Influence of Capillary Pressure on Estimation of Relative Permeability for Immiscible WAG Processes

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Abstract

Capillary pressure is one of the important parameters when describing flow in porous media. This parameter is nevertheless in some cases neglected, especially if no reliable measured data is available.

The purpose of this work was to investigate how capillary pressure influences reservoir behaviour. The key question has been if the capillary pressure could be neglected when simulating reservoir production or if the capillary pressure has significant impact on the production performance. This problem was addressed by comparing the production from simulations of core floods without capillary pressure to simulations with capillary pressure included. A match without capillary pressure included was achieved by tuning the relative permeability curves. Then capillary pressure was introduced while keeping the other parameters identical. The total oil production was significantly lower when capillary pressure was included. The relative permeability of oil had to be increased and the relative permeability of the injected fluids had to be reduced to get a new match with capillary pressure.

The relative permeability for the match with zero capillary pressure was then compared to the relative permeability for the match with capillary pressure included. The difference in relative permeability was found to be significant. The relative permeability of oil had to be increased and the relative permeability of the injected fluids had to be reduced in the match with capillary pressure included. It was concluded that the capillary pressure had an important

impact on production behaviour and therefore also on history matching of relative permeability. If capillary pressure is not included the relative permeability of oil will be underestimated and the relative permeability of the injected fluids, gas and water, will be overestimated.

Keywords: Capillary pressure, flow, production, recovery, relative permeability, numerical simulation, three-phase,

1 Introduction

Capillary pressure is defined as the pressure difference between immiscible phases. The two-phase gas-oil capillary pressure is the pressure difference between gas and oil, and the two-phase oil-water capillary pressure is the pressure difference between oil and water (Dake, 1978).

In the numerical simulator Eclipse the input data for capillary pressure is the primary drainage curve, i.e. the oil-water capillary pressure curve, and the imbibition curve, i.e. the gas-oil capillary pressure curve (Eclipse ref. 2006.1). For three-phase flow the choice is between using the two-phase capillary pressure curves or a three-phase correlation developed by Killough (1976). Killough's correlation expresses three-phase capillary pressure as a weighted average of the two-phase drainage and imbibition curves.

Conventionally, relative permeability has been calculated by analytical methods where capillary pressure is neglected (Johnson et. al, 1959; Craig, 1971; Honarpour et. al, 1986). In most cases capillary pressure has been neglected also in numerical simulation of multi-phase flow problems. More recent development and application of inverse methods for relative permeability estimation (Vignes, 1993; Skauge et. al, 1997) have made use of capillary pressure in relative permeability determination from experimental data. This approach has made it possible to include estimates of accuracy in derived relative permeability or simultaneous derived relative permeability and capillary pressure for two-phase flow. The effect of capillary pressure related to three-phase flow and estimation of three-phase relative permeability has received much less attention (Dale et. al, 2007). The motivation for this work was to examine whether or not excluding capillary pressure is a viable approximation for immiscible WAG processes.

First a summary of the experimental data will be presented. A description of the core data and a summary of the conditions and results of the flow experiments are included. In the simulation section a description of the input data, relative permeability and capillary pressure, and the grid design is given. Results from the numerical simulation of the experimental data will be provided. First the match of two-phase flow will be presented and then the match of the three-phase flow process. Then some conclusions from the work are proposed.

2 Experimental data

The experimental data used in this study was from a North Sea field. The experiment was performed at reservoir conditions. Two injection sequences were performed. One started with gas-injection and was followed by water-injection, denoted G1W2. The other started with water-injection followed by gas-injection, a second water-injection and a second gas-injection, denoted as, W1G2W3G4. The results from all the core floods are summarized in table 1.

2.1 Core data

The composite core used for the G1W2-injection consisted of three core plugs mounted together. The oil permeability was approximately 324 mD. The average porosity was 0.265 and the composite core length was 22.05 cm. The core used for the W1G2W3G4-injection consisted of four core plugs. The oil permeability was approximately 343 mD. The average porosity was 0.247 and the length was 30.38 cm.

The experiments were performed at reservoir conditions. The pressure was 320 bars and the temperature was 95°C. The fluids used were synthetic formation water, recombined reservoir oil and reservoir gas. Amott (1959) and USBM (Donaldson et. al, 1969) wettability tests were performed on plugs in the well. The results suggested intermediate-wet conditions of the type mixed wet large (Skauge et. al, 2007); large pores are oil-wet.

2.2 Primary gas injection and secondary water injection, G1W2

One of the flooding sequences performed was a primary gas injection followed by a secondary water injection, a G1W2-process. The core holder was placed in a vertical position and the gas was injected at the top, and water was injected at the bottom. This ensured gravity stable displacement. The flow rate was held constant at approximately 0.5 cm^3/min.

The residual oil saturation at the end of the gas injection, Sorg, was 11%, and the endpoint relative permeability of gas to oil, krg^e (Sorg), was measured to be 0.08. The secondary water injection did not give significantly more oil produced and the minimum residual oil, Sorm, was 11%. The trapped gas saturation was measured to be 21%. The production behaviour can be seen in figure 1.

2.3 Sequence of displacements starting with water injection, W1G2W3G4

The next experimental sequence was primary water injection followed by secondary gas injection, a tertiary water-injection and a fourth gas-injection. The core was held in a vertical position and water was injected at the bottom and gas at the top. The flow rates were 0.55 cm^3/min for W1. 0.26 cm^3/min for G2, 0.49 cm^3/min for W3 and 0.2 cm^3/min for G4.

The primary water injection gave a residual oil saturation, Sorw, of 14%, and the endpoint relative permeability of water to oil, krw^e (Sorw), was measured to be 0.3. The secondary gas injection resulted in a residual oil saturation, Sorm(W1G2), of 6%, and the residual oil after the tertiary water-injection was measured to be 4%. No significant amount of oil was produced during the fourth injection period and the minimum residual oil, Sorm, was 4%. The experimental data can be seen in figure 2.

3 Simulations

The black-oil simulator Eclipse 100 was used to match the experimental data. The core was oriented vertically. To avoid capillary end-effects the inlet and outlet grid blocks were divided into ten parts. A dummy grid block representing the outside of the core, with very high permeability and zero capillary pressure, was added at each end.

3.1 Relative permeability

Corey-type curves were chosen for the input relative permeability (Corey, 1954). It was important to be able to change the relative permeability until a satisfactory match was achieved, and Corey-type curves are easy to tune. The gas and water curves were adjusted to match the measured endpoint relative permeabilities, krw^e and krg^e.

3.2 Capillary pressure

Capillary pressure data, Pc, from the same well was available. Data from plugs that had similar properties as the composite cores used for the flooding experiments were chosen. The data was fitted with the Skjæveland et. al-correlation (2000) and adjusted to match the endpoints in the flooding experiment. The capillary pressure curves can be seen in figures 3 and 4.

The three-phase capillary pressure is very difficult to measure and therefore three-phase data are usually not available. In simulation models the two-phase capillary pressure is therefore often used also for three-phase flow. The other option is to use Killough's (1976) correlation for three-phase capillary pressure. The three-phase capillary pressure is then estimated by a weighted average of the two-phase capillary pressure curves, see figure 5.

4 Results and discussion

4.1 Match of two-phase flow - G1

A satisfactory match of the G1 process without capillary pressure was achieved by tuning the relative permeability curves. The G1 match without capillary pressure is shown in figure 6 as the grey line. The experimental data are shown as black stars. When capillary pressure was introduced the total oil production was reduced considerably. The simulation including capillary pressure, but with the same relative permeability as the match without capillary pressure, is shown as a black dashed line.

To get a match with capillary pressure included the relative permeability of the oil had to be increased and the relative permeability of the gas had to be reduced. The simulation with capillary pressure and adjusted relative permeability is shown as a black line in figure 6. The shape of the curve after including the capillary pressure is closer to the experimental data. The match of the pressure in the injector can be seen in figure 7. The differential pressure is closer to the measured data for the matched case with capillary pressure included, represented by the black line in figure 7.

The relative permeability curves used to match the data without capillary pressure and with capillary pressure included are shown in figure 8. The curves with dashed lines are used for the match without capillary pressure, and the curves with solid lines are used for the match with capillary pressure. The difference between the curves is considerable particularly for the oil relative permeability.

The relative permeability had to be modified to compensate for the capillary pressure effect. If relative permeability measured in the laboratory is used as input in a simulator the corresponding capillary pressure must also be included or the simulated production will not be correct.

4.2 Match of two-phase flow - W1

The W1 process was also matched by including the appropriate relative permeability curves, shown as a grey line in figure 9. The experimental data are represented by black stars. The total oil production was reduced when including capillary pressure also in this case, seen as the black dashed line in figure 9.

By increasing the oil relative permeability and reducing the water relative permeability the experimental data was matched, represented by the black line in figure 9. The match of the injection pressure can be seen in figure 10. The match with capillary pressure included is closer to the experimental data.

The comparison between the relative permeabilities, for the simulation without and with capillary pressure included, can be seen in figure 11. The dashed lines represent the relative permeability curves used for the case without capillary pressure. The solid lines are used for the case with capillary pressure. The change in the relative permeability is significant.

4.3 Match of three-phase flow - W1G2W3G4

Two-phase capillary pressure as input to three-phase flow

The WAG-process, W1G2W3G4, is matched both with and without capillary pressure. The STONE 1 and WAGHYSTR keywords are used to create three-phase hysteresis (Eclipse ref. 2006.1). In the case without capillary pressure the matched relative permeability from the two-phase processes without Pc is used as input.

In the G2 period the production seems to increase in two steps, see figure 2. This behaviour could be caused by an initial period of double displacement. In the double displacement period gas is displacing oil which again is displacing water. At the end of the G2 period there is an increase in oil production which could be caused by conversion to direct displacement i.e. gas displacing oil directly. This behaviour seemed to be difficult to model perfectly in the case without capillary pressure, see grey line in figure 12.

The keyword SOMWAT is used to create different residual oil saturation values for different water saturation values (Eclipse ref. 2006.1). The problem in the case without capillary pressure is that the water saturation drops to a low value almost instantaneously after the gas injection is started. The water saturation value for the switch to a lower residual oil is difficult to isolate. The total oil production in the G2 period is not possible to achieve even when using a residual oil equal to zero in some parts of the SOMWAT table.

Another problem for the case without capillary pressure included is that the increase in oil production from the secondary gas injection is too late in time. The injection pressure, as seen in figure 12, is also a bit inaccurate.

When capillary pressure was included the oil production was lower, as expected. This case is seen as the black dashed line in figure 12. The relative permeability data had to be changed to obtain a match.

In the three-phase match with capillary pressure the relative permeability from the two-phase match with capillary pressure is used as input. In this case it is possible to match the behaviour seen in the G2 period, see black line in figure 12. This is because the water saturation decreases more slowly when capillary pressure is included.

The threshold water saturation value for the transformation to a lower residual oil is easy to identify. A lower value for the residual oil is used for the lower water saturations, which occur at the end of the G2 period. This time the minimum residual oil in the SOMWAT-table was the same as the measured value, i.e. 6%, see table 1. At the beginning of the G2 period the water saturation is high, and the chance of double displacement taking place is more likely. Consequently the residual oil in this early phase is likely to be higher.

Another improvement when including capillary pressure is that the timing of the increase in oil production from the secondary gas injection is more correct than for the case without capillary pressure.

The residual oil modification fraction in the WAGHYSTR keyword also had to be tuned to get a match of the W3 period. The fraction used in the match was 0.18.

The match of the injection pressures is very good; see black line in figure 13. It is much better matched than for the case without capillary pressure, seen as the grey line in figure 13.

Killough's three-phase capillary pressure correlation as input to three-phase flow

A case with Killough's (1976) three-phase capillary pressure correlation was also tested. The three-phase capillary pressure was unknown and therefore the default values were used in the Killough correlation. When using Killough's capillary pressure correlation the oil recovery was even lower, see figure 14. The grey line is the case without capillary pressure, the dashed black line is the case with two-phase capillary pressure, and the case with Killough's correlation is shown as the solid black line.

The case with Killough's capillary pressure was history matched to the experimental data. The table of residual oil versus water saturation had to be adjusted when history matching the G2 period. The drop in the water saturation was slower for the case with Killough's three-phase capillary pressure than when using the two-phase capillary pressure. The minimum residual oil saturation was 6% also in this case. The water saturation value, when this residual oil saturation was reached, was higher than for the case with two-phase capillary pressure.

The match of the W3 period was obtained by changing the fraction of trapped gas reducing the residual oil. The fraction had to be increased from 0.18, as used in the history match with two-phase capillary pressure, to 0.25. The G4 period did not have any oil production in the experiment. Oil was however produced during the simulated G4-injection with Killough's three-phase capillary pressure. Figure 15 shows the case without capillary pressure as the grey line and with Killough's capillary pressure as the black dashed line. The history match with Killough's three-phase capillary pressure is shown as the solid black line.

The differential pressure was better matched in the case with capillary pressure included, when compared to the cases without capillary pressure, except for the W3 period. The grey line in figure 16 is for the case without capillary pressure and the black line is for the case with capillary pressure.

Comparison between using Killough's three-phase capillary pressure correlation and two-phase capillary pressure

The history match of the WAG-process was quite good for both the case with two-phase capillary pressure and Killough's capillary pressure as input for three-phase flow. The match of the G4 injection period was better for the case with two-phase capillary pressure as input for three-phase flow. The match of the differential pressure was also a bit better for the case with two-phase capillary pressure. The history match with two-phase pressure for three-phase flow is seen as the grey line in figures 17 and 18. The match with Killough's capillary pressure correlation for three-phase flow is shown as the black line in figures 17 and 18.

4.4 Discussion

The results from this work are that capillary pressure has a significant effect on flow in porous media for both two- and three-phase flow. The relative permeability of oil had to be increased and the relative permeability of the injected fluids had to be decreased when capillary pressure was included. The relative permeability for both the case with capillary pressure and without capillary pressure was obtained by an inverse method. The relative permeabilities were found from history matching of core floods with and without capillary pressure.

Other authors have quantified the effect of capillary pressure by comparing relative permeability from analytical models neglecting capillary pressure with relative permeabilities from history matching with capillary pressure. Thus these results are not directly comparable to the work in this paper.

Skauge et. al (1999) compared relative permeabilities from analytical calculation, which neglected capillary pressure, with history matched relative permeabilities with capillary pressure included. They found that a G1W2-process was strongly influenced by capillary pressure. Both the production and the pressure profiles were affected by the capillary pressure. This is the same result as seen from this work. Only a minor effect of capillary pressure was seen for an injection sequence with short slugs of gas and water in the work by Skauge et. al.

Element and Goodyear (2002) stated that analytical methods for calculation of relative permeability, like the JBN-method, will underestimate the oil recovery. This is because these analytical methods neglect capillary pressure. They analyzed a two-phase water injection case. The simulated fractional flow curve was compared to a curve calculated by the JBN-method which neglects capillary pressure. The simulated fractional flow curve showed higher mobility for the oil when including the effect of capillary pressure. This is in agreement with our results, where the oil relative permeability is higher when capillary pressure is included.

From this work the effect of capillary pressure on flow seems to be significant. The capillary pressure is important when history matching production data. If capillary pressure is neglected, the relative permeability of oil will be underestimated and relative permeability of the injected fluids, gas and water, will be overestimated.

Another argument for including capillary pressure is that when doing so, it is possible to obtain a history match which is closer to the experimental data. When neglecting capillary pressure, the front between the injected fluid and oil becomes too sharp. Capillary pressure leads to dispersion of the front and the total oil recovery curve gets a shape which is closer to the experimental data. The pressure in the injector also seems to be better matched when including capillary pressure.

The nature of three-phase capillary pressure has not been well described. Only a few experimental measurements of three-phase capillary pressure exists (Kalaydjian, 1992). The only correlation for three-phase capillary pressure included in the simulator is Killough's (1976) correlation. An important issue is whether this correlation gives a better result than using two-phase capillary pressure for three-phase flow. The results from the current study indicated that using two-phase capillary pressure gives a better match of the oil recovery and the pressure in the injector than when applying Killough's correlation.

5 Conclusions

- When including capillary pressure the total oil production is significantly lower, and therefore
- the relative permeability of oil must be increased and/or the relative permeability of the injected fluid must be reduced to get a match,
- the shape of the total oil production curve is in most cases better matched when capillary pressure is included, and
- the match of the pressure in the injector is in most cases better when the capillary pressure is included.
- A better match was obtained when using two-phase capillary pressure curves for three-phase flow than when using Killough's three-phase capillary pressure correlation.

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Table 1: Summary of experimental data

Experiment	Swi	Floodingrate	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

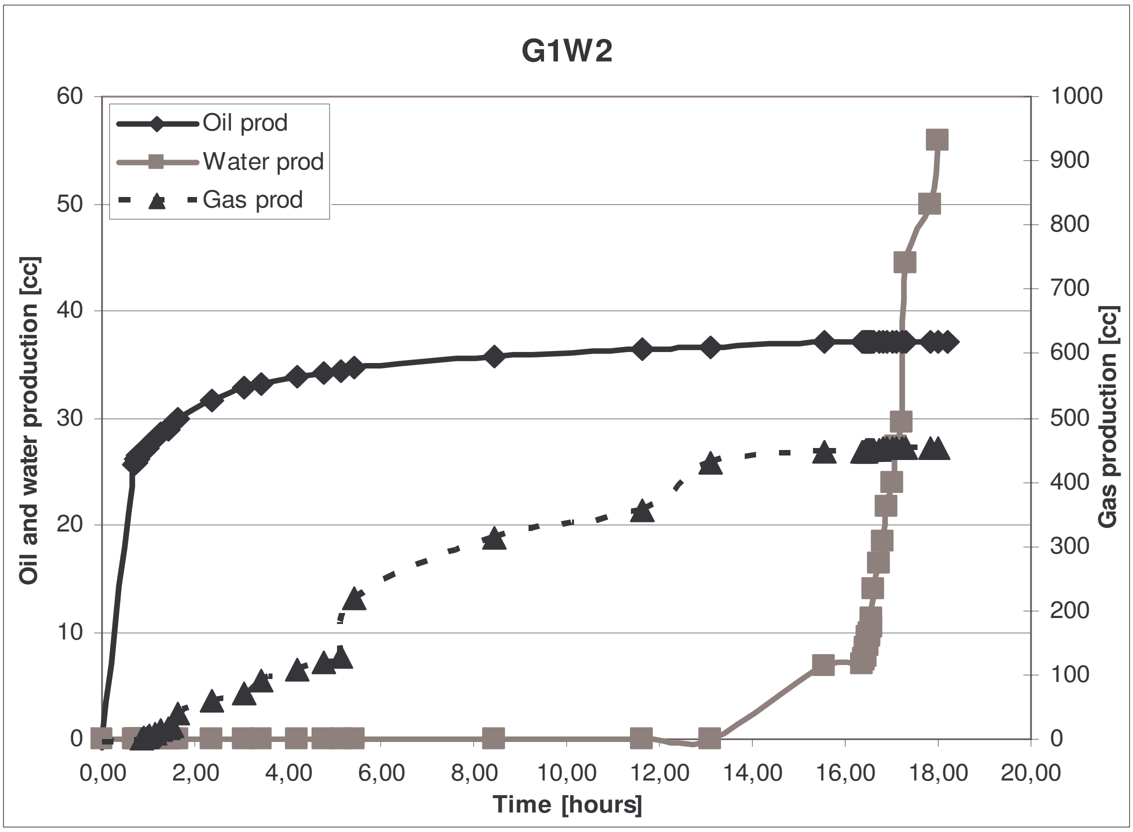

Fig. 1: Experimental data for G1W2.

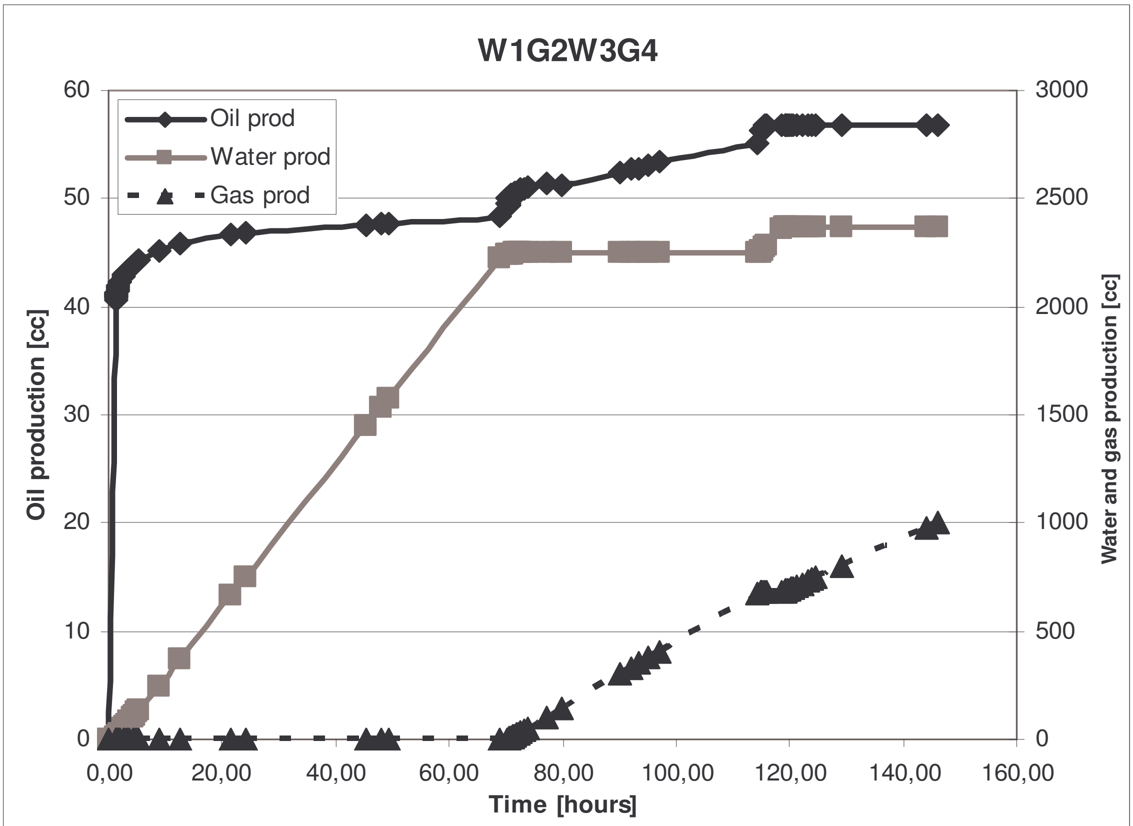

Fig. 2: Experimental data for W1G2W3G4.

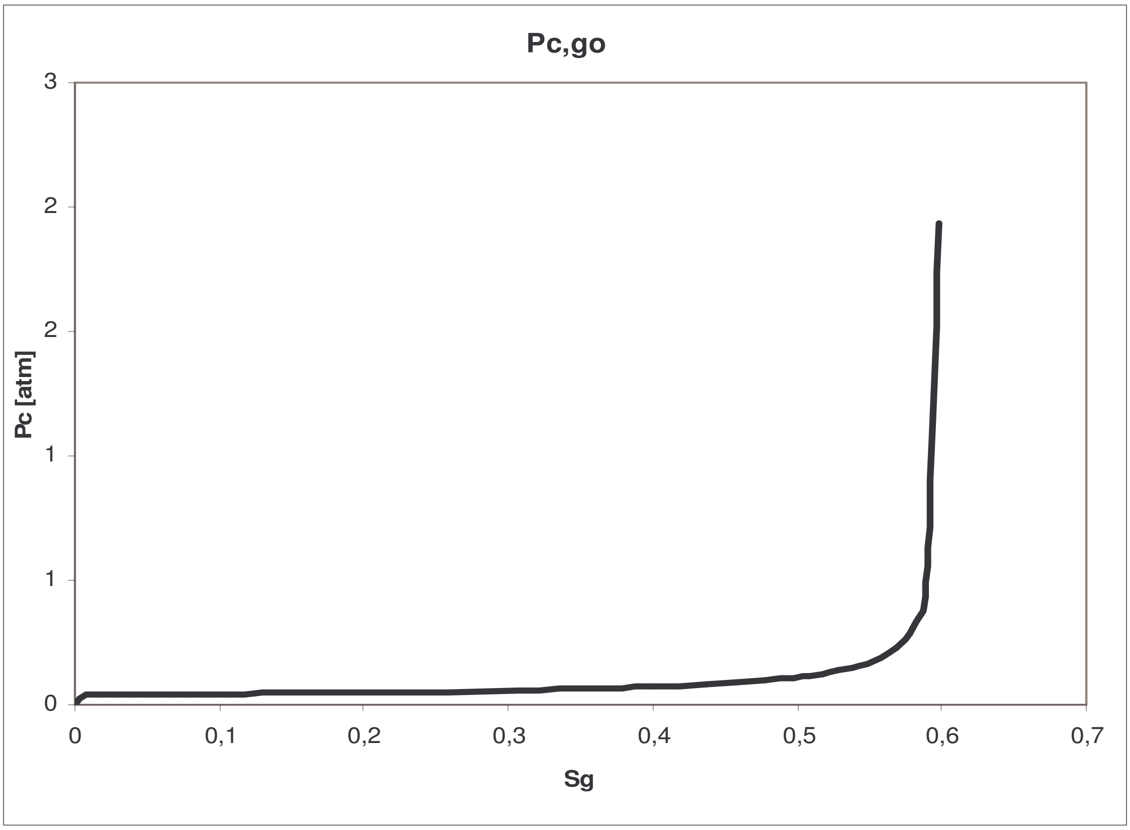

Fig. 3: Capillary pressure for the gas-oil process.

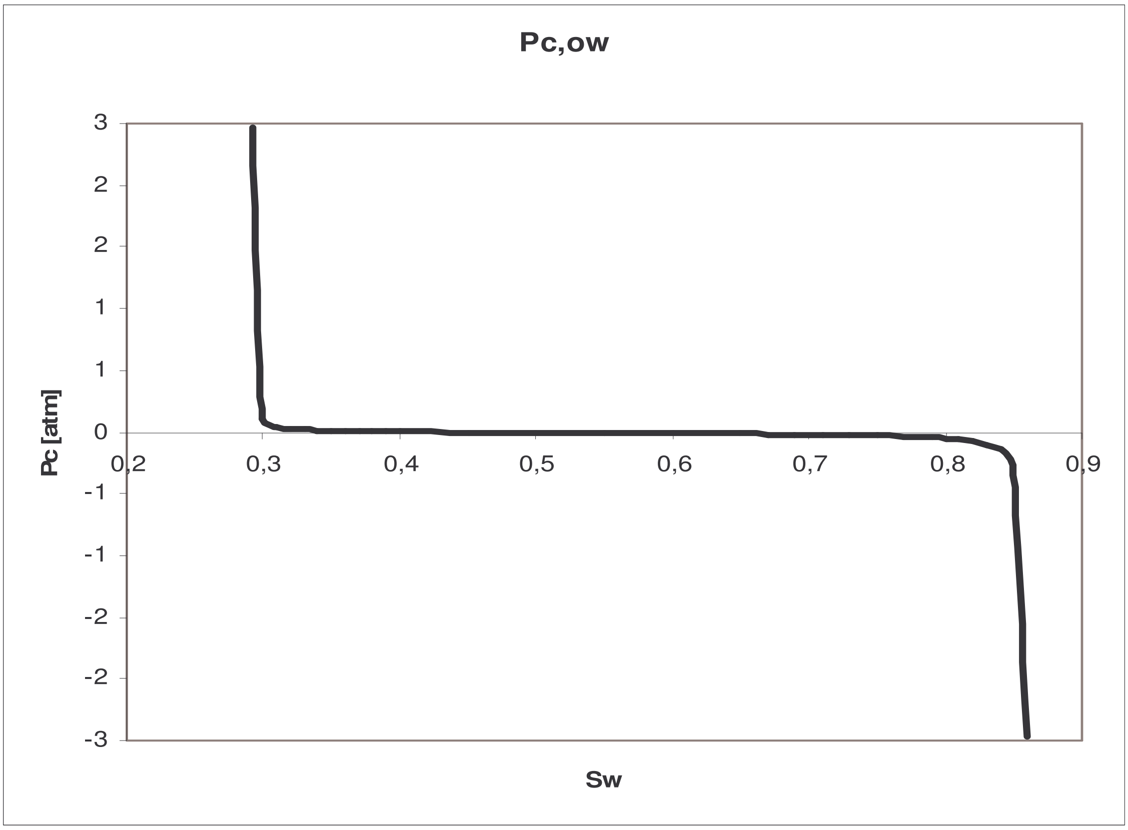

Fig. 4: Capillary pressure for the oil-water process.

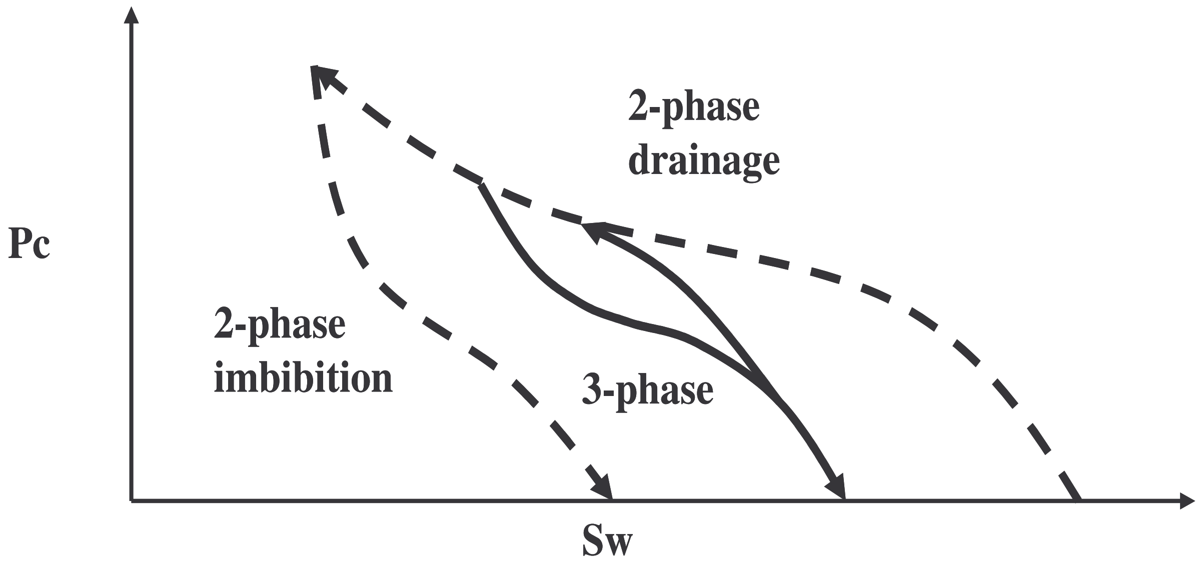

Fig. 5: Three-phase capillary pressure as a weighted average of the two-phase curves (Adapted from Eclipse technical description 2006.1).

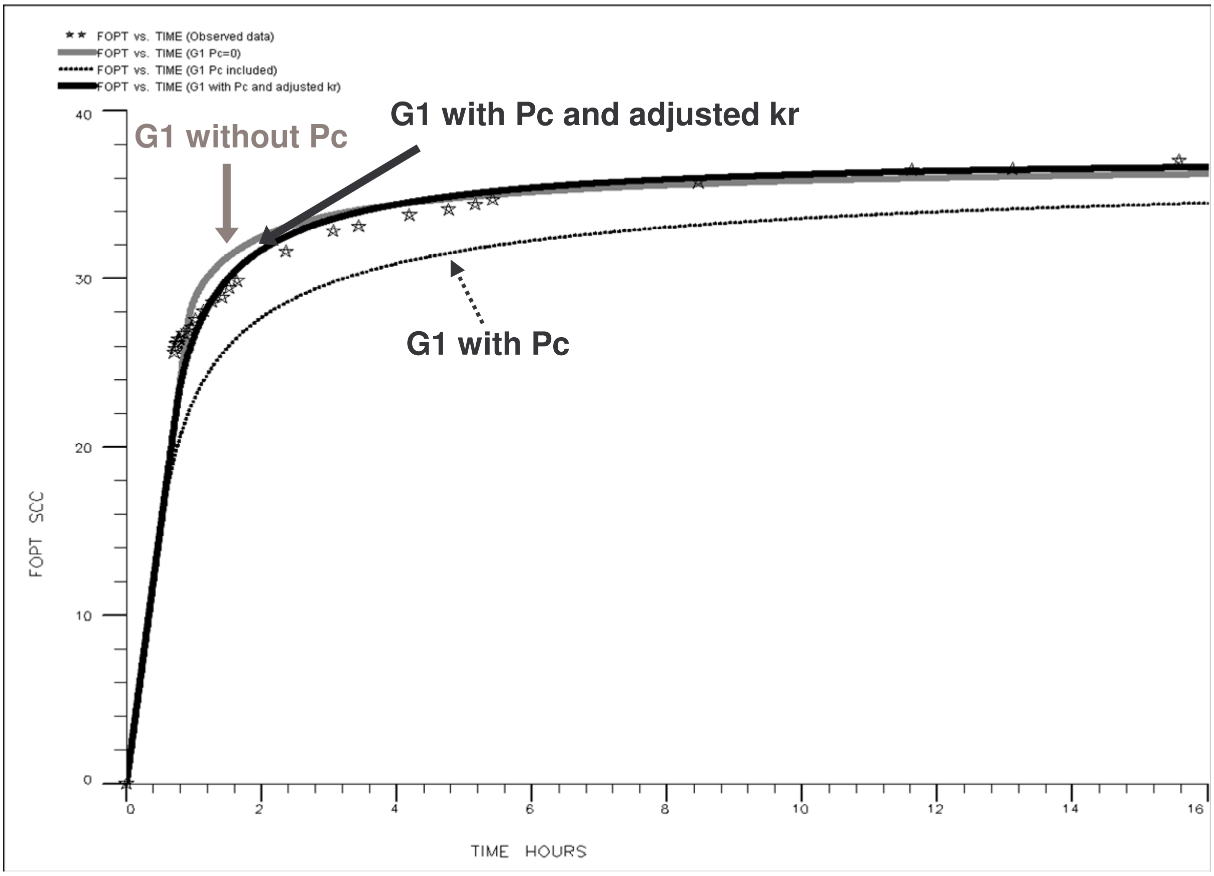

Fig. 6: Match of simulated total oil production with experimental oil production for G1.

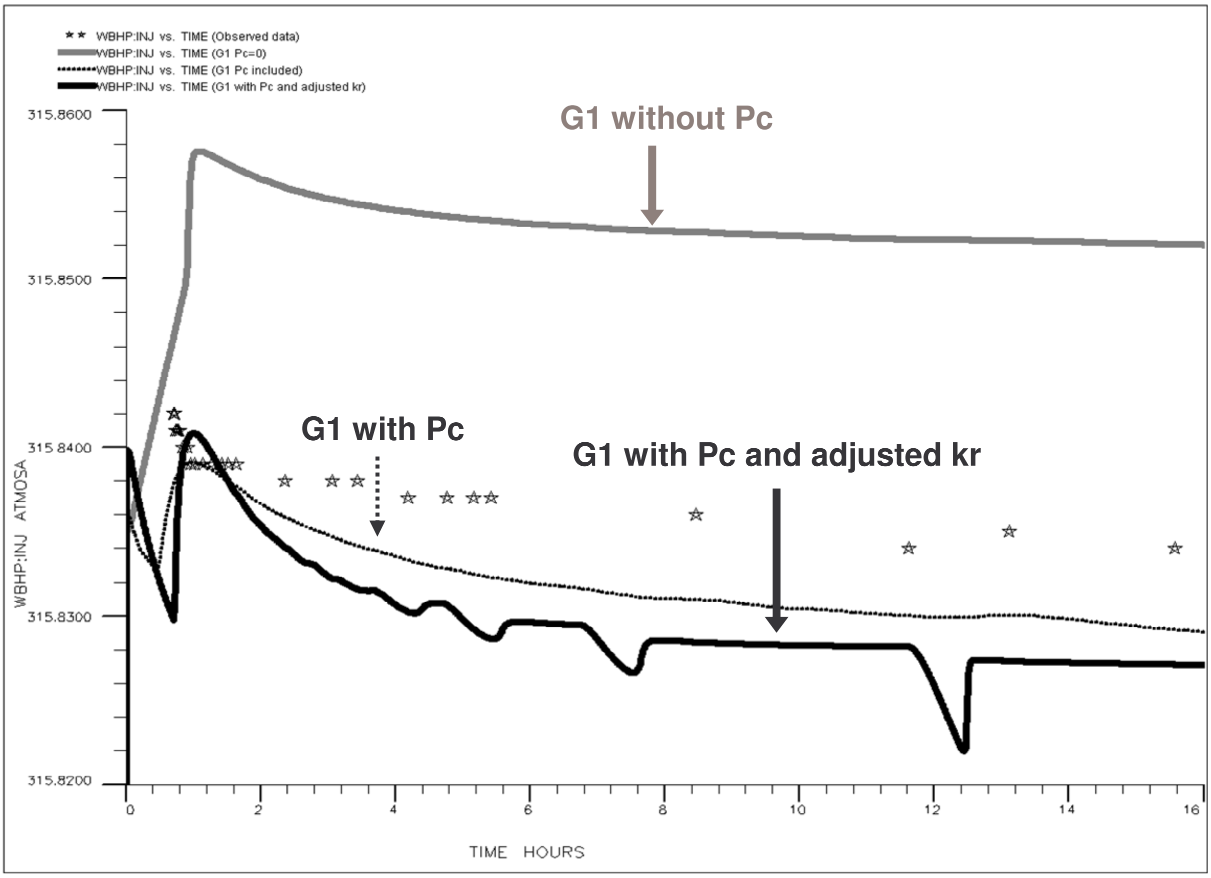

Fig. 7: Match of the injection pressure with experimental pressure for G1.

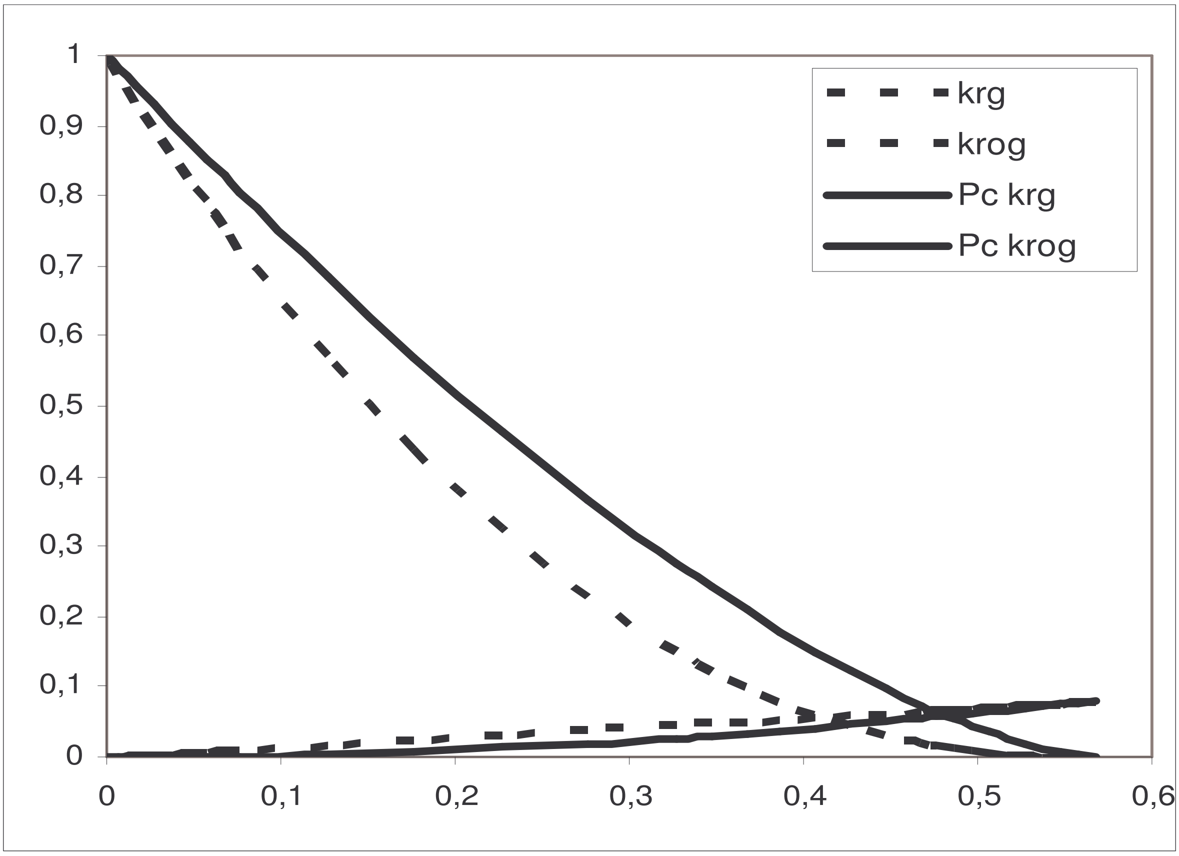

Fig. 8: Comparison of the relative permeabilities for match of the simulations with and without capillary pressure for G1.

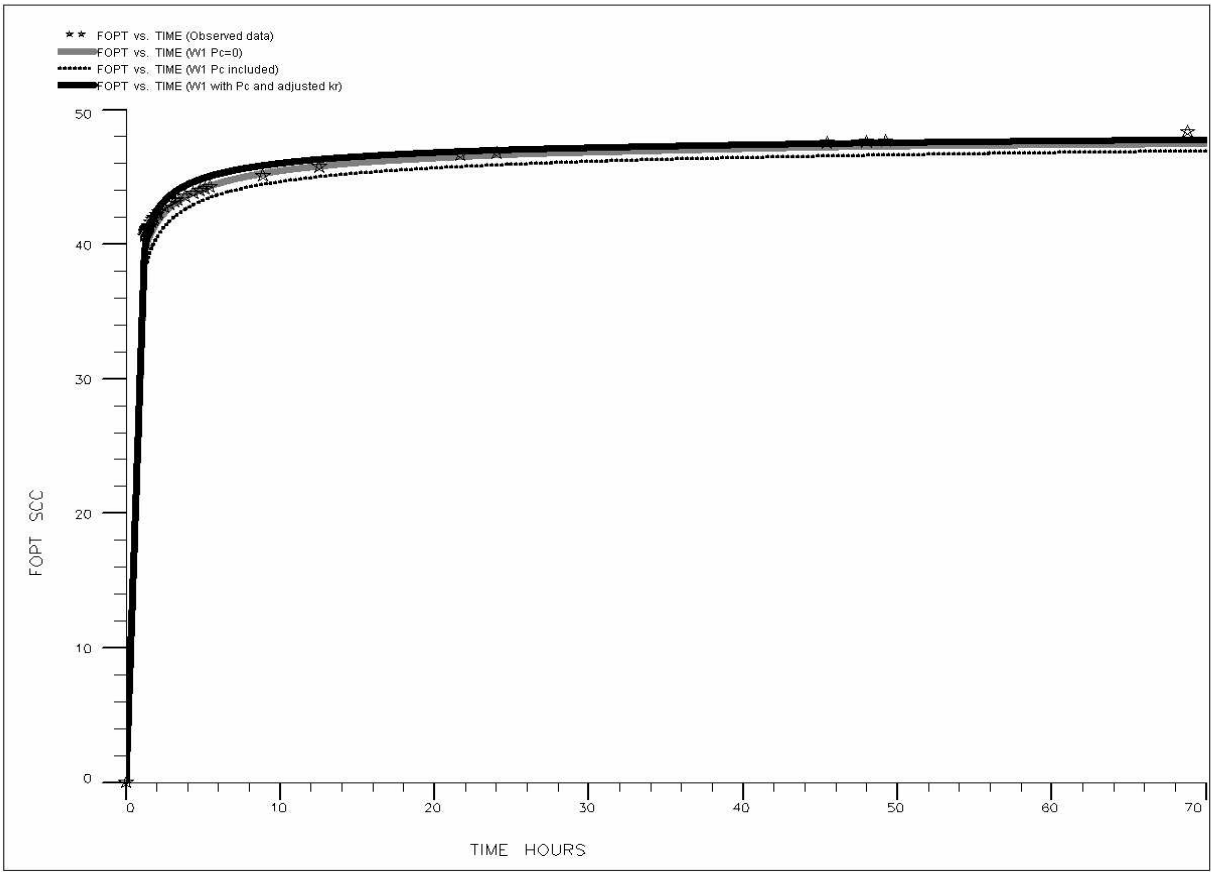

Fig. 9: Match of simulated total oil production with experimental oil production for W1.

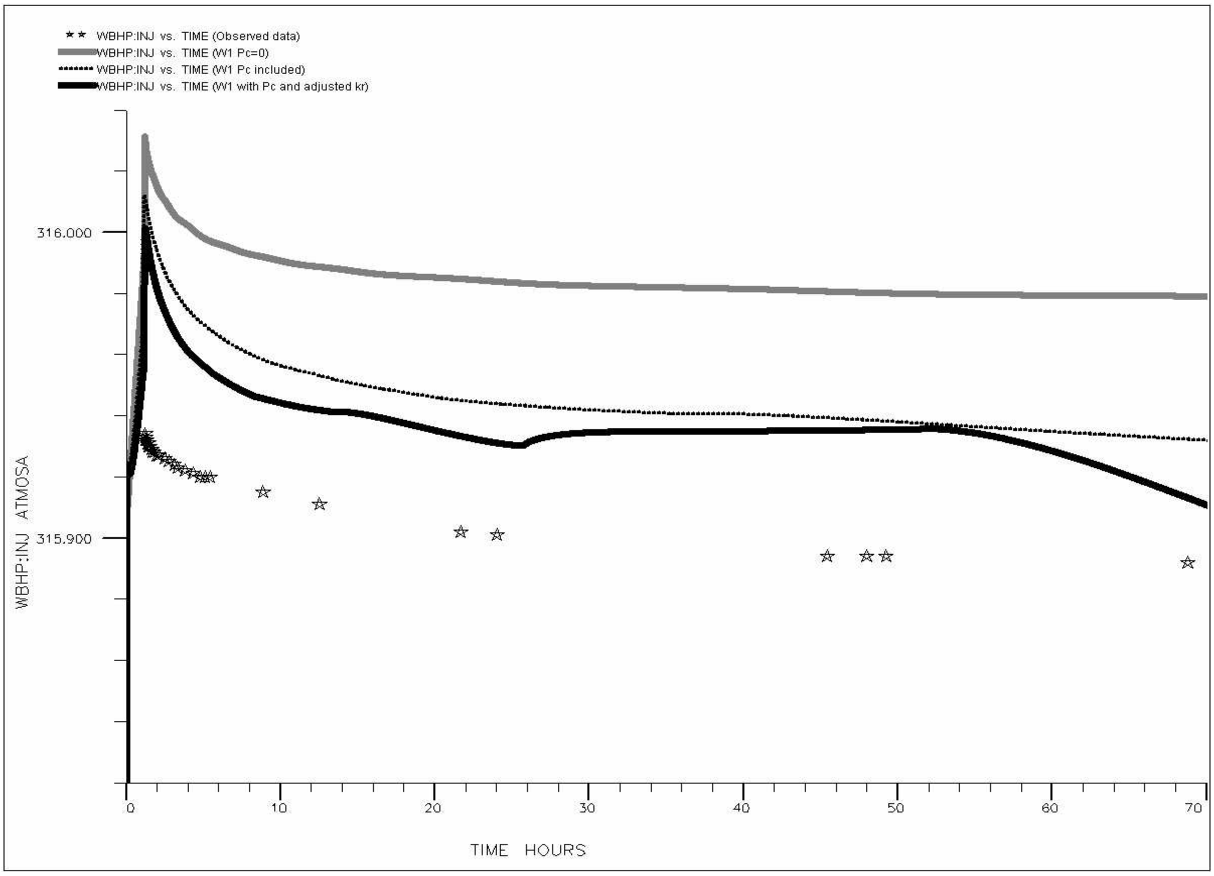

Fig. 10: Match of the injection pressure with experimental pressure for W1.

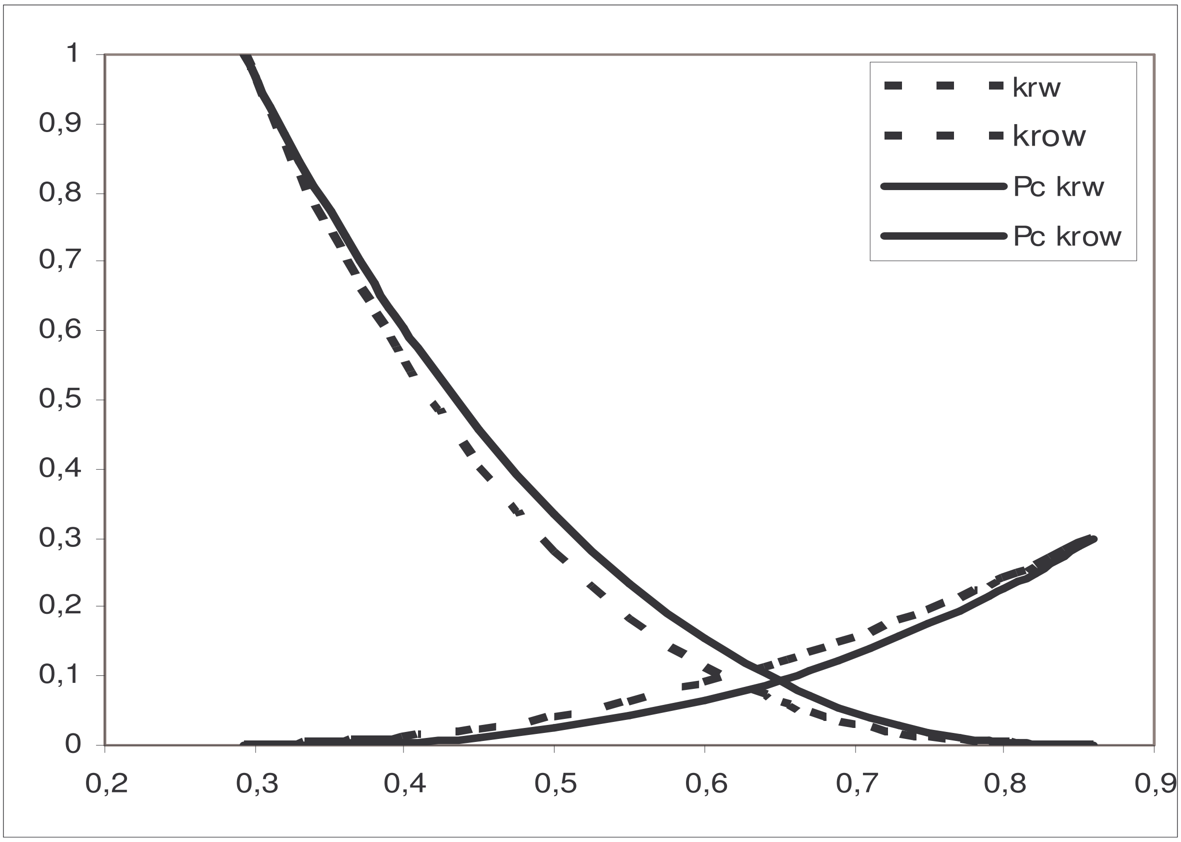

Fig. 11: Comparison of the relative permeabilities for match of the simulations with and without capillary pressure for W1.

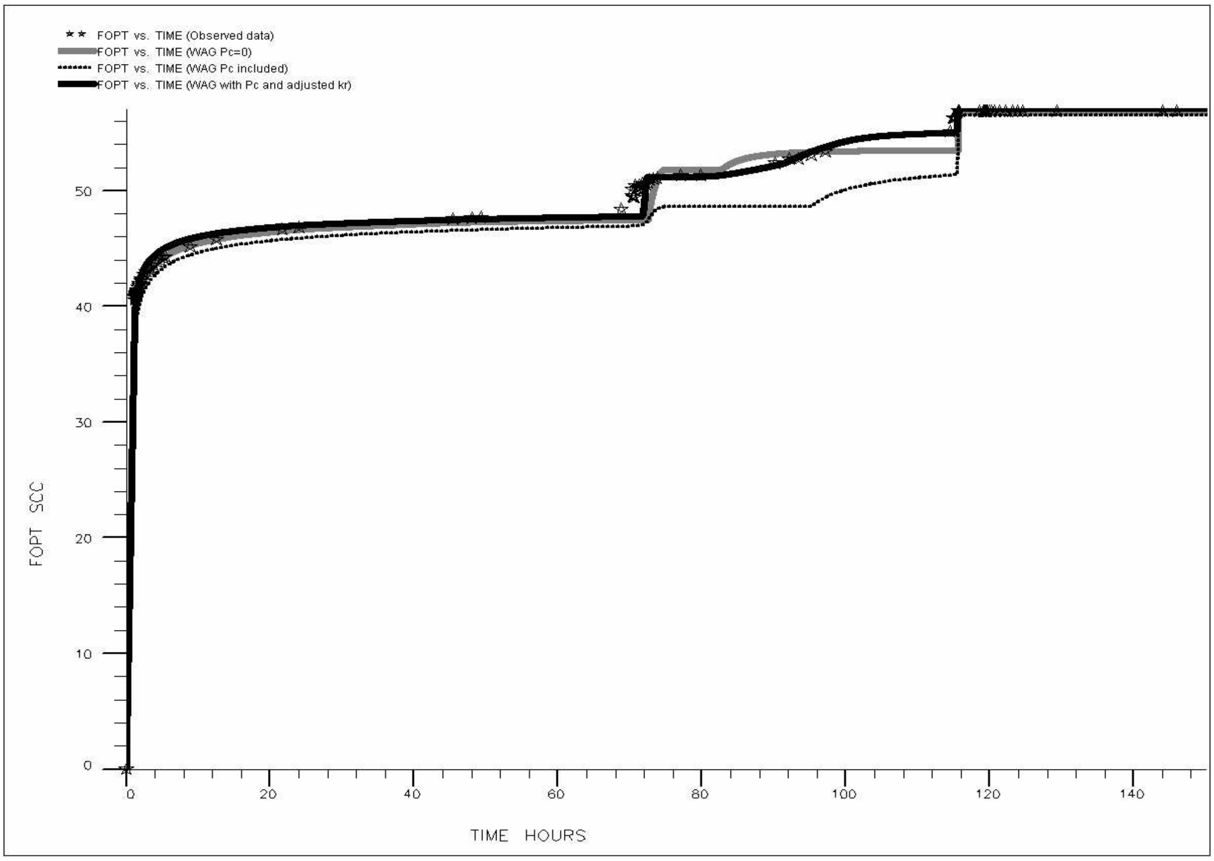

Fig. 12: Match of simulated total oil production with experimental oil production for WAG (W1G2W3G4) with two-phase Pc.

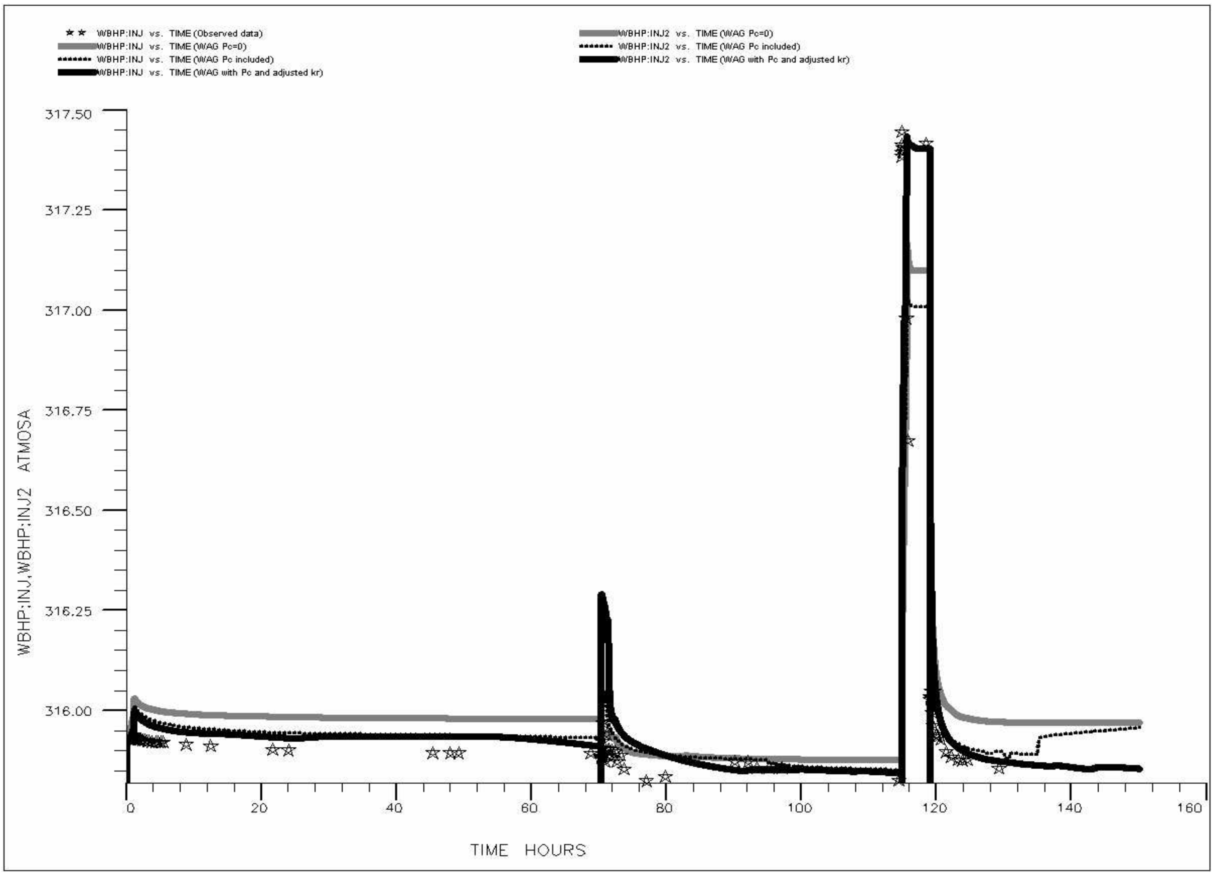

Fig. 13: Match of the injection pressure with experimental pressure for WAG (W1G2W3G4) with two-phase Pc.

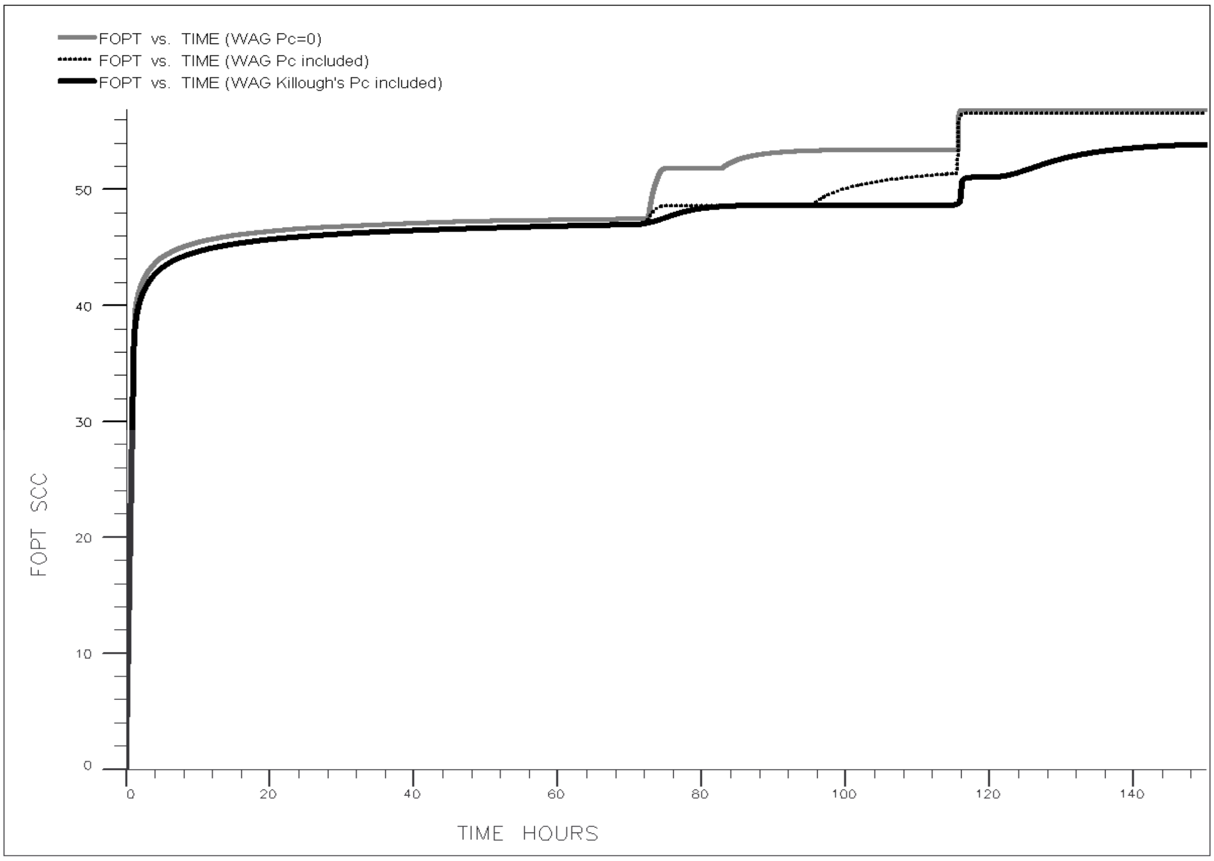

Fig. 14: Effect of Pc on total oil production with for WAG (W1G2W3G4) with two-phase Pc and Killough's Pc.

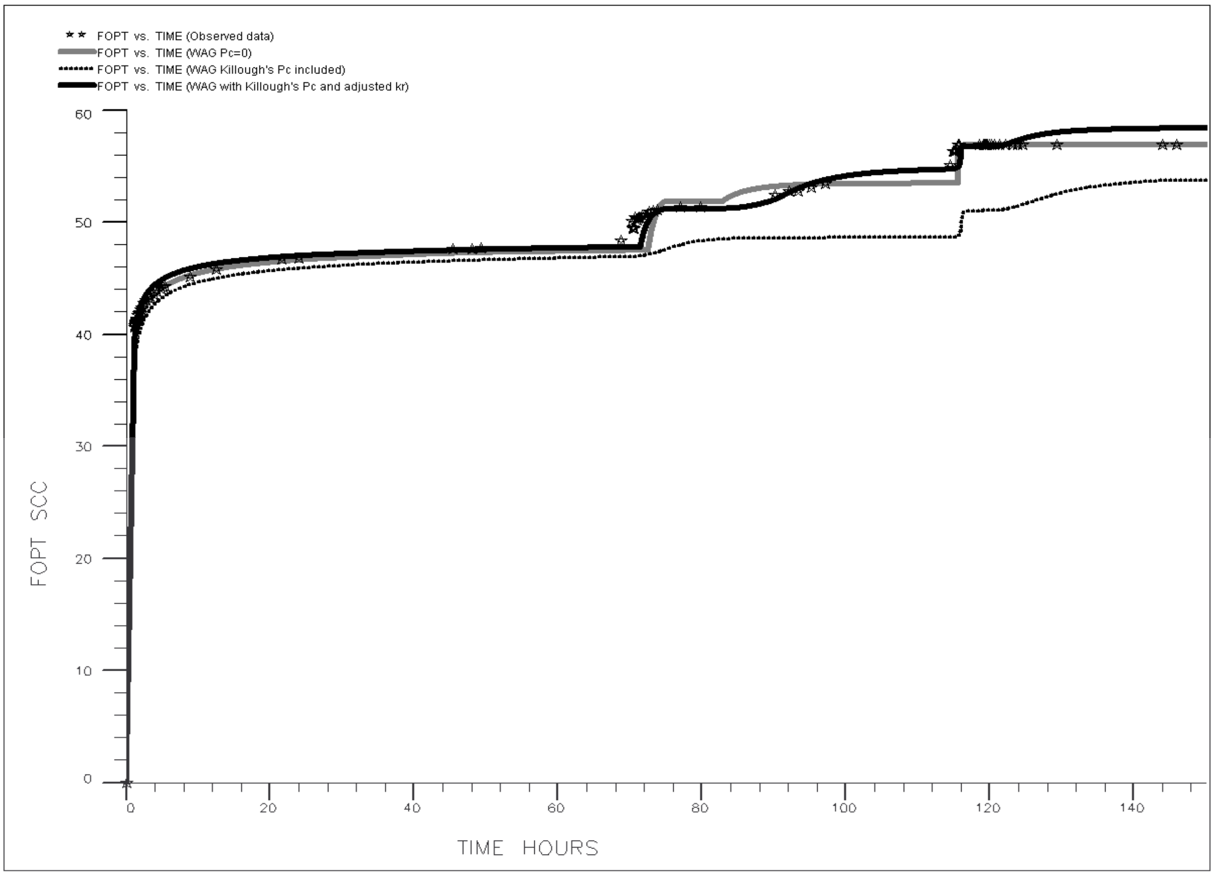

Fig. 15: Match of simulated total oil production with experimental oil production for WAG (W1G2W3G4) with Killough's Pc.

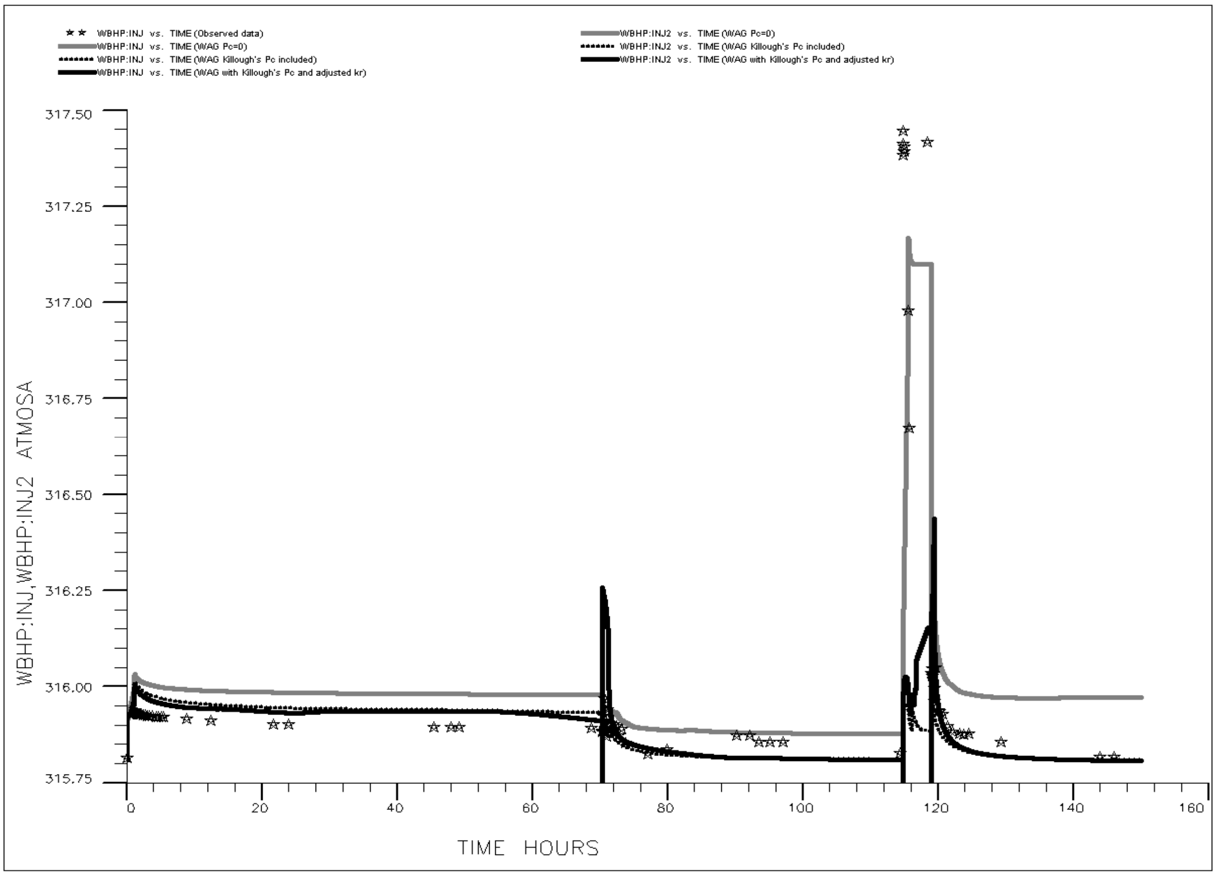

Fig. 16: Match of the injection pressure with experimental pressure for WAG (W1G2W3G4) with Killough's Pc.

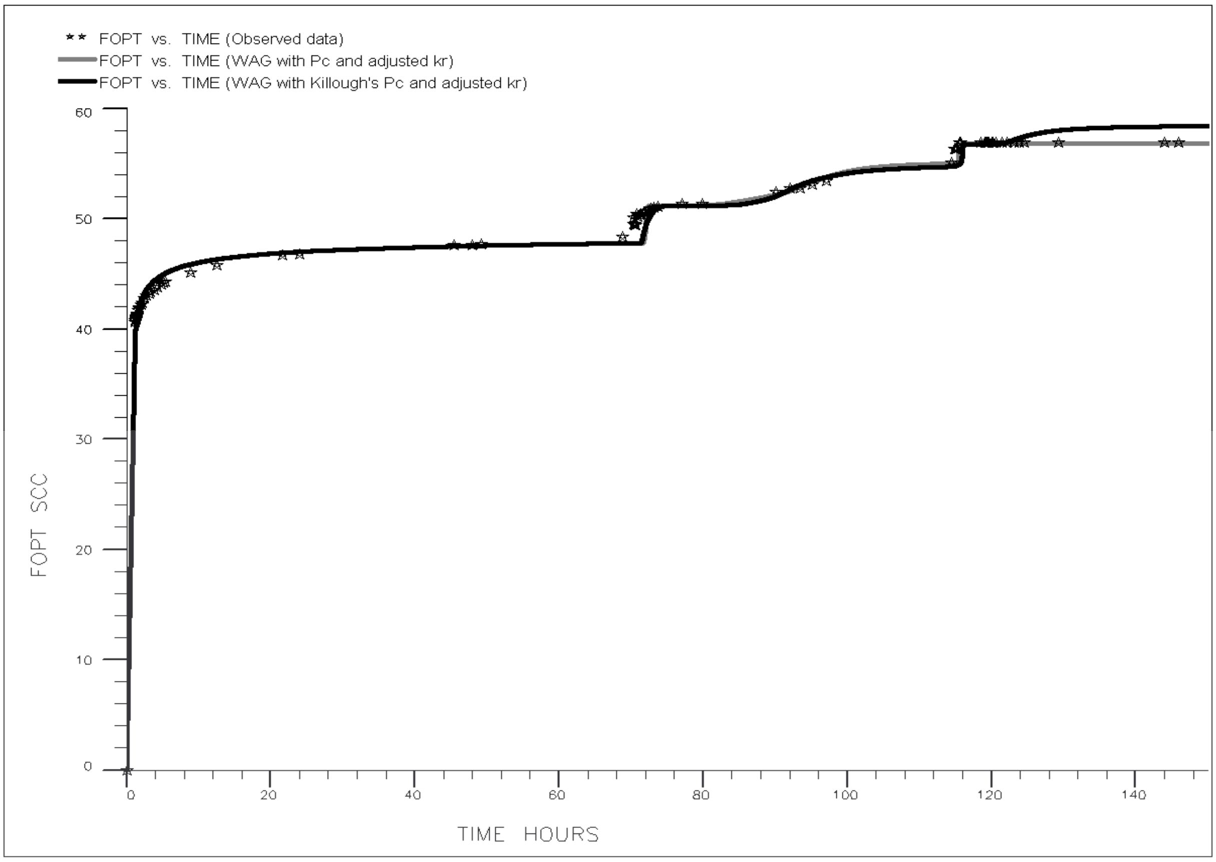

Fig. 17: Match of simulated total oil production with experimental oil production for WAG (W1G2W3G4) with two-phase Pc and Killough's Pc.

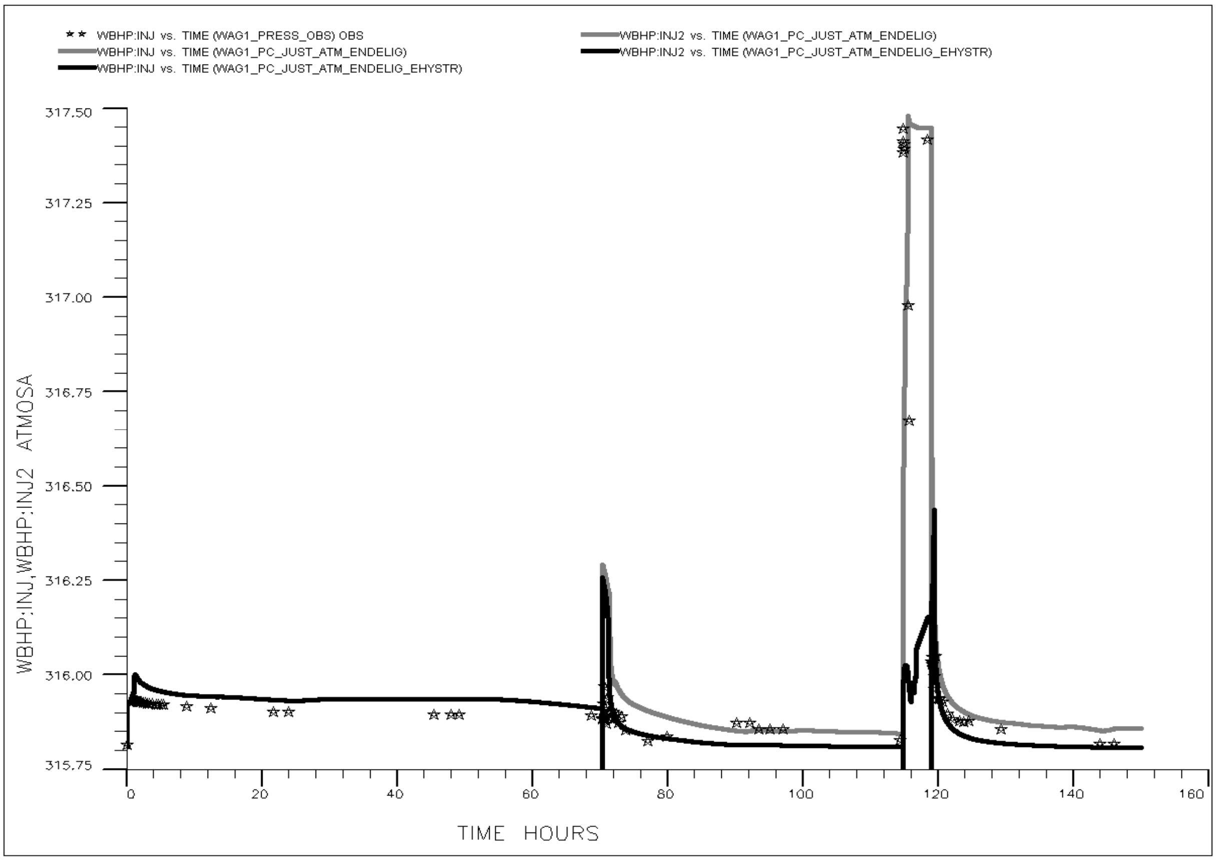

Fig. 18: Match of injection pressure with experimental pressure for WAG (W1G2W3G4) with two-phase Pc and Killough's Pc.