Effect of Implementing Three-Phase Flow Characteristics and Capillary Pressure in Simulation of Immiscible WAG

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Abstract

The effect of including a three-phase representation of the flow parameters and capillary pressure has been investigated using a black oil simulator. The simulation approaches include the complexity of three-phase flow, relative permeability hysteresis, dynamic phase trapping functions and capillary pressure. A WAG simulation case was used to study the effect of three-phase flow parameters and capillary pressure on the size of the three-phase zone, breakthrough time of the injected fluids and oil recovery.

Three-phase flow WAG processes are characterised by lower relative permeability of the injected fluids, because of flow path hysteresis and trapping of phases. It is important to incorporate these effects to have a correct description of the physics of multi-phase flow.

The results from this study showed that the size of the three-phase zone was considerably larger when a three-phase description of the flow was implemented. The reduced relative permeability of gas and water in the three-phase zone leads to slower segregation of gas and water. The breakthrough time of gas and water was delayed and the oil recovery was increased when hysteresis and trapping functions were included.

Including capillary pressure seems to further delay the breakthrough of the injected phases and the result is higher oil recovery. When including capillary pressure effects on the relative permeability, the three-phase zone was further extended and the oil recovery was increased.

These studies show the importance of using a more detailed fluid flow description in simulation of immiscible WAG processes.

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

Introduction

The size of the three-phase area has a large effect on the total oil recovery; because the residual oil is lower in the three-phase area.[1-4] It is well known that gas usually has better microscopic displacement efficiency than water. Areas flooded by both gas and water may however have even lower residual oil than after gas injection. The reduction in residual oil is often linked to the trapped gas saturation[3]

$$S_{orm} = S_{orw} - R \times S_{gt}, \tag{1}$$

where S_{orm} is the minimum residual oil saturation after three-phase flow, S_{orw} is the residual oil saturation after water injection, R is a reduction factor and S_{gt} is the trapped gas saturation.

The analytical methods for estimating the three-phase zone may strongly underestimate the size.[5-6] Stone[5] stated that the size of the three-phase zone depended on the injection rate, the vertical permeability and the density difference between the fluids. He proposed the equation

$$q_t = \Delta\rho\, k_v\, L_G\, W\left(\frac{k_{rw}}{\mu_w} + \frac{k_{rg}}{\mu_g}\right), \tag{2}$$

where q_t is the total injection rate, $\Delta\rho$ is the density difference between the fluids, k_v is the vertical permeability, L_G is the length the three-phase area extends from the injection well, W is the transverse distance between the injection wells, k_{rw} is the two-phase relative permeability of water, μ_w is the viscosity of water, k_{rg} is the two-phase relative permeability of gas and μ_g is the viscosity of gas. Such analytical models will underestimate the three-phase area because it does not take the effect of relative permeability hysteresis, three-phase relative permeability and capillary pressure into account.

Hysteresis of the relative permeability curves is common. The relative permeability curves are in many cases not reversible. One of the most important reasons for hysteresis is gas trapping. If a gas injection period is followed by water injection a significant part of the gas can be trapped. The amount of gas trapped is usually quantified by the Land constant[7]

$$C = \frac{1}{S_{gt}} - \frac{1}{S_{gi}}, \tag{3}$$

where S_{gt} is the trapped gas saturation and S_{gi} is the initial or maximum gas saturation. Two-phase hysteresis models like the Killough[8] and Carlson[9] models are based on Land's correlation. It is assumed that imbibition process is reversible. The drainage process leads to gas trapping which gives hysteresis.

It has been shown that the three-phase relative permeability is significantly different from the two-phase relative permeability. The relative permeabilities of the injected fluids, gas and water, is reduced in the three-phase zone.[10] A three-phase relative permeability model[11] was developed. This model has hysteresis for both the drainage and imbibition process and takes into account the reduced mobility of the injected fluids during three-phase flow.

Using correct representations of the relative permeability is important when estimating the extent of the three-phase zone. Reduced mobility of the injected fluids during three-phase flow leads to slower gravity segregation of gas and water. The size of the three-phase zone is larger when using correct representations of three-phase relative permeabilities and phase trapping. Simulation studies have shown large three-phase zones.[12-16]

Earlier work done by Dale and Skauge[17-18] demonstrated that capillary pressure had a significant effect on flow in porous media. History matching of a core flood experiment showed that the relative permeabilities of the injected fluids, gas and water, must be reduced when capillary pressure is included. The relative permeability of oil must be increased when capillary pressure is included.

This work tries to show the effect of including these flow features on field scale. The effect of the three-phase characteristics and capillary pressure on the size of the three-phase area, breakthrough time of the injected fluids and oil recovery was investigated.

Simulations

Conditions

The black-oil simulator Eclipse 100[19-20] was used in this work. A synthetic case on field scale was used to illustrate the principles.

The grid size was 1000m × 100m × 100m, with a grid block size of 10m × 10m× 10m. This corresponds to a total of 10 000 grid blocks, see figure 1. The reservoir had homogeneous properties. The porosity was 25%. The horizontal permeability was 500 mD and the vertical permeability was 50 mD. The oil-water contact was placed far below the reservoir and the gas-oil contact far above the reservoir. This ensured that the reservoir was in the oil zone. The model was initialized based on the endpoints of the relative permeability curves. The initial oil saturation was 71%, with a connate water saturation of 29%. The density of water is 1000 kg/m^3, for oil it is 671 kg/m^3 and for gas 0.67 kg/m^3. The pressure is 300 bars.

A WAG scenario was executed in the reservoir. The production criteria were chosen after evaluating some test cases. The injected fluid was changed between gas and water every six months. The total injection time was 5 years. The main WAG-effect was expected to be small after this time. The injection and production rate was 1000 Rm^3/d. This ensured voidage replacement in the reservoir. Rate control of the wells was chosen because then the reservoir sees the same volume and the results are more comparable. The pressure in the injector will then fluctuate but it is assumed that this will be managed, for example by fracturing of the injector. The injector was placed 100m from the end of the reservoir and the producer 100m from the other end, see figure 1.

Simulation cases

Five cases were compared.

Two-phase relative permeability: Case 1 was WAG using a two-phase representation of relative permeability with no hysteresis. In case 2 capillary pressure was included but all other parameters were kept the same. When history matching the relative permeability curves would have to be changed when including capillary pressure[17-18], but in this case we want to investigate the effect of capillary pressure at constant relative permeability. The correction of the relative permeability because of capillary pressure effects is taken into account in case 5.

Three-phase relative permeability hysteresis and gas trapping: Case 3 was WAG including three-phase relative permeability and gas trapping. The Stone 1 method was used to estimate the three-phase relative permeability of oil. The WAG hysteresis option[19-20] was included and the relative permeability of water and gas was reduced for the three-phase flow. Lower residual oil for three-phase flow was applied. In case 4 capillary pressure was included together with the three-phase features. Earlier work had indicated an effect of capillary pressure on the relative permeability representation.[17-18] The observed effect of capillary pressure, i.e. lower relative permeability of the injected fluids and higher relative permeability of oil, was included in case 5.

The capillary pressures and relative permeability curves used are representative for a North Sea type reservoir. The capillary pressure for gas-oil and oil-water can be seen in figures 2 and 3, respectively. The relative permeabilities used as input for three-phase flow for all the cases can be seen in figures 4 and 5. The oil relative permeability, seen in figures 4 and 5, are higher for three-phase flow, case 3 and 4, than for two-phase flow, case 1 and 2, and even higher when the effect of relative permeability is taken into account, case 5. The relative permeability of water is highest for two-phase flow, case 1 and 2, lower for three-phase flow, case 3 and 4, and even lower when the effect of capillary pressure on relative permeability is included, case 5. The input gas relative permeability is the same for two-phase and three-phase, cases 1, 2, 3 and 4. The three-phase gas relative permeability is however lowered by the WAG-hysteresis option in the simulator.[14-15] The input gas relative permeability is reduced when including the effect of capillary pressure on relative permeability, case 5.

The relative permeability input in case 1 and 2 is used directly, but the relative permeability input for the cases 3, 4 and 5 is modified by the three-phase hysteresis option in the simulator. This model incorporates hysteresis for both the wetting and the non-wetting phase. The Stone I model is used together with trapped gas reduction of residual oil. This produces process dependent oil relative permeability curves. The reduction of the relative permeability of the injected fluids during three-phase flow is also described by the model.

Results and discussion

To quantify the effect of correct relative permeability representations and inclusion of capillary pressure we have chosen some parameters to investigate. We have chosen to focus on the size of the three-phase zone, breakthrough of the injected fluids and oil recovery.

Size of the three-phase zone

The criteria for defining a grid block as part of the three-phase flow zone was that it had both mobile gas and mobile water present. The threshold for the gas saturation was set to minimum 1%, and the water saturation had to be above the irreducible saturation, i.e. minimum 30%. The three-phase zone when using two-phase representations of the relative permeability can be seen in figure 6. The three-phase zone is largest at the top of the reservoir. The water seems to segregate slower than gas for these conditions. When including capillary pressure, case 2, the three-phase zone was larger than without capillary pressure, case 1. The capillary pressure seems to delay the segregation of gas and water. The three-phase zone is primarily stretched out in the horizontal plane. The increase in the size was about 19 %. The three-phase zone for case 1 can be seen in figure 6 and the three-phase zone for case 2 can be seen in figure 7.

The three-phase zone was considerably larger when using three-phase representations of the relative permeability, case 3, when compared to two-phase representations, case 1. The increase in the size of the three-phase zone from case 1 to case 3 was 45 %. Reduced relative permeability of gas and water leads to slower segregation of both gas and water. The three-phase zone for case 3 is shown in figure 8. When including capillary pressure, case 4 shown in figure 9, the three-phase zone was larger than without capillary pressure. The difference in size from case 1 to case 4 was about 73 %.

The effect of capillary pressure on estimation of relative permeability was investigated in an earlier study.[17-18] The effect was reduced relative permeability of the injected fluids and increased relative permeability of the oil. When including this effect of capillary pressure on relative permeability the result was an even larger three-phase zone. The three-phase zone for case 5 was much larger than for the case with no three-phase characteristics included, case 1. The increase in size was about 103 %. The size of the three-phase zone was more than double the size in the base case, case 1. The three-phase zone in case 5 is shown in figure 10.

Breakthrough of the injected fluids and oil recovery

The relative permeability of the injected fluids is lower for the three-phase representation. Capillary pressure also seems to delay the segregation. The relative permeability of the injected fluids is even lower when the effect of capillary pressure on relative permeability is included. Low relative permeability of the injected fluids leads to slower gravity segregation.

Slower segregation of gas to the top and water to the bottom of the reservoir gives a larger three-phase zone and later breakthrough of the gas and water.

The breakthrough times for gas in all cases are shown in figure 11. Case 1 has the fastest segregation and the smallest three-phase zone and the earliest breakthrough time of the gas. Case 5 has the slowest segregation and the largest three-phase zone and the latest breakthrough time. The total gas production for the different cases can be seen in figure 12. The two-phase representation of the flow parameters, case 1, gives the highest gas production. The gas production decreases for each of the flow characteristics included, through cases 2 to 5.

The water production rate for all the cases can be seen in figure 13. The breakthrough time for the case with two-phase representations of the relative permeability, case 1, is earlier than for the case with capillary pressure included, case 2. When using three-phase relative permeability hysteresis and trapping, case 3, the breakthrough time is a little bit more delayed. When capillary pressure is used in addition to three-phase relative permeability hysteresis and trapping the breakthrough of water is even more delayed. For case 5 with lower relative permeability due to capillary pressure effects the water breakthrough is even later. The total water production for all the cases can be seen in figure 14. The water production decreases through cases 1 to 5.

The oil rate and oil recovery for the five cases is shown in figures 15 and 16, respectively. The residual oil is lower in the three-phase zone and therefore a large three-phase zone gives high recovery. Also late breakthrough of gas and water results in high recovery. The oil recovery is lowest for the case with the smallest three-phase zone and earliest breakthrough of the injected phases, case 1, and highest for the case with the largest three-phase zone and latest breakthrough, case 5. The increased oil recovery estimate is 35% higher for case 5 than for case 1.

Discussion

The three-phase zone is much bigger when three-phase hysteresis is included, case 3, than for the case with no hysteresis, case 1. This is consistent with the results in the paper by Skauge and Larsen.[12] The segregation of gas is greatly delayed both in this work and in the results from Skauge and Larsen. The increase in size found in this work was 45%. The size of the three-phase area was not quantified in the paper by Skauge and Larsen, but a visual inspection of the figures with gas and water saturation indicates an increase in the same order of magnitude.

The effect of capillary pressure in simulation of WAG on field scale has to our knowledge not been investigated earlier. The effect of capillary pressure was to further delay the segregation of gas and water. The increased size of the three-phase zone between case 2 with capillary pressure and case 1 with zero capillary pressure was 19%. The effect of capillary pressure on segregation was smaller than the effect of three-phase relative permeability hysteresis, but it is still a significant increase. The size is increased from 45% to 73% when including capillary pressure in the case with three-phase relative permeability hysteresis. This indicates that capillary pressure has a larger effect when used in combination with three-phase relative permeability hysteresis. The effect of capillary pressure on estimation of relative permeability was investigated in earlier work.17-18 Including this effect of increased oil relative permeability and decreased relative permeability of the injected fluids gives a further increase of the three-phase zone. Capillary pressure seems to have a considerable influence on the size of the three-phase zone.

The breakthrough time of gas was a bit delayed when three-phase relative permeability hysteresis was included; see the difference between case 3 and 1 in figure 11. This is consistent with earlier work, where three-phase relative permeability hysteresis was found to delay the gas breakthrough.[12, 14, 21-22] The total gas production showed a more significant difference, see figure 12. The three-phase hysteresis case, case 3, had lower gas production than the case without hysteresis, case 1.

The capillary pressure had only a minor effect on the gas breakthrough and gas production, see figures 11 and 12. When including the effect of capillary pressure on relative permeability, case 5, the effect was however more substantial, but the effect was smaller than the effect of relative permeability hysteresis.

The water breakthrough was delayed when using three-phase relative permeability hysteresis, see figure 13. The total water production was also smaller for the three-phase hysteresis case, see figure 14. This has not been reported in other papers.[14, 21-22] The gas breakthrough and production was however more affected in the other papers than in this work. It depends on the balance between the reduction of the gas and water relative permeability. In earlier work the reduction in gas relative permeability has been dominating, but in this work the effect is more even on the gas and water relative permeability reduction.

The capillary pressure had a small effect on the water breakthrough and the total water production. The water breakthrough was further delayed and the total production was smaller when capillary pressure was included. The effect of capillary pressure on relative permeability, case 5, had a large effect. The water breakthrough was considerably delayed and the total water production lower.

The three-phase relative permeability hysteresis had a large effect on the total oil recovery. The oil recovery was much higher when three-phase relative permeability hysteresis was included, see figure 16. This is consistent with most of the earlier work.[12-14, 22-23] Kossack[21] got higher total oil recovery for the case with no hysteresis, but these simulations were done on a one-dimensional grid. The positive effects of delayed segregation for three-phase relative permeability hysteresis will therefore not bee present.

Including the capillary pressure also had a small positive effect on the oil recovery. The case where the effect of capillary pressure on relative permeability is included show a significant increase in oil recovery.

When including all effects the increase in oil recovery is about 35%. This is a considerable increase in oil recovery. It shows the importance of including correct representations of relative permeability and capillary pressure when simulating WAG-injection.

Conclusions

Both three-phase relative permeability and capillary pressure delays the gravity segregation of gas and water and thus the three-phase zone is increased and breakthrough of the injected fluids is delayed.

When three-phase characteristics and capillary pressure are included breakthrough of gas and water is considerably delayed, which may lead to higher oil recovery.

The oil recovery is also increased because the residual oil is lower in the three-phase zone.

Comparing different fluid flow representations in simulation for an immiscible WAG process show that inclusion of all three-phase features and the effect of capillary pressure, gives the highest estimated oil recovery.

Ignoring the complexity of three phase flow in simulation of WAG leads to underestimation of the oil recovery.

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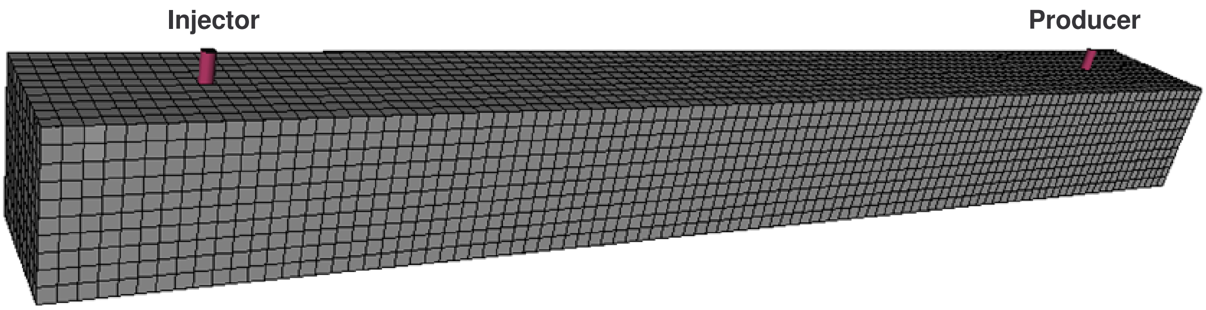

Fig. 1: Grid used in the simulations.

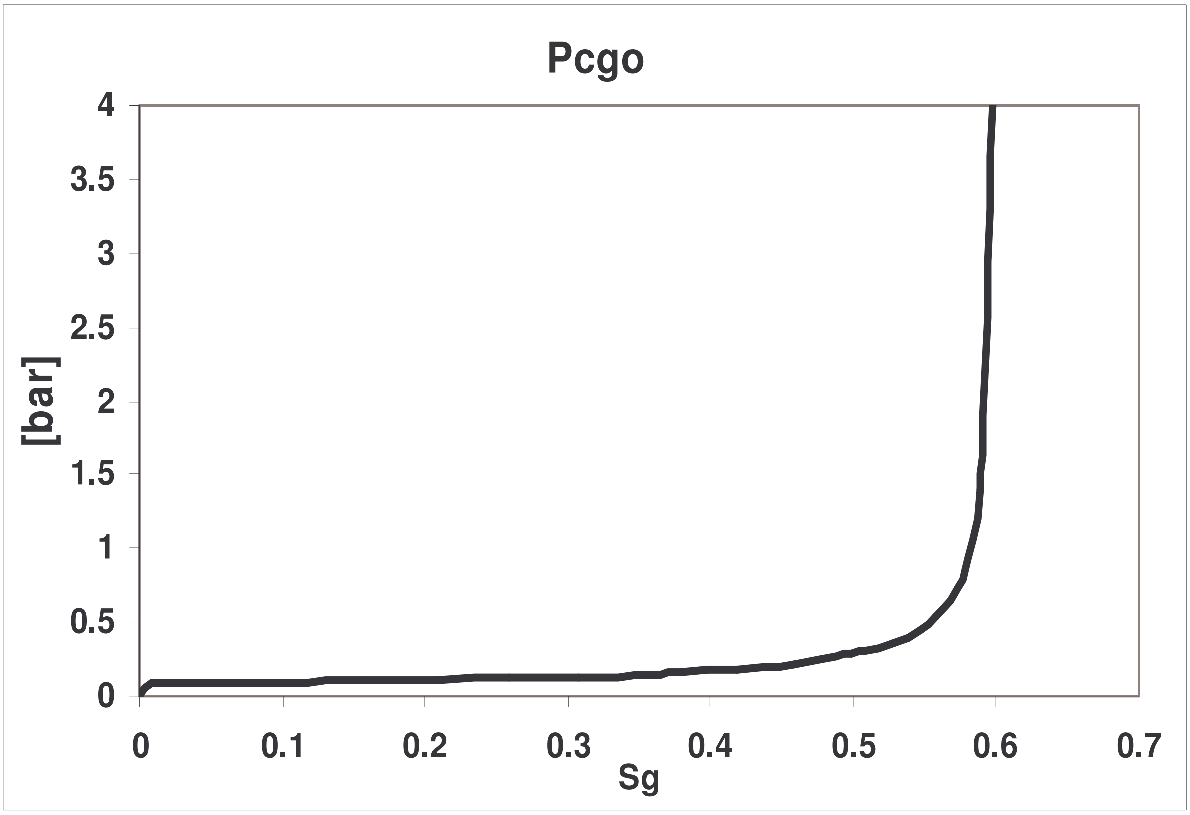

Fig. 2: Gas-oil capillary pressure.

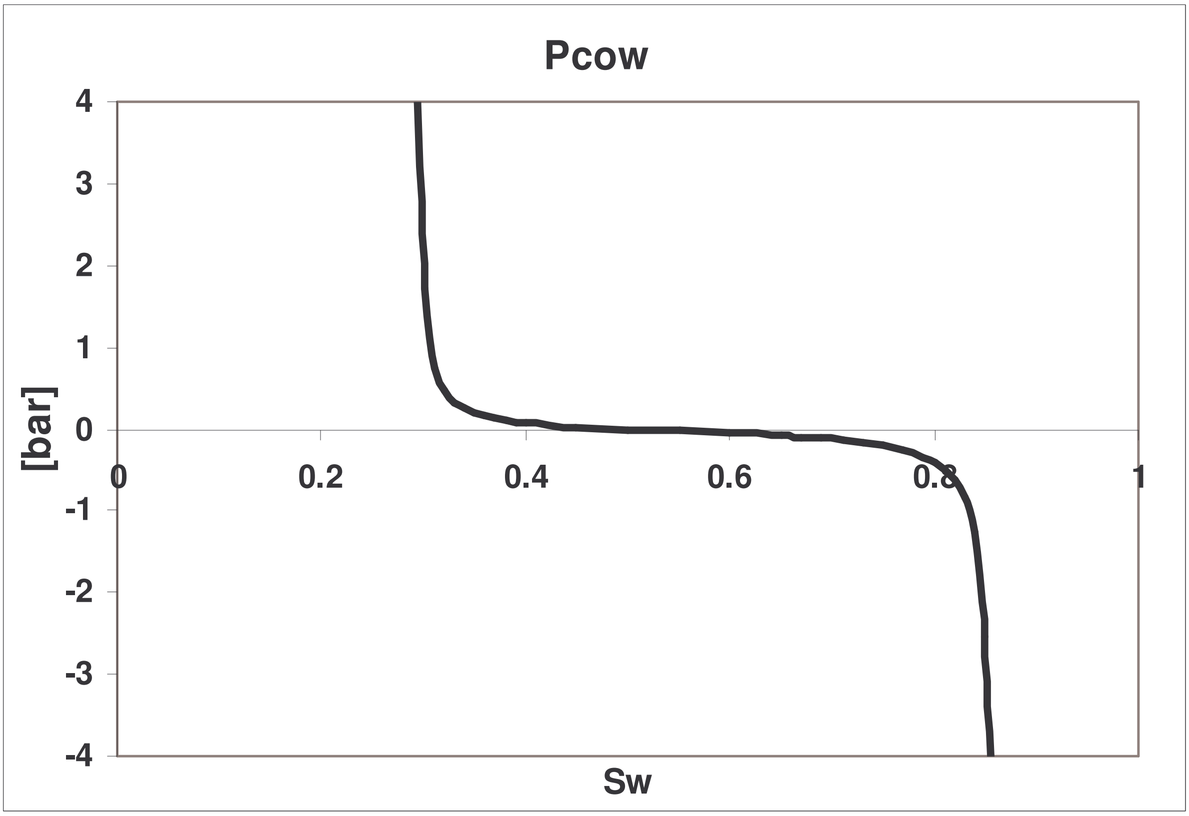

Fig. 3: Oil-water capillary pressure.

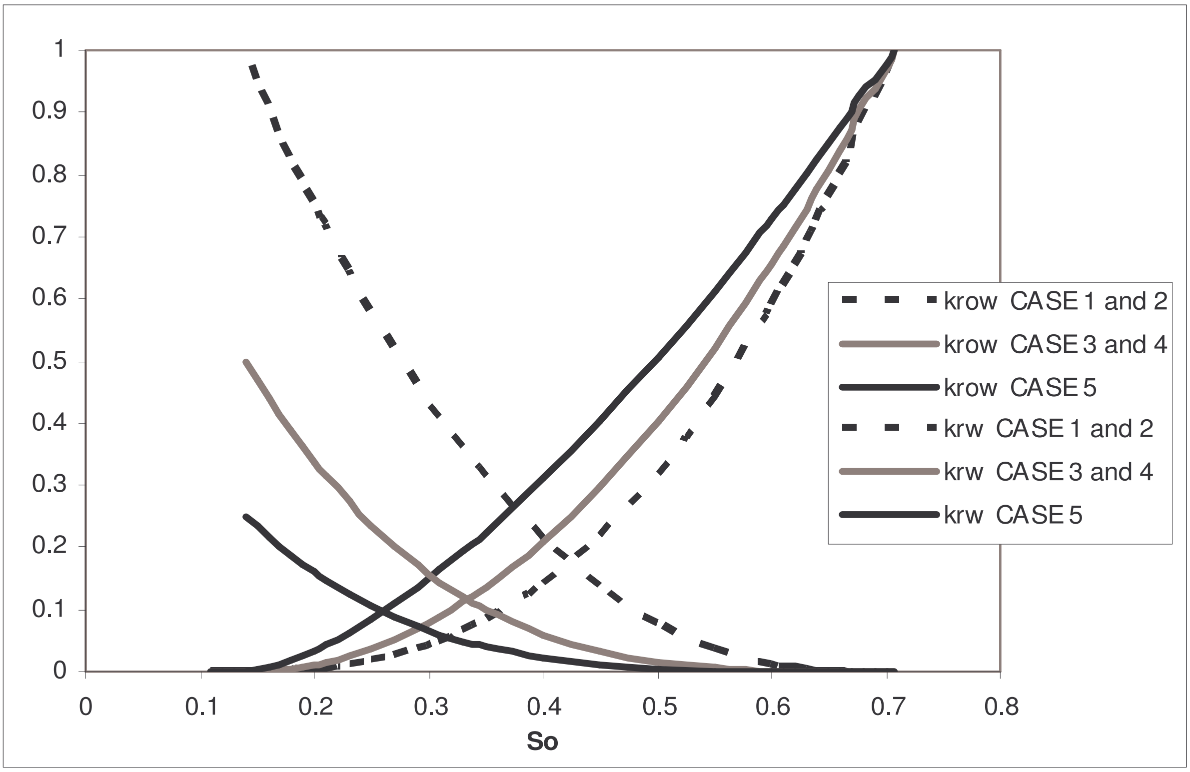

Fig. 4: Relative permeability of oil in presence of water, krow, and relative permeability of water, krw, for the different cases.

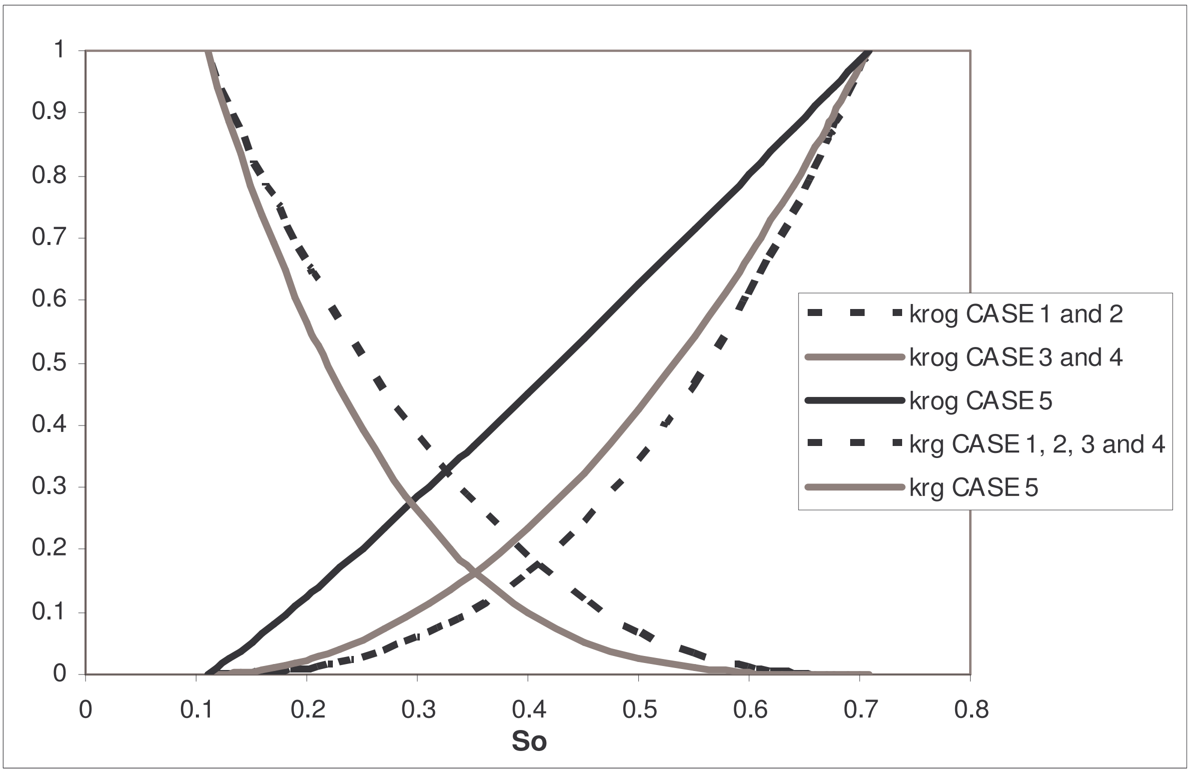

Fig. 5: Relative permeability of oil in presence of gas, krog, and relative permeability of gas, krg, for the different cases.

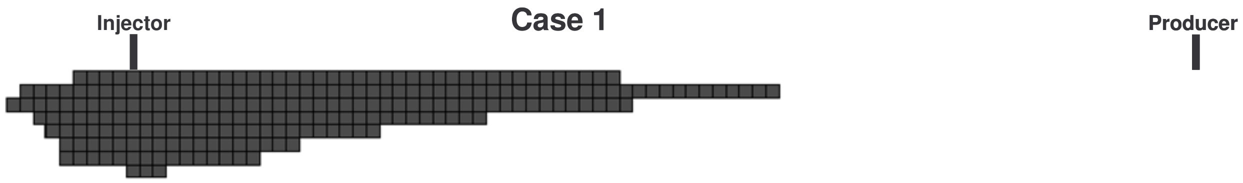

Fig. 6: Three-phase zone case 1: two-phase relative permeability.

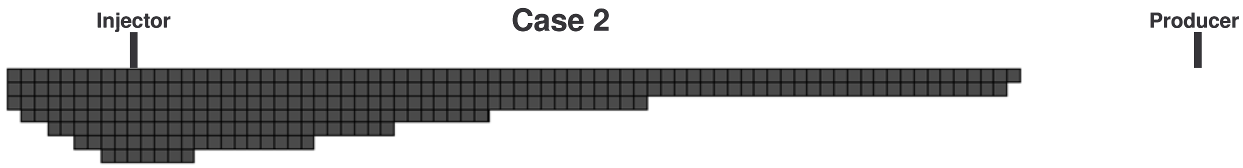

Fig. 7: Three-phase zone case 2: two-phase relative permeability including capillary pressure.

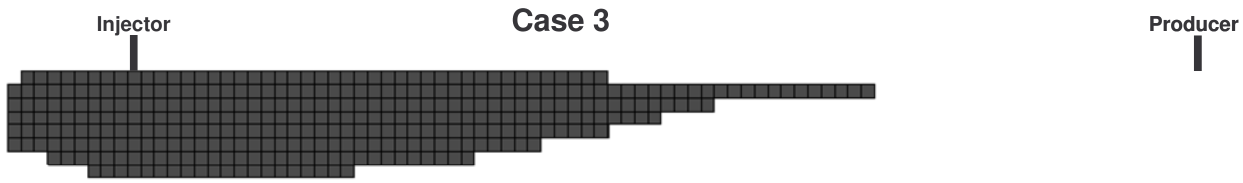

Fig. 8: Three-phase zone case 3: three-phase relative permeability hysteresis and trapping.

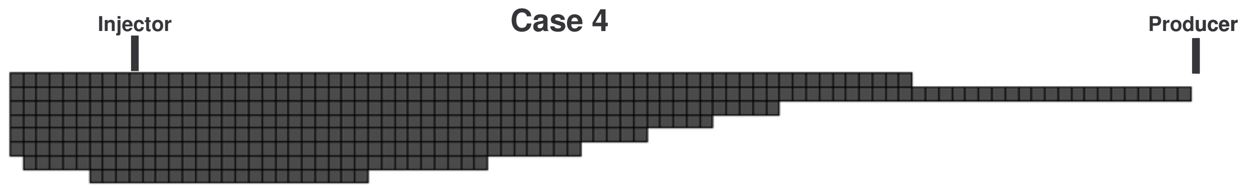

Fig. 9: Three-phase zone case 4: three-phase relative permeability hysteresis and trapping including capillary pressure.

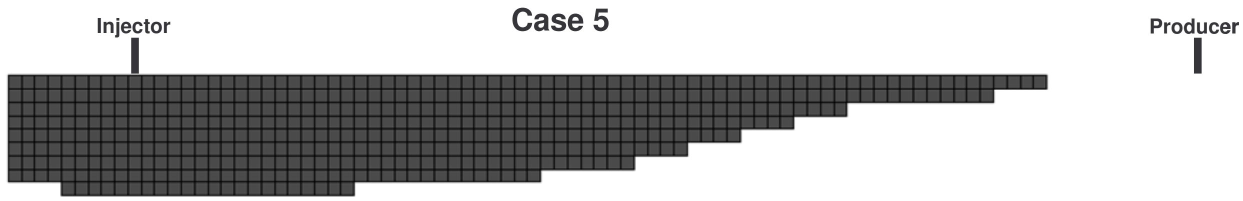

Fig. 10: Three-phase zone case 5: three-phase relative permeability hysteresis and trapping including capillary pressure and the effect of capillary pressure on relative permeability.

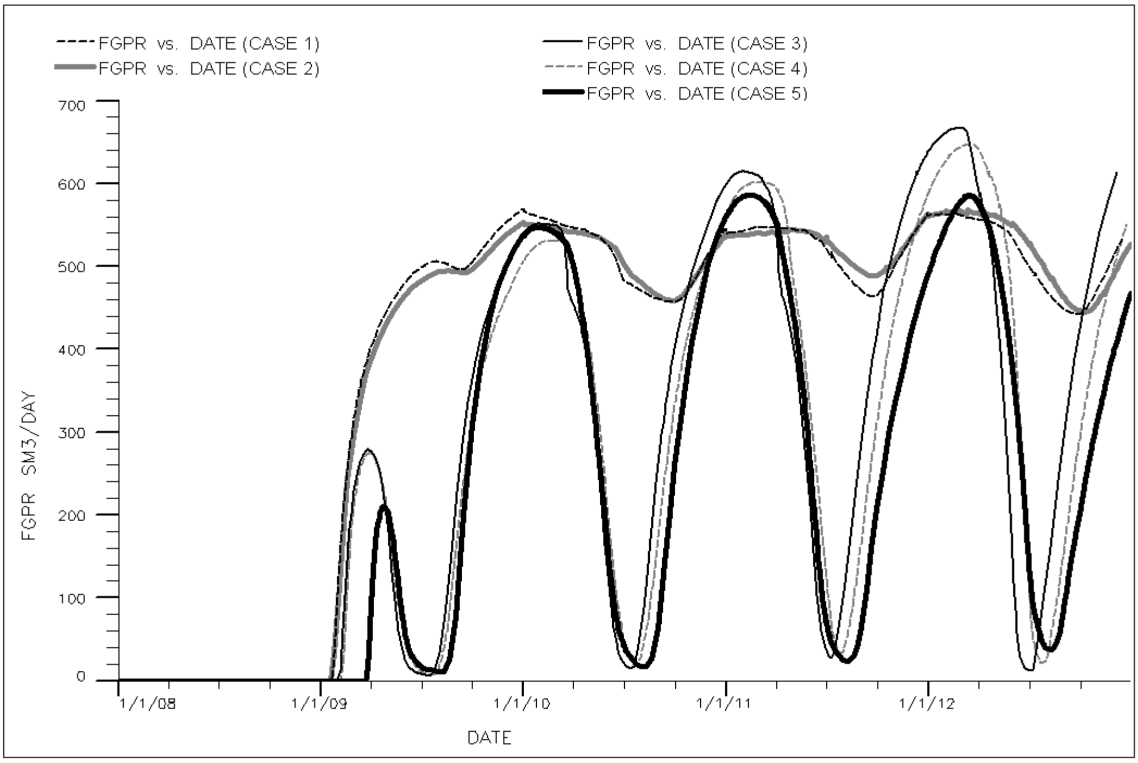

Fig. 11: Simulated gas production rate for case 1: two-phase relative permeability, case 2: two-phase relative permeability including capillary pressure, case 3: three-phase relative permeability hysteresis and trapping, case 4: three-phase relative permeability hysteresis and trapping including capillary pressure and case 5: three-phase relative permeability hysteresis and trapping including capillary pressure and the effect of capillary pressure on relative permeability.

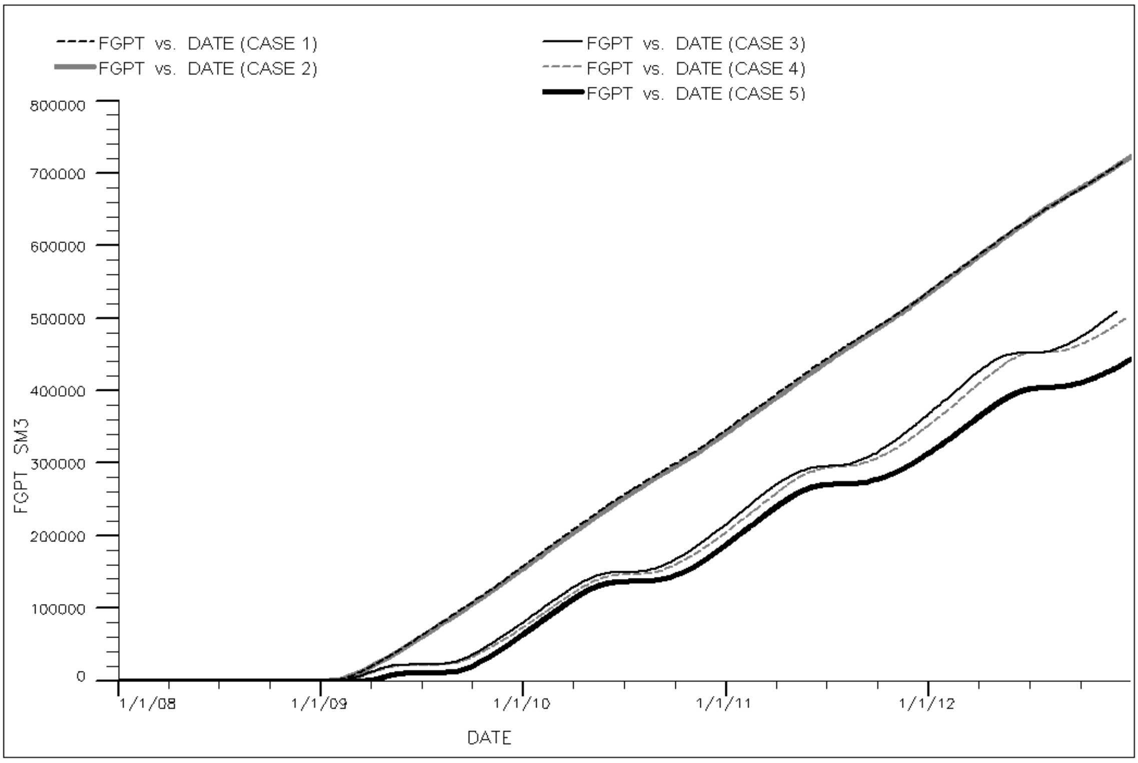

Fig. 12: Simulated total gas production for case 1: two-phase relative permeability, case 2: two-phase relative permeability including capillary pressure, case 3: three-phase relative permeability hysteresis and trapping, case 4: three-phase relative permeability hysteresis and trapping including capillary pressure and case 5: three-phase relative permeability hysteresis and trapping including capillary pressure and the effect of capillary pressure on relative permeability.

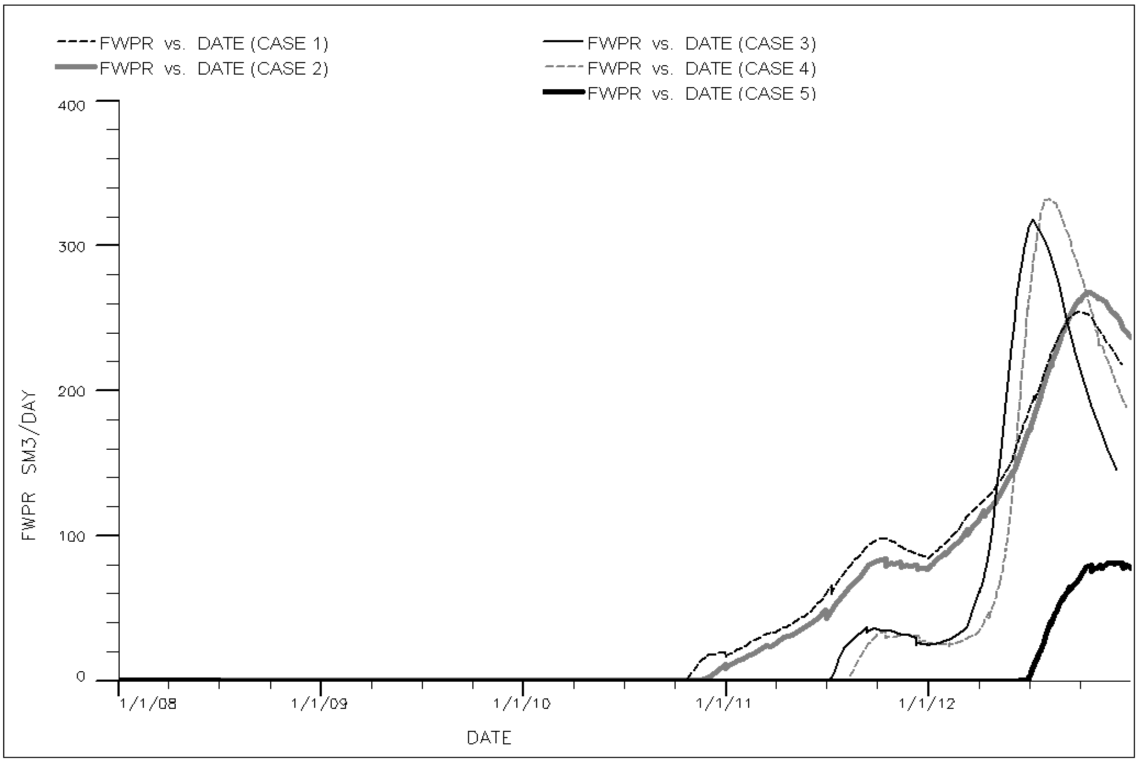

Fig. 13: Simulated water production rate for case 1: two-phase relative permeability, case 2: two-phase relative permeability including capillary pressure, case 3: three-phase relative permeability hysteresis and trapping, case 4: three-phase relative permeability hysteresis and trapping including capillary pressure and case 5: three-phase relative permeability hysteresis and trapping including capillary pressure and the effect of capillary pressure on relative permeability.

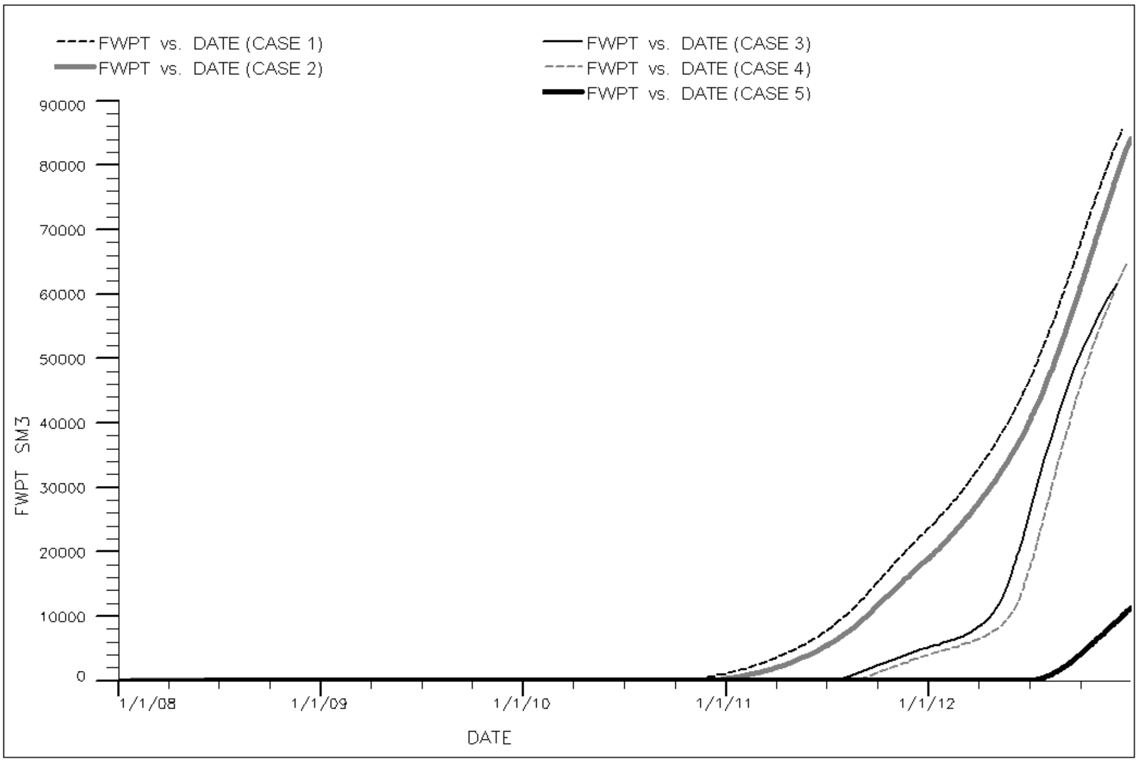

Fig. 14: Simulated total water production for case 1: two-phase relative permeability, case 2: two-phase relative permeability including capillary pressure, case 3: three-phase relative permeability hysteresis and trapping, case 4: three-phase relative permeability hysteresis and trapping including capillary pressure and case 5: three-phase relative permeability hysteresis and trapping including capillary pressure and the effect of capillary pressure on relative permeability.

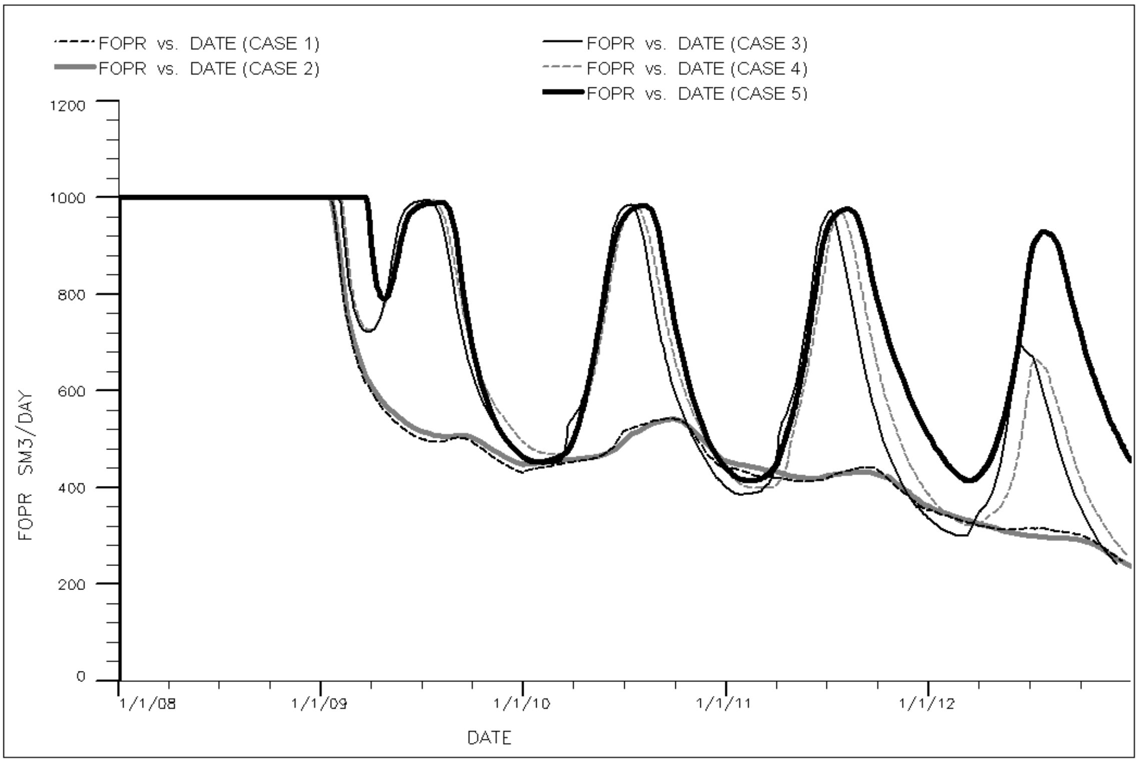

Fig. 15: Simulated oil production rate for case 1: two-phase relative permeability, case 2: two-phase relative permeability including capillary pressure, case 3: three-phase relative permeability hysteresis and trapping, case 4: three-phase relative permeability hysteresis and trapping including capillary pressure and case 5: three-phase relative permeability hysteresis and trapping including capillary pressure and the effect of capillary pressure on relative permeability.

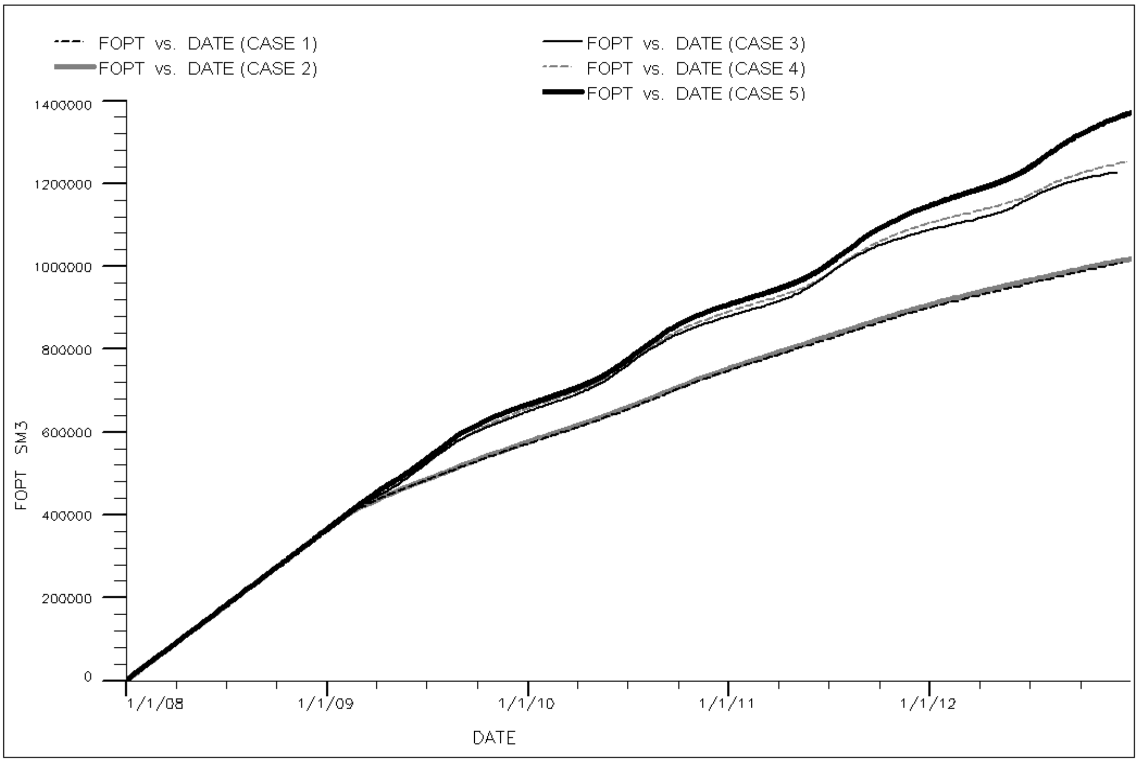

Fig. 16: Simulated oil recovery for case 1: two-phase relative permeability, case 2: two-phase relative permeability including capillary pressure, case 3: three-phase relative permeability hysteresis and trapping, case 4: three-phase relative permeability hysteresis and trapping including capillary pressure and case 5: three-phase relative permeability hysteresis and trapping including capillary pressure and the effect of capillary pressure on relative permeability.