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Simulation of Three-phase Flow in Porous Media Including Capillary Pressure Representing Variation in Rock Wettability

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SUMMARY

The effect of including a three-phase representation of the flow parameters has been investigated using a three-phase simulator in a black oil modulus. The simulation approaches include the complexity of three-phase flow, relative permeability hysteresis, dynamic phase trapping functions, and three-phase capillary pressure.

Three-phase flow in WAG processes are characterized by lower relative permeability of the injected fluids, because of flow path hysteresis and trapping of phases. In addition, three-phase capillary pressure gives a significant effect to the size of three-phase zone, breakthrough time and recovery. It is important to incorporate these effects to have a correct description of the physics of the multi-phase flow performance.

Three-phase capillary pressure is generated by network modeling for different wettability system. The significance of different three-phase capillary pressure representations is studies by varying wettability of the porous medium. Immiscible WAG cycles are investigated using a sector model.

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

Introduction

The oil recovery method water-alternating-gas (WAG) has proved to be a successful way to improve oil recovery compared to pure water injection or pure gas injection. Skauge et al. (2003) and Christensen et al. (2001) have reported a typical increased oil recovery around 5-10 percent of the initial oil in place due to WAG injection.

WAG injection can improves oil recovery by better sweep efficiency on both macroscopic and microscopic levels compared to gas injection or water flooding alone. The macroscopic sweep is improved both in the horizontal and vertical direction. The water restricts the mobility of the gas which influences the horizontal sweep, and the vertical sweep is improved because the gas segregates to the top and the water slopes to the bottom. Microscopic displacement efficiency is improved because the residual oil saturation after gas injection is lower than after water injection and in the three-phase zone the residual oil saturation can be even lower than after gas injection. The trapping of gas and water in the three-phase zone near the injection well may influence the local pressure field and lead the injection fluids towards new pathways, i.e. an improved microscopic sweep.

In most cases, capillary pressure has been neglected in application of these models in numerical simulations of WAG. The argument behind eliminating capillary pressure is to simplify the model, and the assumption that capillary pressure is of less importance for the problem analysed or because there are no experimental data available. Dale and Skauge (2007) shows that capillary pressure has a big impact on history match of relative permeability.

In other cases, two-phase capillary pressure has been used to represent three-phase flow. Kalaydijan (1992) performed a three-phase capillary pressure measurement and observed that three-phase capillary pressure is dependent on all phase saturations. This observation is confirmed by Virnovsky et al. (2004). These observations invalidate the usage of two-phase capillary pressure for process which involves three-phases.

This work tries to show the consequence of including three-phase capillary pressure in three-phase flow. As capillary pressure is very dependent on wettability, we performed numerical simulation on three types of wettability system, strongly water-wet (SWW), intermediate-wet (IW) and strongly oil-wet (SOW).

Three-phase capillary pressure is hardly measured due to its difficulty and very expensive to perform. Hence numerous efforts has been put into network model to predict three-phase behaviour. Several network models have been developed in recent years (Fenwick and Blunt, 1998; Mani and Mohanty, 1998; Øren et al., 1998; van Dijke and Sorbie, 2002; Valvatne and Blunt, 2004; Piri and Blunt, 2005)

Network model

A network model (3PhWetNet) has been used to generate both relative permeability and capillary pressure for two-phase and three-phase simulation. The network model is based on invasion percolation and the flow is dominated by capillary forces (van Dijke et al., 2001; can Dijke and Sorbie, 2002). The “3R approach” is used in the modelling (McDougall et al., 2001) which correlate network properties such as capillary entrance, pore volume and pore conductivity, with the pore size.

The network model consists of a three-dimensional network of pores with radius r. The distribution of pore radius (r) is taken from a given minimum and maximum radius together with the pore size distribution. In this study we have chosen Rayleigh type of distribution.

Initially, network is set as strongly water-wet system with contact angle ranging from 0.9 – 1.0. After ageing, contact angle is distributed according to its wettability system. Input fluid and pore properties for 3PhWetNet are listed in table 1.

Table 1. Pore properties for 3PhWetNet

Properties	Value
Pore Size Distribution	Rayleigh
Pore radius	0.2 – 29 μm
Standard deviation	1 μm
Coordination number	4
Volume exponent	1.0
Conductivity exponent	0.333
σ_{ow}	53 mN/m
σ_{og}	25 mN/m
σ_{gw}	72 mN/m
Initial contact angle, cos Ø	0.9 – 1.0
<u>After ageing</u>	
Strongly water-wet	0.8 – 1.0
Intermediate-wet	-0.3 – 0.3
Strongly oil-wet	-0.5 - -0.8

After oil-flooding, network model is run for water flooding (W1) and gas flooding (G1) until reaching maximum flooding saturation, to obtain two-phase oil-water and oil-gas saturation function (relative permeability and capillary pressure), respectively. Results from network model is smoothed against empirical equation for a more stable simulation. We employ Corey correlation for relative permeability and Skjæveland correlation for capillary pressure (Skjæveland et al., 2000).

Three-phase relative permeability is modelled using WAG hysteresis model (Larsen and Skauge., 1998). For this study, we use a typical value of Land constant (C = 2.0), drainage reduction factor (β = 5.0) and residual oil modification factor (R = 1.0). For simplicity, we have used the same coefficients for all cases. The WAG hysteresis model has been coded into UTCHEM, a three-dimension chemical flooding simulator.

Three-phase capillary pressure surface is obtained by simulating injection of one phase (primary process) until reaching a certain saturation followed by another phase injection (secondary process). This process is repeated for different saturation level which will give us a collection of saturation paths. We combined these paths as a surface using MATLAB surface fitting, as illustrated in figure 3.

Results from network model is process dependent hence we need to distinguish between process W1G2 (water flooding followed by gas flooding) and G1W2 (gas flooding followed by water flooding). In general, the absolute maximum three-phase oil-water capillary pressure is higher than two-phase capillary pressure during G1W2 process. Likewise, the absolute maximum three-phase oil-gas capillary pressure is higher than two-phase capillary pressure during W1G2 process. The possible explanation for this is due to lower accessibility in three-phase flow hence invading phase does not have access to as many pores as in two-phase flow.

It is evident from figure 3 that residual oil saturation is lower in three-phase flow compared to two-phase flow. This is similar with observation from Skauge et al. (1993), Skauge et al. (1994), Ma et al. (1994) and Dale and Skauge (2005).

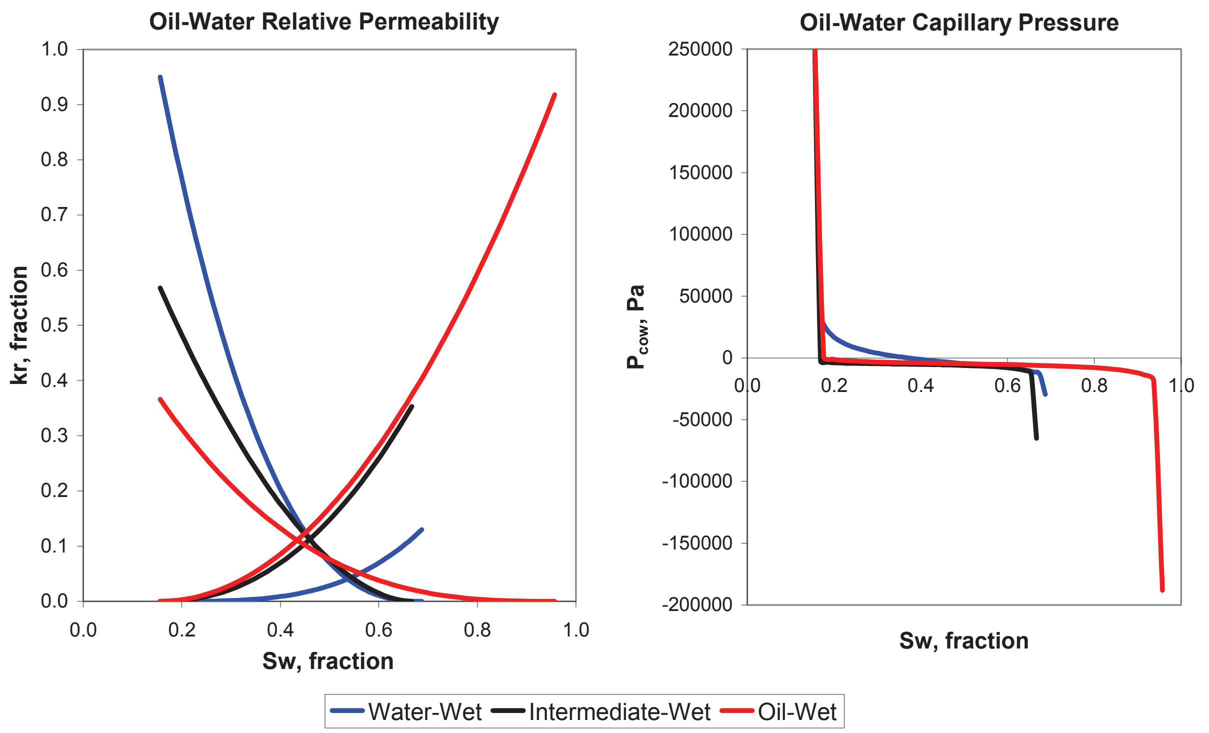

Figure 1. Smoothed two-phase oil-water relative permeability and capillary pressure from network model for different wettability system

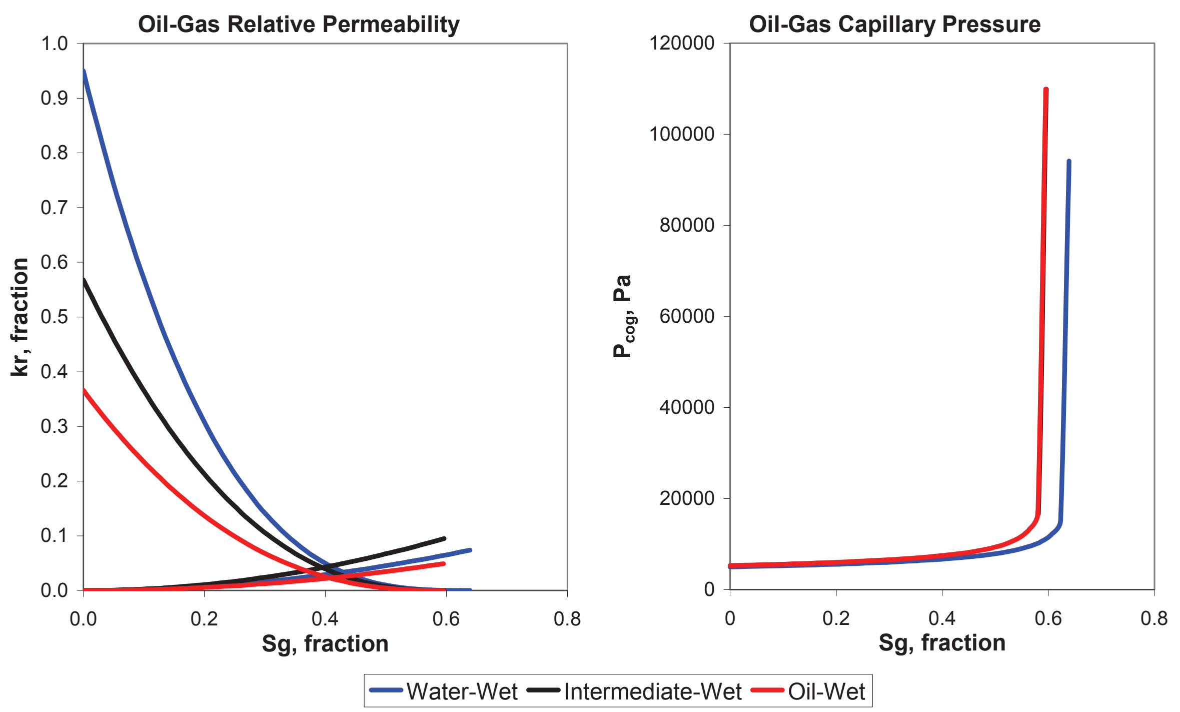

Figure 2. Smoothed two-phase oil-gas relative permeability and capillary pressure from network model for different wettability system

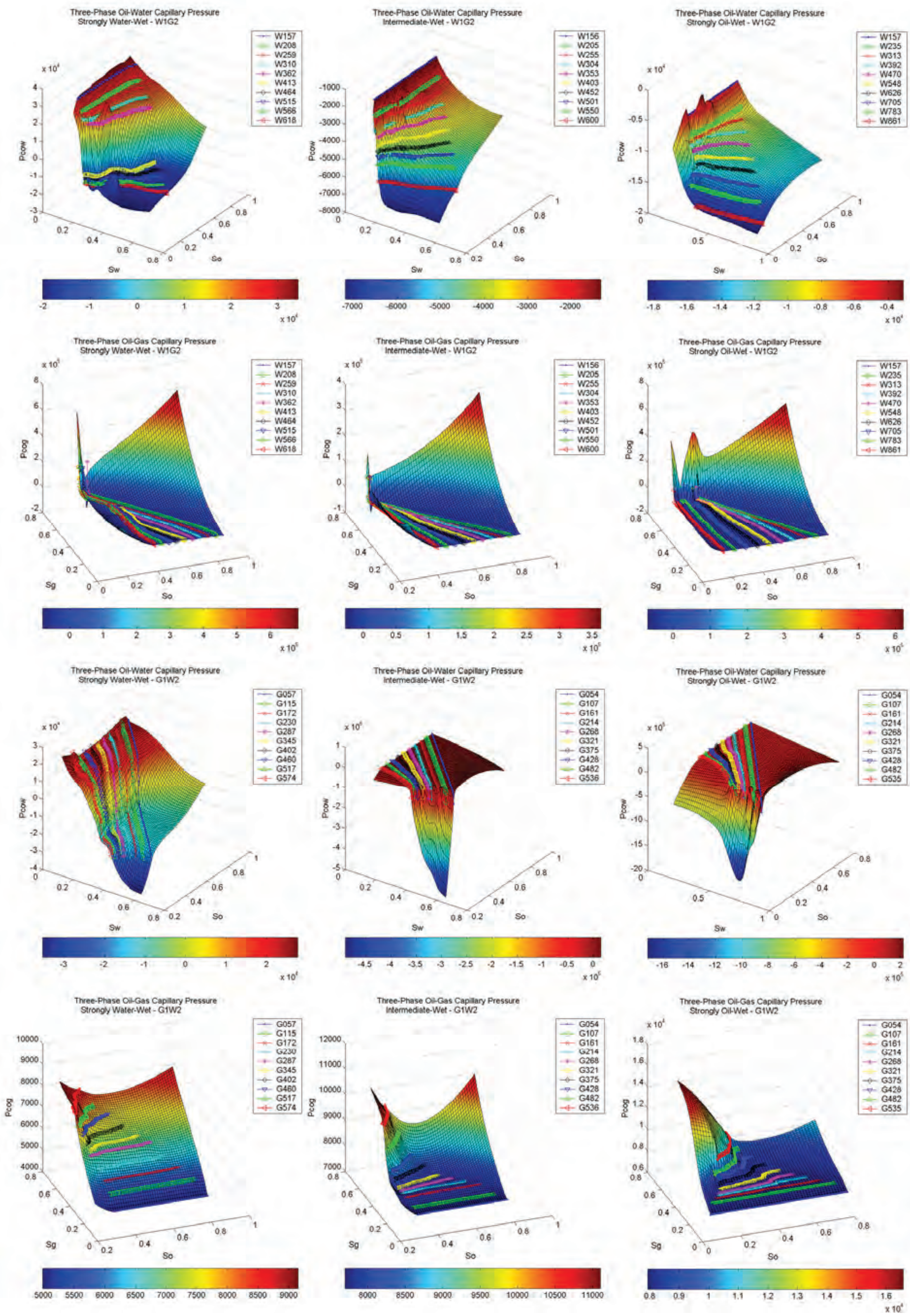

Figure 3. Three-phase oil-water and oil-gas capillary pressure W1G2 and G1W2 processes for different wettability system

Numerical Simulation

In order to evaluate the performance of each flooding process, we make a synthetic and homogeneous three-dimensional reservoir. Homogeneous model was chosen to isolate the effect of saturation function. The model is a quarter of a five-spot pattern in a horizontal reservoir. Injection well is set at one corner and production well is on the opposite corner, diagonally. Both wells are perforated in the middle of reservoir (layer 4-7). For simplicity, we have used PVT data which represent immiscible fluids (dead oil and dry gas). Parameters of the model are summarized in table 2.

Table 2. Key parameter for simulation model

Parameter	Value
Dimension	20 x 20 x 10
Block Size	$\Delta X = \Delta Y = 20$ m ; $\Delta Z = 7.5$ m
Porosity	0.25
Horizontal permeability	500
Anisotropy	0.1
Initial water saturation	0.844
Water density	1000 kg/m^3
Water viscosity	0.33 cp
Water compressibility	Uncompressible
Oil density	671 kg/m^3
Oil viscosity	0.442 cp
Oil compressibility	Uncompressible
Gas density	0.67 kg/m^3
Gas viscosity	0.033 cp
Gas compressibility	2.619×10^{-6} kPa^{-1}

The reservoir is initially saturated with oil and connate water. Initial reservoir pressure is set to 297 bar. Reservoir is injected with water and gas with same rate 3500 m^3/day. Production well is operated with total rate 3500 m^3/day. Water is injected for one year followed by gas with the same injection rate during W1G2 process. The same thing for G1W2 process where gas is injected for one year followed by one year water injection.

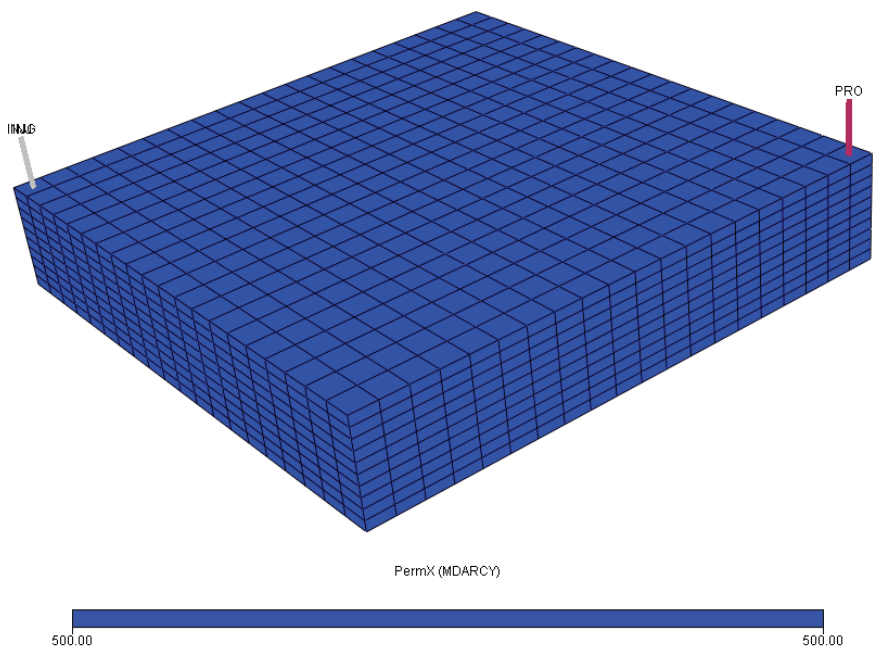

Figure 4. Three-dimensional synthetic model

Simulation Results and Discussion

The effect of three-phase capillary pressure on different wettability system is studied by comparing oil recovery efficiencies, production profile for each phase, three-phase saturation paths and three-phase zone.

Simulation results shows that maximum recovery is obtained by injecting gas followed by water in a strongly water-wet core. This result is agreed with observation by Skauge (1994).

In this case study we observed that G1W2 process gives the highest recovery regardless of wettability system. This observation is in contradiction with previous observation. Dale and Skauge (2005) observed higher oil recovery for oil-wet cores when water is injected first. While intermediate-wet cores have little dependence on which phase is injected first in a WAG scenario according to Skauge et al. (1993). The microscopic displacement efficiency of gas injection is higher at a more neutral or slightly oil-wet wettability than for a water wet situation. (Skauge et. al. 1993, Caubit et. al 2004) Possible explanation for this difference is that in this study, we did not inject until maximum oil recovery for each injection phase hence residual oil saturation is not achieved yet. While previous observation were based on laboratory experiments which inject a phase until reaching residual oil saturation.

Simulation results for both processes and different wettability shows that two-phase capillary pressure is not affecting recovery regardless to its wettability system. This is also contradicting with observation from Dale and Skauge (2007), probably because they performed simulation on core scale where capillary pressure is very dominant due to the dimensions of the model and slow injection rate.

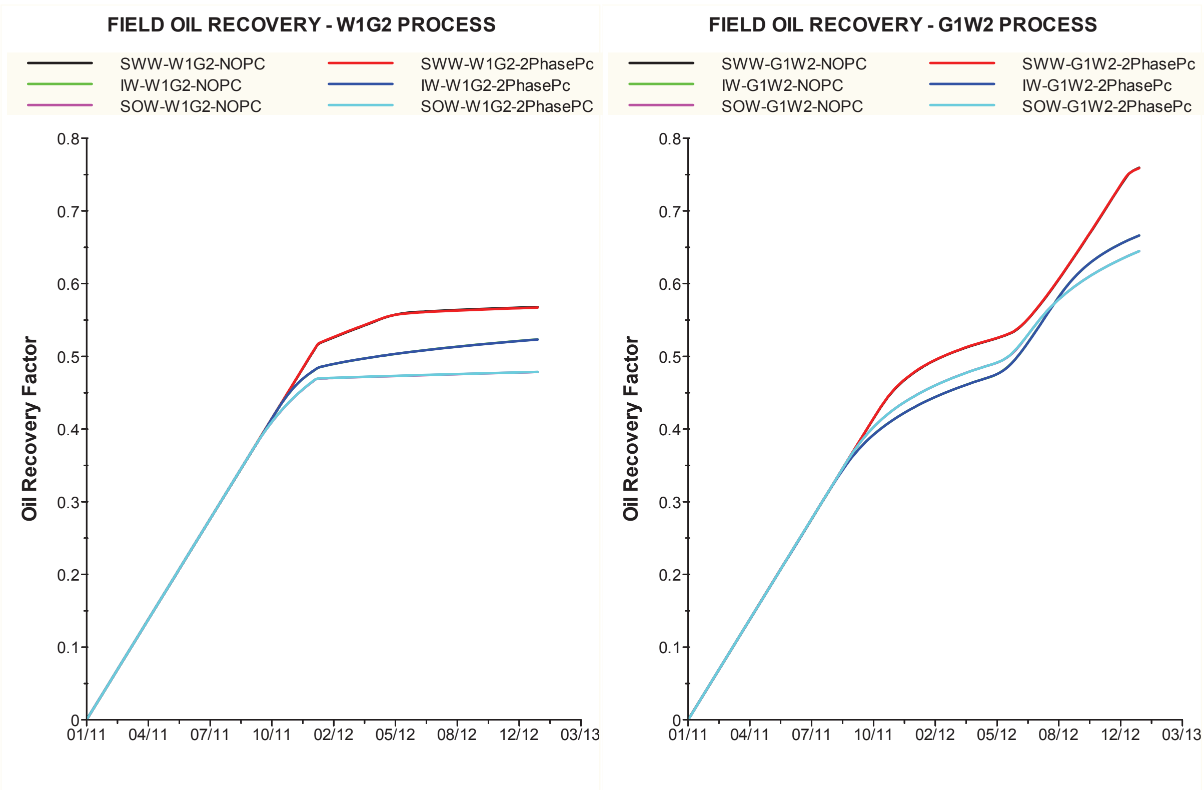

Figure 5. Recovery efficiency for different wettability system and different process, without capillary pressure and using two-phase capillary pressure

Including three-phase capillary pressure seems to affect oil recovery efficiency significantly. For W1G2 process, we can see a significant increase in oil production for all wettability system. The opposite behaviour can be seen for G1W2 process. For all wettability system, including three-phase capillary pressure significantly reduce oil production rate under the given constraints.

Effect of three-phase capillary pressure is the highest for strongly water-wet case with G1W2 process (decrease oil recovery by 16% IOIP), and strongly oil-wet case with W1G2 process (increase oil recovery by 12% IOIP).

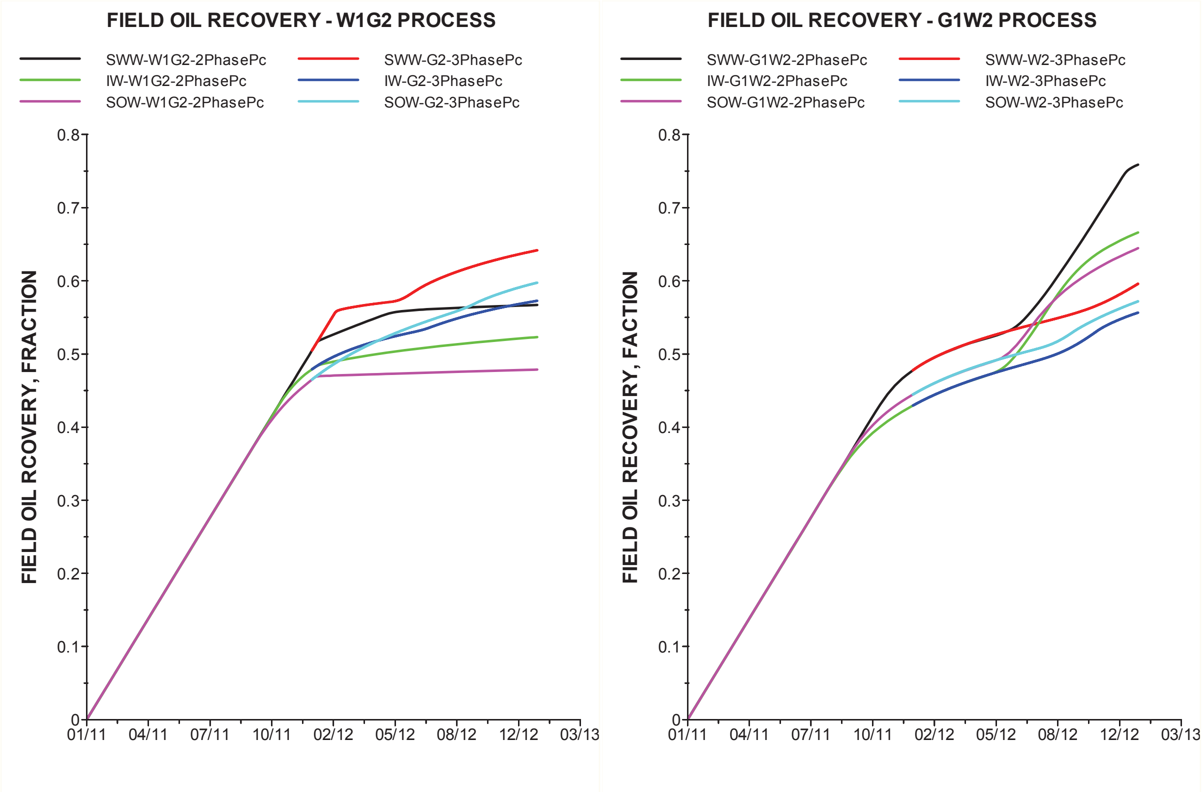

Figure 6. Recovery efficiency for different wettability system and different process, with two-phase and three-phase capillary pressure

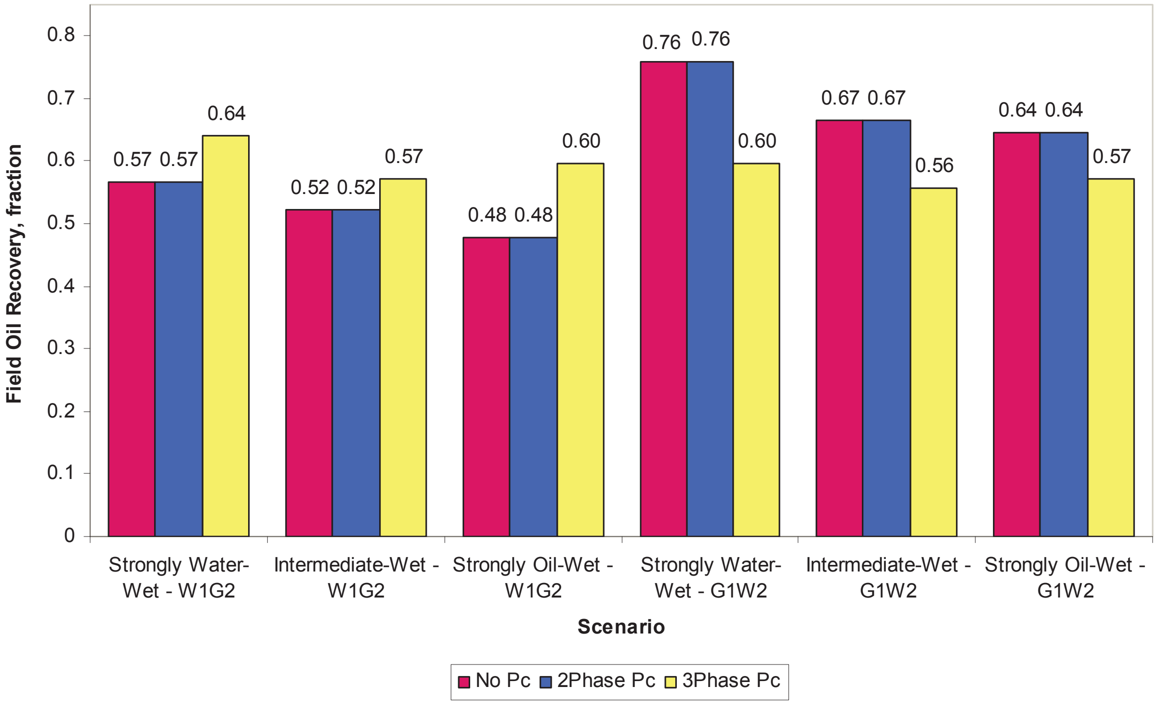

Figure 7. Field oil recovery at the end of simulation

Three-phase capillary pressure is also affecting water and gas production rate. Water production rate for W1G2 process increases significantly while its production rate is reduced in G1W2 process. Gas production rate is increase in all cases after including three-phase capillary pressure.

To evaluate fluid movement under influence of three-phase capillary pressure, we observe saturation changes at block (2,2,1) which is located next to injection well. Figure 10 and 11 shows the saturation path for each process. For strongly oil-wet W1G2 process, we noticed that saturation movement is relatively similar even after including three-phase capillary pressure. This is due to relatively low oil saturation at the starting of G2 process, which means that the process is close to two-phase flow.

Recovery efficiency in three-phase flow is often correlated with the size of three-phase zone. In three-phase zone, residual oil saturation will have a lower residual oil saturation. (Skauge, 1996). In this study, the three-phase zone is defined as blocks of the reservoir which has both mobile gas and mobile water. As critical gas saturation is zero and irreducible water saturation is 0.156, we set threshold for gas saturation of 0.01 and water saturation 0.16. General observation shows that including three-phase capillary pressure increase the extent of three-phase zone in W1G2 process and reduce the zone for G1W2 process. This result correlates very well with oil recovery profile suggesting that three-phase zone is affecting recovery efficiency.

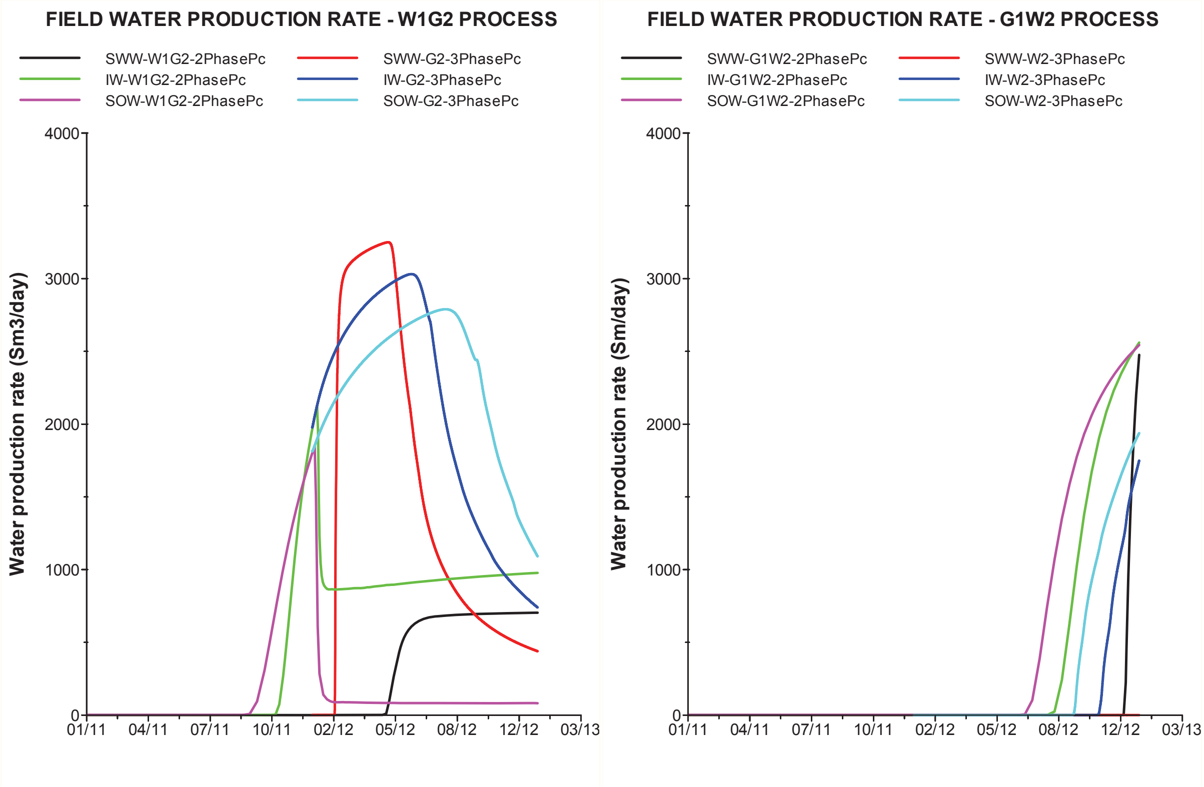

Figure 8. Water production rate profile for different wettability system and different processes, with two-phase and three-phase capillary pressure

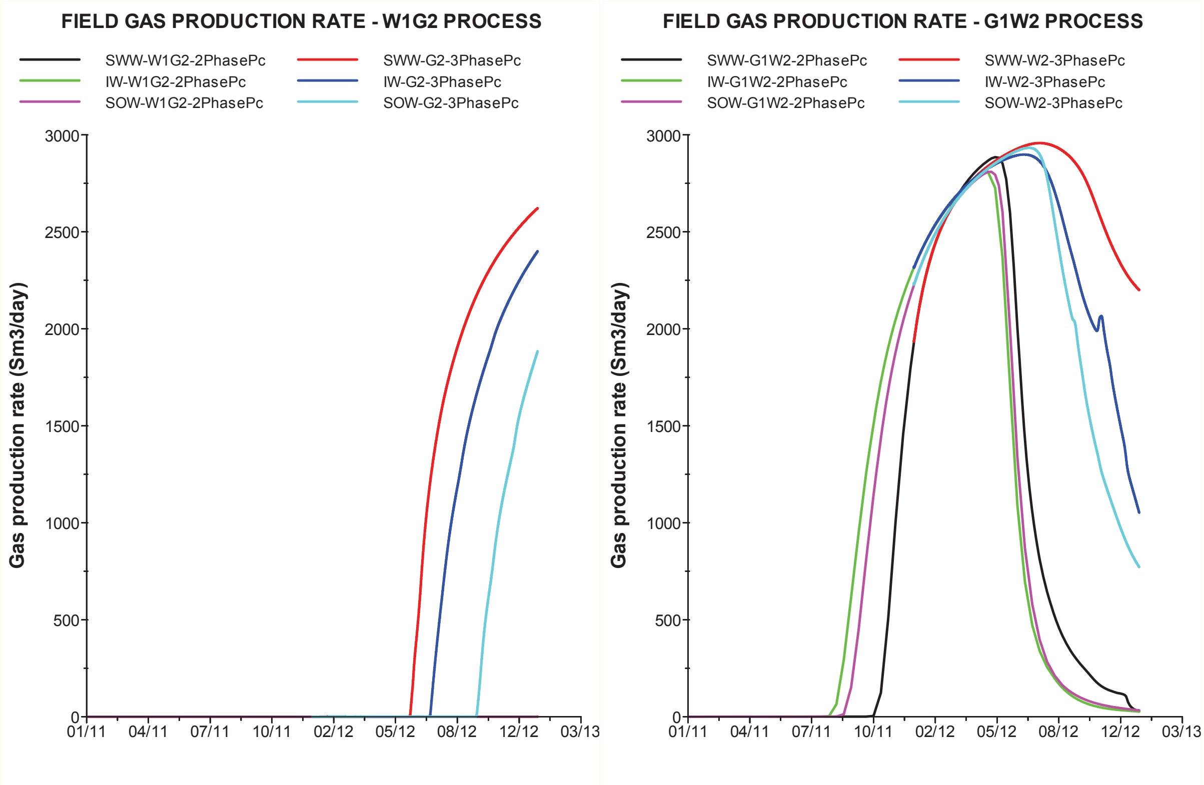

Figure 9. Gas production rate profile for different wettability system and different processes, with two-phase and three-phase capillary pressure

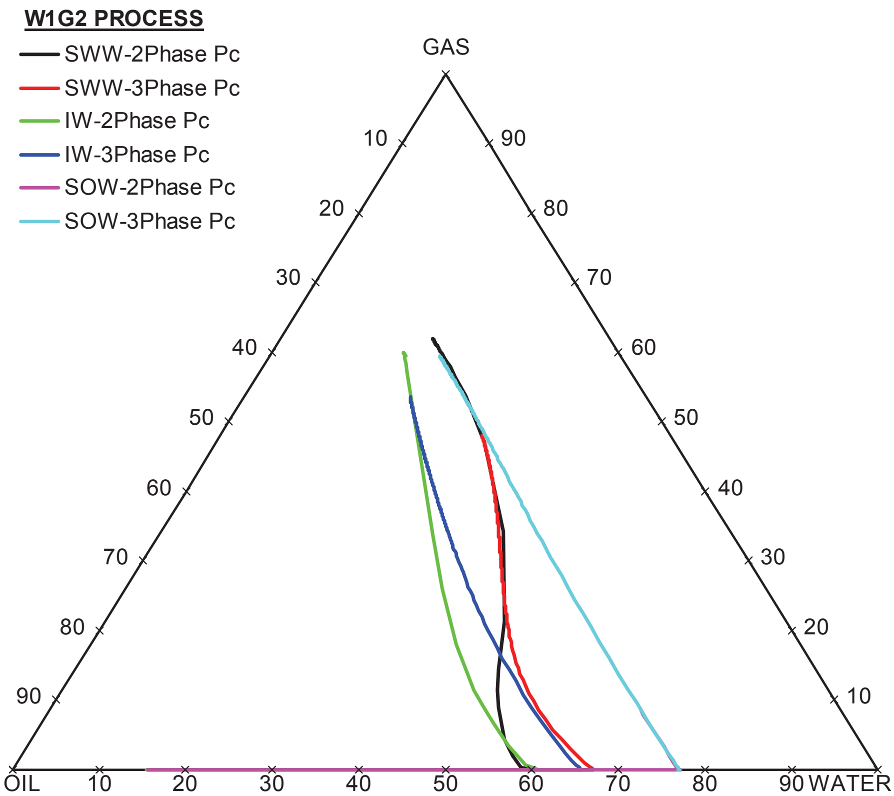

Figure 10. Saturation path at block (2,2,1) for different wettability system, W1G2 process, using two-phase and three-phase capillary pressure

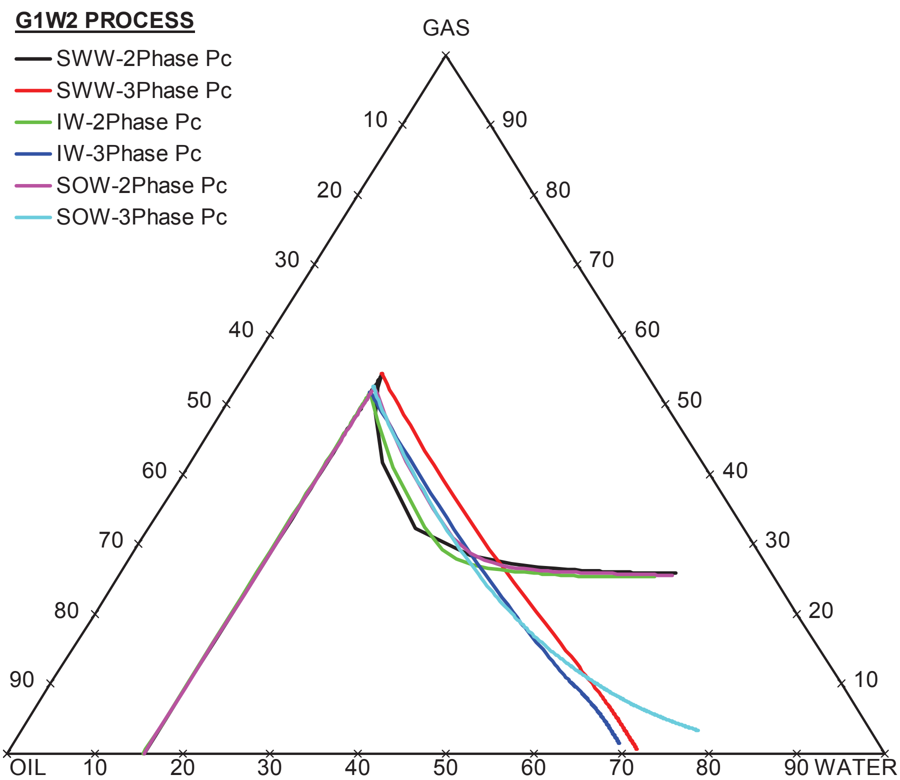

Figure 11. Saturation path at block (2,2,1) for different wettability system, G1W2 process, using two-phase and three-phase capillary pressure

Conclusions

This simulation study has investigated the effect of three-phase capillary pressure of field scale water/gas injection at different wettability. The simulations are run to a practical endpoint for oil production.

- Generated capillary pressure from network models anchored on two-phase data show that absolute maximum three-phase capillary pressure is higher than two-phase capillary pressure

- Introducing two-phase capillary pressure in the field scale simulations did not affecting oil recovery

- Including three-phase capillary pressure will increase oil recovery especially for W1G2 process while we observed reduced recovery for the G1W2 process

- Three-phase capillary pressure has the most influence in strongly water-wet cases for G1W2 and strongly oil-wet cases for the W1G2 process.

Acknowledgments

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