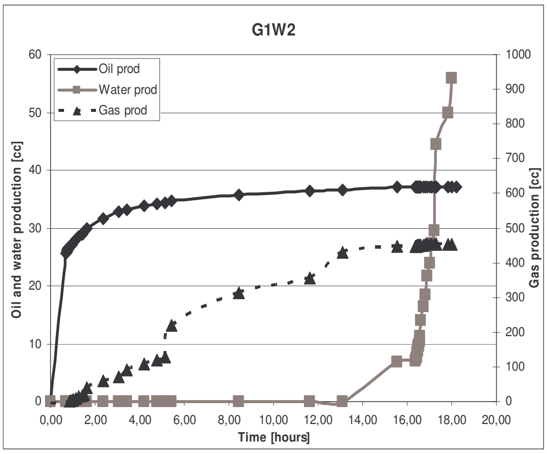

Fig. 1: Experimental data for G1W2.

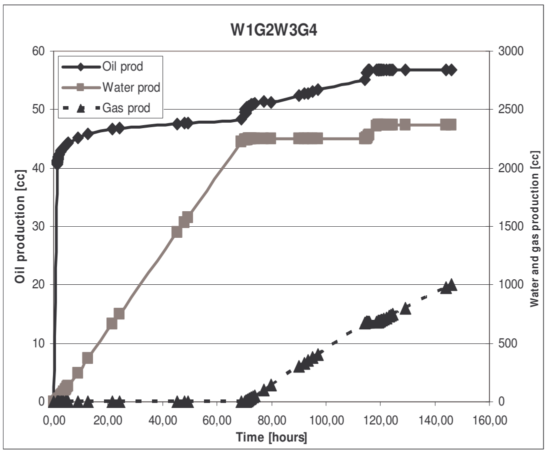

Fig. 2: Experimental data for W1G2W3G4.

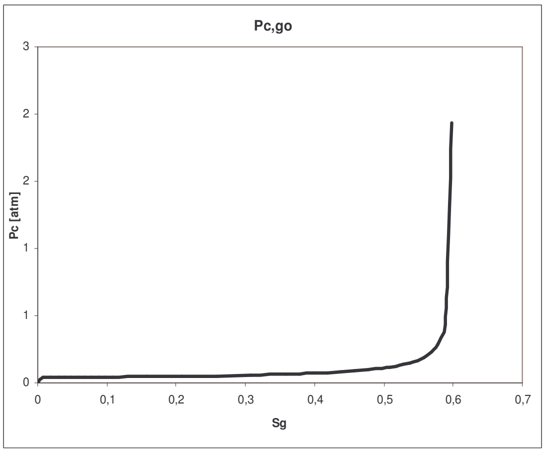

Fig. 3: Capillary pressure for the gas-oil process.

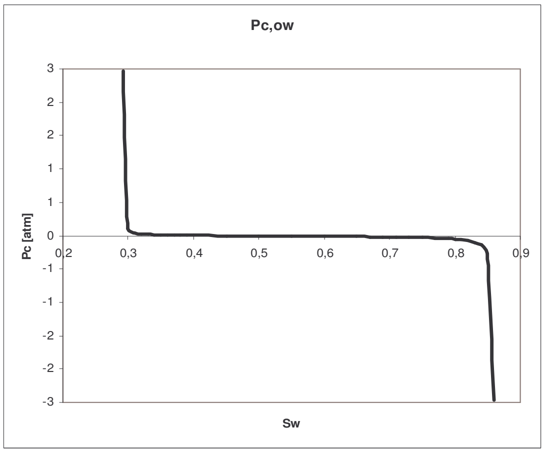

Fig. 4: Capillary pressure for the oil-water process.

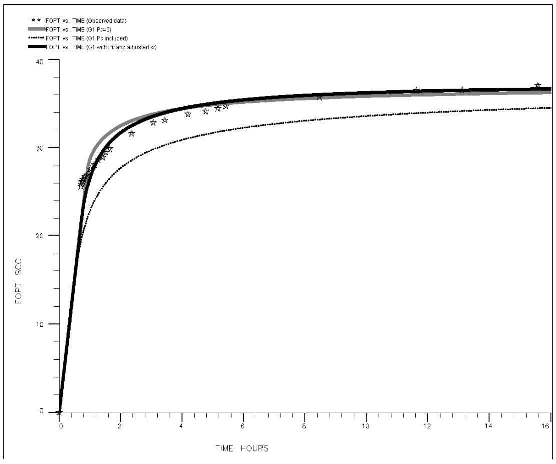

Fig. 5: Match of simulated total oil production with experimental oil production for G1.

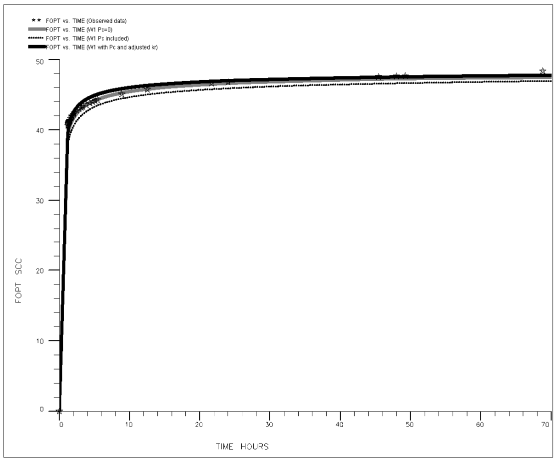

Fig. 6: Match of simulated total oil production with experimental oil production for W1.

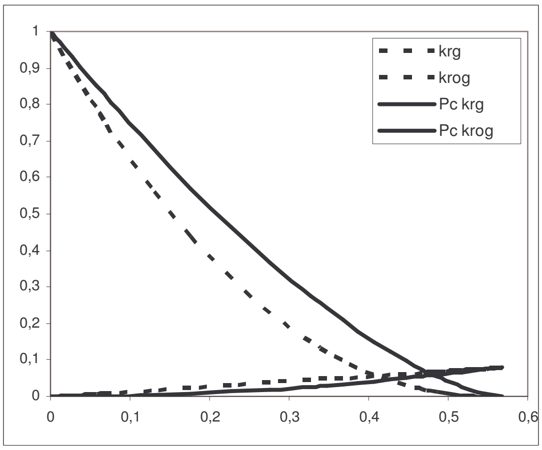

Fig. 7: Comparison of the relative permeabilities for match of the simulations with and without capillary pressure for G1.

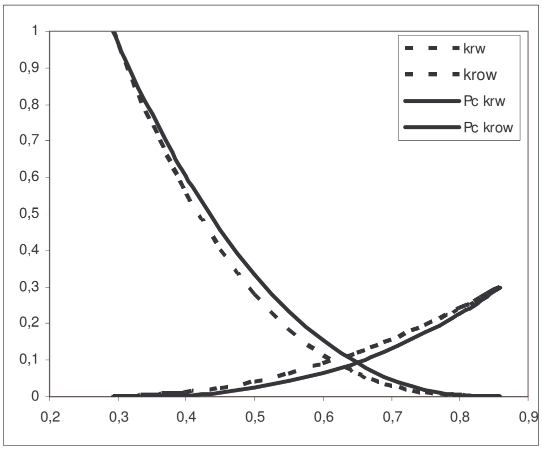

Fig. 8: Comparison of the relative permeabilities for match of the simulations with and without capillary pressure for W1.

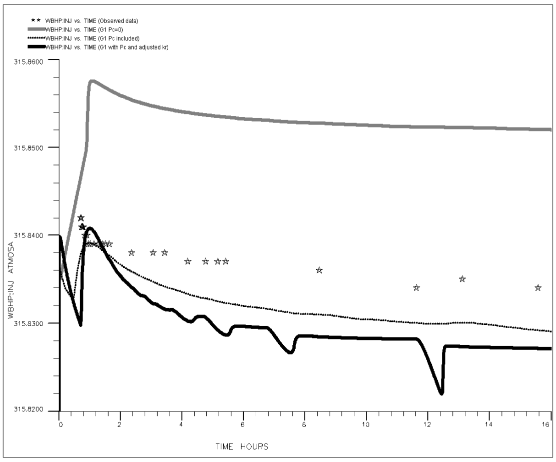

Fig. 9: Match of the injection pressure with experimental pressure for G1.

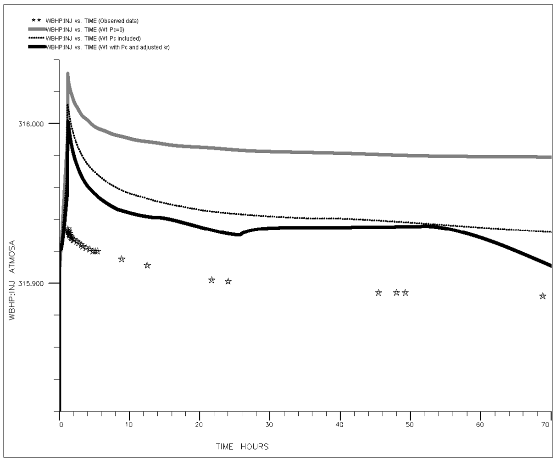

Fig. 10: Match of the injection pressure with experimental pressure for W1.

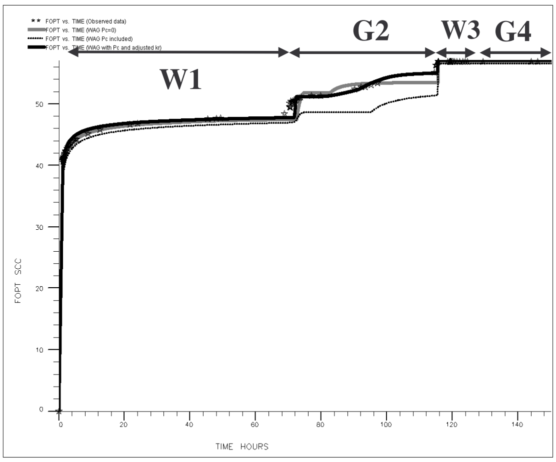

Fig. 11: Match of simulated total oil production with experimental oil production for WAG (W1G2W3G4).

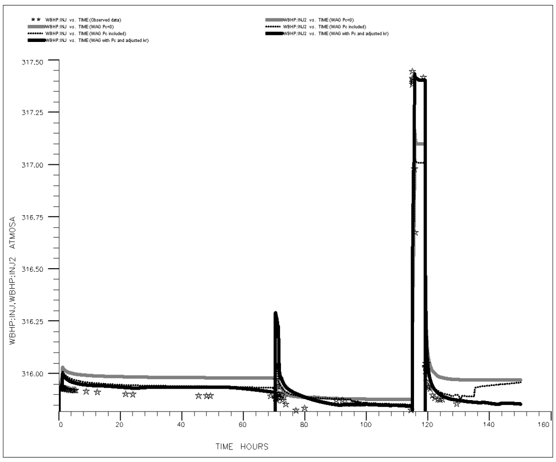

Fig. 12: Match of the injection pressure with experimental pressure for WAG (W1G2W3G4).

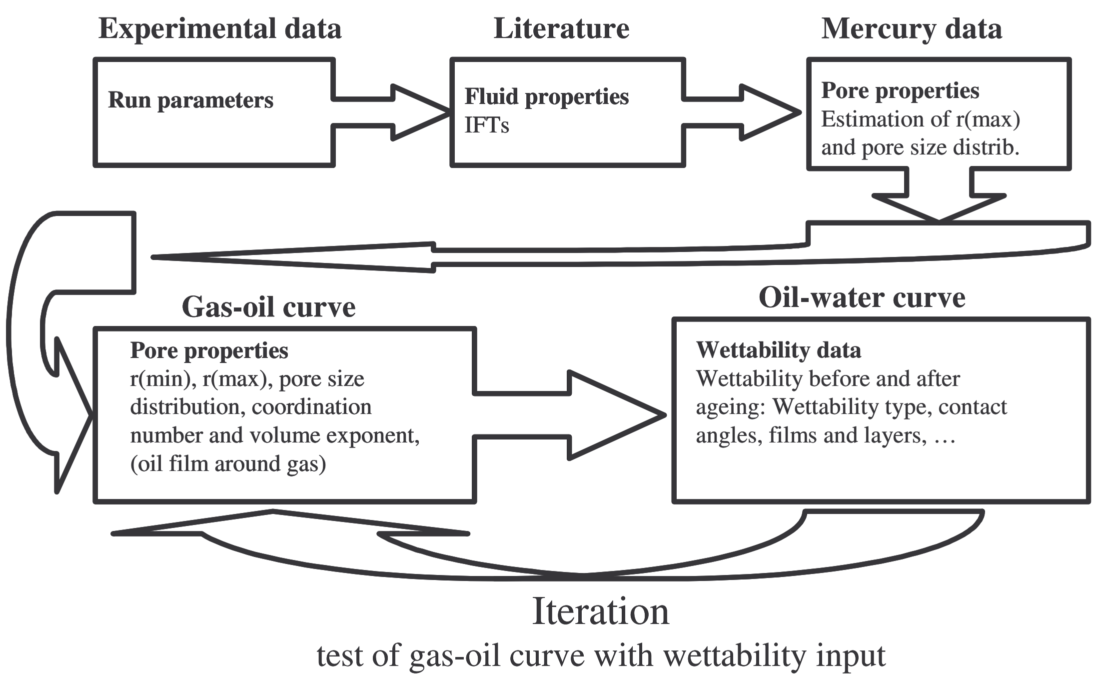

Fig. 13: Workflow for match of capillary pressure with the network model.

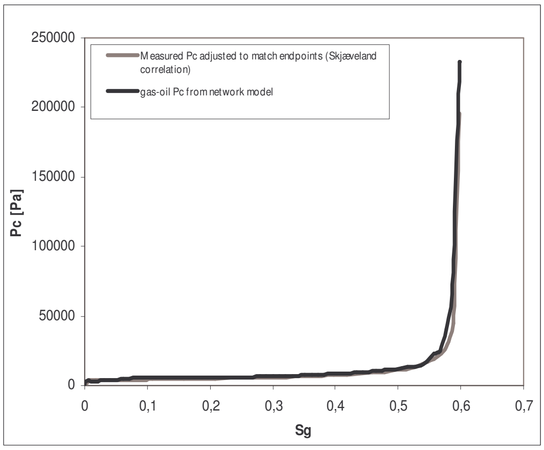

Fig. 14: Match of Pc for the gas-oil process.

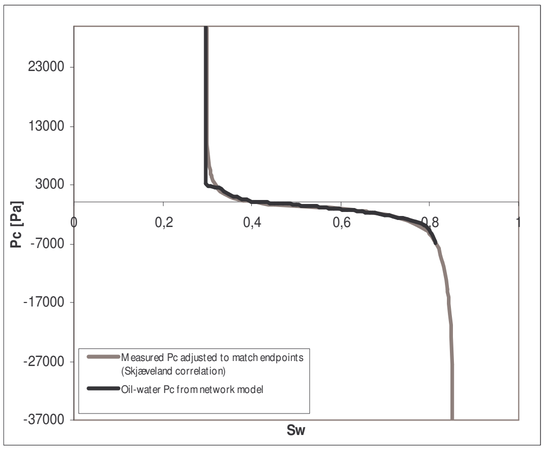

Fig. 15: Match of Pc for the oil-water process.

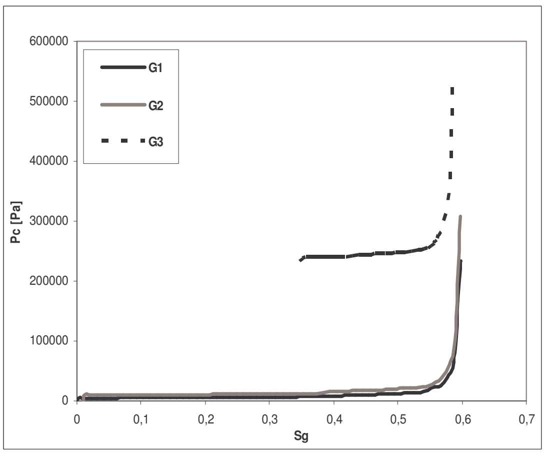

Fig. 16: Prediction of three-phase capillary pressure compared to two-phase capillary pressure for gas-oil.

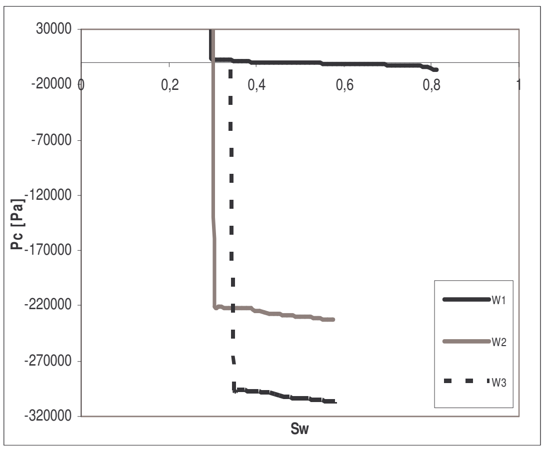

Fig. 17: Prediction of three-phase capillary pressure compared to two-phase capillary pressure for oil- water.