

SIMULATION OF THE EFFECTS OF HYDROPHILIC POLYMER ADSORPTION ON TWO-PHASE FLOW OF OIL-WATER MIXTURES

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ABSTRACT

Injection of water-soluble polymers in oil or gas producing wells can be an effective way to control water production where other technologies (gels, cements) cannot be applied. These treatments are relatively simple and inexpensive and the risk of impairing the permeability of the hydrocarbon producing layer is small. Numerical simulation techniques can then be useful to design and interpret laboratory tests and predict the performances of polymeric solution treatments in actual field conditions.

We first developed a simplified model of pore networks to evaluate changes in the effective permeability of the aqueous phase due to polymer adsorption, and then we implemented the obtained relationships between adsorbed thickness and water relative permeability into the TMVOC reservoir simulator (Pruess and Battistelli, 2002). The pore network is described according to an extension of V&P tube in series model, suitable also for fractured rocks (Verma and Pruess, 1988). The adsorbed polymer reduces the pore volume available for flow, thus reducing the effective permeability of the wetting phase compared to the original pore network. It is assumed that water and oil/gas relative permeability curves are conveniently described by a Corey's type function, with or without adsorbed polymer. The model estimates the reduction of water relative permeability and evaluates the new parameters of Corey's curve as a function of adsorbed polymer thickness. These parameters are regressed using polynomial correlations which are then supplied through the input file to a modified version of TMVOC simulator.

The adsorption isotherm parameters, as well as those necessary to evaluate the relationship between adsorbed mass and adsorbed layer thickness, can be evaluated by inverse simulation of core flood experiments, which is performed by running TMVOC under the PEST code (Doherty, 2002).

INTRODUCTION

Polymer adsorption dynamics is a complex process, the simulation of which requires a number of

assumptions and approximations. Theoretical models take into account basic adsorption mechanisms by means of semi empirical formulas (Denys, 2003), while most of the experimental approaches adopted so far found some difficulties in isolating the explicit polymer adsorption contribution to fluid permeability reduction, especially in a multiphase system (Singleton et al., 2002). Moreover, most of the models about polymer adsorption are focused on polymer gelification. Thus, reliable relationships between adsorbed polymer amount and average polymer layer thickness in non-gelification conditions are lacking.

Within this study we develop a geometrical model suitable for the evaluation of the reduction of fluids relative permeability due to the injection of a strongly hydrophilic polymer solution in the porous medium saturated with an oil/water two-phase mixture. The polymer is adsorbed on the walls of the porous medium network, thus interacting with water and oil phases and granting macroscopic water retention capabilities to the medium itself. We assume there is no gelification of the polymeric solution.

As a basic assumption, we consider the mixture of water, oil and polymer solution as a two-phase system where oil represents the non wetting phase, and both the water and polymer solutions are completely miscible and represent the wetting phase. We assume, also, that the main effect of the adsorbed polymer is to reduce water mobility in the pore volume affected by adsorption. As a simplifying hypothesis we consider the water mobility reduction to be 100% of the initial value, while we suppose that oil mobility is not affected by adsorbed polymers.

With such assumptions, we may summarize the essential consequences of polymer adsorption processes in the porous medium as follows:

- reduction of pore effective section available to the flow of water phase, leading to a reduction of water relative permeability;
- increase of the irreducible water saturation S_{wi} due to the increase of the immobile water fraction inside the porous medium volume.

We use Corey's type curves in order to describe oil and water relative permeabilities. This means that the

effects mentioned above are not independent, but are both described inside the modified expressions of relative permeability curves.

RELATIVE PERMEABILITY CURVES

Available experimental data show that water and oil relative permeability curves are modified by a polymer solution injection process in the qualitative way shown in Figure 1.

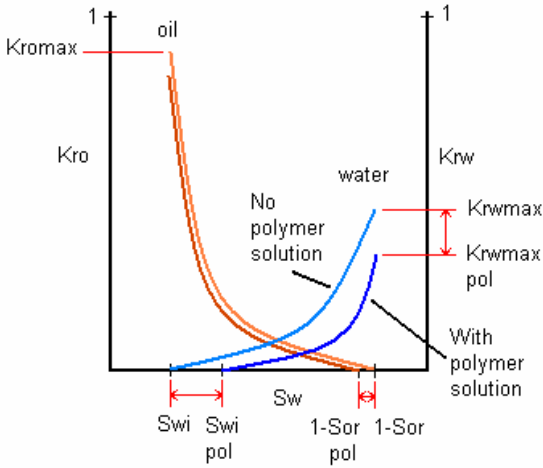


Figure 1. Qualitative modifications of relative permeability curves due to polymer adsorption process.

We may notice that oil relative permeability curve does not suffer substantial modifications, while the water relative permeability curve is strongly modified. Its modification can be described by a scaling process on both axes with respect to the original curve. We assume that the modified water relative permeability curve is always described by a Corey's function, whose characteristic parameters need to be modified according to the amount of polymer adsorption. In a first scale approximation we assume that Corey's curve parameters depend on two separate variables, namely the added irreducible saturation and the relative permeability scaling factor. These two variables are themselves a function of adsorbed layer thickness, that account for the two main effects of polymer adsorption described in the introduction.

Initial relative permeability curves

The initial relative permeability curves are Corey's type curves given in terms of end-points, whose exponent has been conveniently modified in order to have a unit permeability value at $S_w = 1$ for the water phase, and at a proper S_w value for the oil phase. The explicit equations of these curves are:

$$K_{rw}(S_w) = K_{rwm} \left[\frac{(S_w - S_{wi})}{(1 - S_{wi} - S_{or})} \right]^{EW} \quad (1)$$

$$K_{ro}(S_w) = K_{rom} \left[1 - \frac{(S_w - S_{wi})}{(1 - S_{wi} - S_{or})} \right]^{EO} \quad (2)$$

where K_{rwm} is the water relative permeability value at the saturation $S_w = 1 - S_{or}$, while K_{rom} is the oil relative permeability value at irreducible water saturation S_{wi} . In the following, we define as "end - points" the two points of coordinates:

$$P_w = (1 - S_{or}, K_{rwm}) \text{ and } P_o = (S_{wi}, K_{rom}).$$

The initial relative permeability curves considered, derived from published data relative to a Berea sand core, are shown in Figure 2.

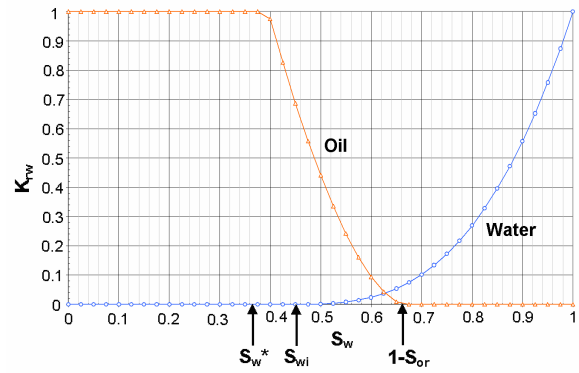


Figure 2. Relative permeability curves for oil and water without dissolved polymer.

In this plot water relative permeability curve is drawn assuming that $K_{rw} = 1$ at $S_w = 1$, while the oil relative permeability curve has $K_{ro} = 1$ at $S_w = S_w^*$ where S_w^* is the average value between water irreducible saturation S_{wi} and the water saturation value needed in order to maintain convexity for Corey's oil curve. The two conditions above lead to the following expressions for Corey's exponents:

$$EW = \frac{-\log(K_{rwm})}{\log \left[\frac{1 - S_{wi}}{1 - S_{wi} - S_{or}} \right]} \quad (3)$$

$$EO = \frac{-\log(K_{rom})}{\log \left[\frac{1 - S_w^* - S_{or}}{1 - S_{wi} - S_{or}} \right]}$$

Modifications of Corey's curves due to polymer adsorption

In our approach we always consider water to be the wetting phase, so we assume that the oil phase, located in the middle of the pores, is not affected by the polymer adsorbed on pore walls. Under this hypothesis we make the further assumption that Corey's oil relative permeability curve is modified only due to the increase of irreducible water

saturation caused by water entrapped in the adsorbed polymer solution volume. The latter limitation will be the subject of future developments.

Instead, the water relative permeability curve is modified by polymer adsorption as follows. Considering an adsorbed polymer layer of uniform thickness d in the pore walls, we may assume that the corresponding post-injection Corey's relative permeability $K_{rw, pol}(S_w)$ may be calculated by

multiplying the initial relative permeability by a suitable scaling function $\eta_w(d, S_w)$. The scaling function depends on water saturation and accounts for the reduction of effective pore section available for water phase flow due to polymer adsorption. The post-injection Corey's curve has the following expression:

$$K_{rw, pol}(S_w, S_{wi, pol}) = K_{rw}(S_w, S_{wi}) \eta_w(d, S_w) \quad (4)$$

where the irreducible water saturation $S_{wi, pol}$ is increased with the contribution of water entrapped in the adsorbed layer.

Once the two parameters $\eta(d, S_w)$ and $S_{wADD}(d)$ are determined, it is possible to draw the final water relative permeability curve, using equation (1), where EW and K_{rwm} are modified as follows:

$$EW_{pol} = -\log(K_{rwm, pol}) \left(\log \left[\frac{1 - S_{wi, pol}}{1 - S_{wi, pol} - S_{or}} \right] \right)^{-1} \quad (5)$$

$$K_{rwm, pol} = K_{rwm} \eta(d, S_w)$$

POROUS MEDIUM DESCRIPTION

It is possible to give an evaluation of $\eta(d, S_w)$ and $S_{wADD}(d)$ by means of a simplified porous medium model, based on an extension of the Verma and Pruess (1988) "pore series" model.

The V&P model describes the porous medium as a composition of channels whose axis is parallel to fluid flow. Each channel is made of two series-connected distinct pores, each of them with a different diameter, which follows a simple size distribution. The smallest pore of the series controls channel permeability, while the biggest one controls channel porosity. Channels may have a round or rectangular cross section, to account for cylindrical pores or fractures.

Our model extends these assumptions considering two different pore size distributions for each component of a single channel. Channels may be made of a great number of identical couples, in order

to consider the influence of cross-flow pore walls. The distributions are discretized and may be of any type, including those coming from experimental data. We also developed a simple model capable of estimating pore size distribution starting from experimental grain size distributions. More details about the V&P extended model are given by Carpita et al., (2006).

As regards the initial phases distribution among pores, we use a uniform thickness model. Depending on water saturation, we estimate the thickness of the water layer assuming it was uniform within the porous medium, whereas oil fills the remaining pore space. We base our equations starting from an original model proposed by Iwamatsu and Horii (1996). In this model an equation is suggested to estimate the layer thickness d_w of a wetting fluid (brine in our system) in a generic flow channel:

$$d_w = \frac{C_1}{\sqrt[3]{\rho\mu}} \quad (6)$$

Where ρ is the fluid density, μ is the chemical potential and C_1 is a constant depending on the kind of fluids and pore walls involved. The Young-Laplace equation may be used in order to have another expression for the product $\rho\mu$, while we may use the general expression of Brooks-Corey's (1966) function for capillary pressure p_c . p_e represents the entry pressure and is treated as a system parameter. We have the final expression:

$$d_w = C \left(\frac{S_w - S_{wi}}{1 - S_{wi}} \right)^{\frac{1}{3\lambda}} \quad (7)$$

where λ and C are parameters which may be estimated by means of the boundary conditions of $d_w(S_w)$ in the V&P extended model ($S_w = 1$ and $S_w = 1 - S_{or}$).

As far as the irreducible water saturation is concerned, we assume that the smallest pores of the distribution lead to a water capillary pressure high enough to prevent oil-induced displacement. Supposing an initial full pore filling with water, and a subsequent water drainage due to oil displacement, it is reasonable to assume that the whole channel connected to a small pore is not filled with oil. We assume that the whole channel volume accounts for water irreducible saturation. Summing the channel volumes containing irreducible water until the sum approaches the value of irreducible water saturation S_{wi} it is possible to determine the maximum value of small pore radius that prevents displacement.

Corresponding oil saturation is determined as $S_o = 1 - S_w$. Oil irreducible saturation does not require any modification, as it is assumed to be formed by oil droplets trapped inside the largest pores.

ADSORPTION MODEL

A simple adsorption model is considered based on experimental parameters and adsorption trends. As a basic hypothesis we assume the adsorbed polymer layer thickness to be constant along the pore walls, thus depending exclusively on adsorbed mass per unit surface. Figure 3 shows a scheme of this simple adsorption model in a cylindrical pore saturated by a two phase fluid mixture.

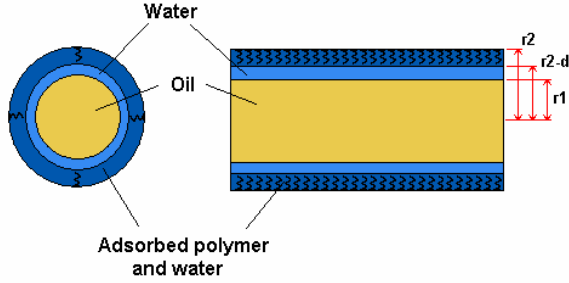


Figure 3. Geometrical model of phases distribution and polymer adsorption in a cylindrical pore.

Based on a semi-empirical model provided by Denys (2003) the polymer layer thickness d is expressed by a logarithmic function of polymer concentration C_{sol} of injected solution:

$$d = d_1 \ln \left(1 + \frac{C_{sol}}{C^*} \right) \quad (8)$$

This function is zero when $C_{sol}=0$, while its logarithmic trend takes into account the process of progressive accumulation and compaction of the adsorbed polymer layer. d_1 and C^* are two distinctive parameters, namely the thickness of a single adsorbed layer and the critical polymer solution concentration corresponding to semi-diluted regime. These two parameters are estimated as follows.

a) The parameter d_1 may be calculated considering a uniform polymer coverage of pore surfaces and a semicircular shape of the polymer chain between two bonding sites:

$$d_1 = \frac{1}{2} \frac{1}{\ln 2} \left(\frac{PM_{pol}}{PM_{mon}} N_c D_{CC} \right) \frac{1}{(\sqrt{N_{sites} S_1 - 1})(\sqrt{N_{sites} S_1 + 1})} \quad (9)$$

where PM_{pol} and PM_{mon} are the molecular weights of polymeric and monomeric particle respectively. N_{sites} is the number of bonding sites for surface unit, and it is treated as a matching parameter, while S_1 is the surface covered by a single polymer chain, which is a function of the adsorbed concentration C_{ads} and the total internal surface of pores S_{pores} , the latter being numerically evaluated in our extended V&P pore model.

It is possible to estimate this $S_1(C_{ads})$ by knowing rock porosity ϕ and its density ρ_{rock} , while C_{ads} may be calculated from an experimental adsorption isotherm, expressed in its more general formulation:

$$C_{ads} = \frac{b_i C_{sol}^{v_i}}{1 + a_i C_{sol}^{v_i}} \quad (10)$$

where b_i , a_i and v_i are matching parameters.

b) The parameter C^* may be calculated using a polymeric coil model described in Denys (2003), as:

$$C^* = PM_{pol} N_{coil} UMA \quad (11)$$

where N_{coil} is the number of polymeric coils for unit volume suspended in aqueous solution, which may be estimated with the following equation:

$$N_{coil} = \left(\frac{1}{75} \pi \frac{\eta PM_{pol}}{\Psi} \right)^{-1} \quad (12)$$

where Ψ is a suitable constant and η is the intrinsic polymer viscosity, which may be experimentally determined.

GEOMETRICAL MODEL OF PERMEABILITY MODIFICATION

From the definition of relative permeability for a generic phase i with a saturation value of S we have:

$$K_{ri}(S) = \frac{K_i(S)}{K_i(S=1)} \quad (13)$$

where the numerator represents the effective fluid permeability, while the denominator represents its absolute permeability. Adding a polymer solution in a system containing water will lead to an increase of irreducible water saturation, being the definition of water relative permeability still applicable. The scaling parameter η_w may be evaluated as:

$$\eta_w = \frac{K_{rw}(S_w)_{pol}}{K_{rw}(S_w)} = \frac{K_w(S_w, S_{wi})_{pol}}{K_w(S_w=1, S_{wi})_{pol}} \frac{K_w(S_w=1, S_{wi})}{K_w(S_w, S_{wi})} \quad (14)$$

where the general expression for relative permeability in the V&P model is as follows:

$$K_w(a, A) = N \int_0^a \int_b^A H(B, b) \left[\frac{1-\Gamma}{k_b} + \frac{\Gamma}{k_B} \right]^{-1} dB \quad (15)$$

b and B are the pore couples radii, a and A are their maximum values in the distribution, N is the number of pores for surface unit, Γ is the length ratio between larger and smaller pores within a single channel. $H(B, b)$ is the distribution function of pore couple of B and b radii. k_b and k_B are the single pore couple permeabilities, calculated as absolute or effective permeabilities depending on the term considered in equation (15).

Absolute pore couple permeabilities are given by

$$k_{Tb} = \frac{\pi b^4}{8} \text{ and } k_{Fb} = \frac{b^3}{12} \text{ for round and rectangular}$$

pore sections respectively, while effective pore couple permeabilities are evaluated in a geometrical way computing them in terms of absolute permeabilities in a reduced pore section, due to the presence of oil phase. For round section pores, assuming the water phase forms an annulus around pore walls, it is possible to analytically calculate its permeability with a suitable extension of the annular pore permeability in a single phase system. The water effective saturation for fractures can be calculated more easily by means of the absolute permeability equation in a reduced volume.

As far as the increase of irreducible water saturation S_{wADD} is concerned, the general formula leads to:

$$S_{wi}^{pol} = \frac{V_{H_2O_{imm}} + V_{H_2O_{pol}}}{V_{pores}} = S_{wi} + \frac{V_{H_2O_{pol}}}{V_{pores}} = S_{wi} + S_{wADD} \quad (16)$$

where S_{wADD} may be numerically evaluated by summing the pore volume adjacent to pore walls covered by a polymer layer of thickness d , as given by equation (8).

In Figure 4 we show the predicted modifications of original water and oil relative permeability curves due to uniform polymer layer thicknesses varying from 0 to 0.9 microns. Notice that oil relative permeability curves show very little changes due to the sole process of irreducible water saturation increase. The modified curves are once again described by means of Corey's type relative permeability functions, whose characteristic parameters are functions of adsorbed layer thickness. Corey's curve parameters are then expressed using a fitting procedure as polynomial functions of adsorbed layer thickness d as shown for the exponent EW in Figure 5.

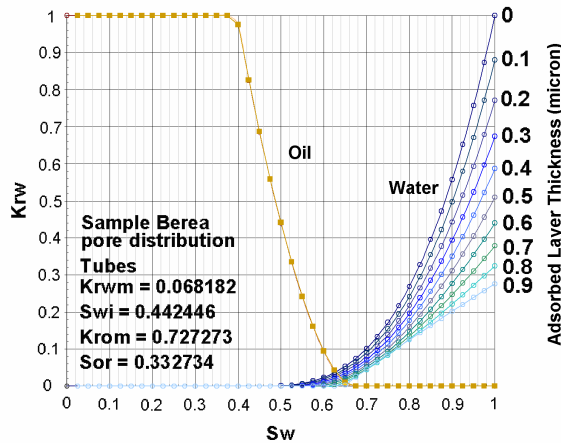


Figure 4. Modifications of initial water and oil Corey's curves versus adsorbed layer thickness with sample parameters.

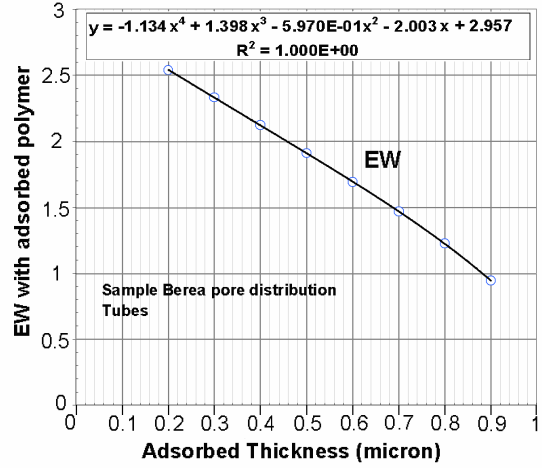


Figure 5. Sample plot and analytical fit of EW versus adsorbed polymer thickness.

Similar curves are obtained for S_{wi} and K_{rwm} parameters. Polynomial fits are used to evaluate the new Corey's permeability modifiers as a function of adsorbed layer thickness inside the TMVOC numerical reservoir simulator.

TMVOC IMPROVEMENTS

The TMVOC code (Pruess and Battistelli, 2002), belonging to the TOUGH2 family of reservoir simulators, is designed for simulating three-phase non-isothermal flow of water, soil gas and a multi-component mixture of volatile organic chemicals in multidimensional heterogeneous porous media. Some improvements were implemented in a modified version of the code to model the thermophysical properties of polymeric solutions and the relationship between porosity and effective phase permeability as described by the extended V&P porous medium model. The main code modifications include:

- *Computation of aqueous phase density and viscosity.* It is assumed that aqueous solution density and viscosity at given pressure, temperature and salinity, can be computed starting from the density and viscosity of a brine at the same conditions, multiplied by a polynomial function of polymer mass fraction
- $$f(X_{pol}) = 1 + a_1 X_{pol} + a_2 X_{pol}^2 + a_3 X_{pol}^3 + a_4 X_{pol}^4 \quad (17)$$
- whose coefficients must be experimentally determined.
- *Polymer Adsorption* is treated as an equilibrium process. Polymer adsorbed mass on the rock surface is evaluated by means of a generalized adsorption isotherm, with three adjustable parameters:

$$M_s^{pol} = (1 - \phi) \rho_R f_{oc} K_{OCM} \frac{(\rho_W X_w^{pol})^{K_{OC3}}}{1 + K_{OC2} (\rho_W X_w^{pol})^{K_{OC3}}} \quad (18)$$

In this way, linear, Langmuir and Freundlich isotherms can be modeled.

- *Adsorbed polymer thickness.* It is evaluated using the model described previously, coded into a new subroutine, starting from the adsorbed polymer mass per unit rock surface.
- *Relative permeability curves.* The aqueous phase mobility decreases due to polymer adsorption following the model described previously. The parameters controlling Corey's relative permeability of the aqueous phase are functions of adsorbed polymer thickness. They are evaluated inside subroutine RELP using polynomial correlations as a function of the adsorbed polymer thickness, whose coefficients are supplied through the input file of TMVOC.

SAMPLE CODE APPLICATIONS

Unknown parameters of relative permeability curves and of generalized adsorption isotherms can be determined by means of inverse simulation (IS) using the results of core flooding experiments. Here below, two different applications performed as code verification tests are discussed. They are performed running TMVOC coupled with the PEST code (Doherty, 2002), a model independent parameter estimator. PEST adjusts the model parameters until model-generated results fit a set of observations as closely as possible, that is, until the fit between model outputs and laboratory or field observations are optimized in a weighted least squares sense.

Since experimental data suitable for numerical simulations were not yet available, the results of predictive simulations (PS) of core flooding experiments were used as *synthetic* experimental data. In both applications the 10 cm core is discretized with a 1D horizontal grid of twenty elements of 0.5 cm width, having a cross sectional surface of $0.5067 \times 10^{-3} \text{ m}^2$. At the core outlet, an additional inactive element is used to assign the boundary conditions, held constant and equal to the initial conditions within the core: temperature of 20°C, pressure of 2 bar abs. Main rock properties, relative to a Berea sand, are listed in Table 1.

Table 1. Main rock properties.

| | |
|----------------------------|------------------------|
| ϕ | 0.2195 |
| $k \text{ (m}^2\text{/s)}$ | 4.54×10^{-13} |
| S_{wr} | 0.442446 |
| S_{or} | 0.332734 |
| K_{rwm} | 0.068182 |
| K_{rom} | 0.727273 |

Test A: Calibration of relative permeability curves

The aim of the simulation is to verify that the unknown parameters of relative permeability curves can be determined by inverse simulation reproducing

the observations made during a core flooding experiment.

The core is assumed to be initially saturated with oil and a 2% by mass sodium chloride brine, the latter at irreducible saturation. Brine with the same salinity is injected at a constant rate of 60 ml/h. The pressure gradient at the opposite sides of the core and the cumulative volumes of oil and water produced at the core outlet, generated in a preliminary simulation, are used as the observations to be matched running TMVOC coupled with PEST, considering the relative permeability parameters listed in Table 1 as the unknown parameters to be determined. The optimized values are reported in Table 2. Figure 6 shows the profiles along the core length of pressure and mass fraction of an inactive tracer dissolved in the injected brine. Figure 7 presents a comparison between synthetic experimental data and inverse simulation results.

Table 2. Parameters of relative permeability curves optimized with the inverse simulation

| | |
|-----------|----------|
| S_{wr} | 0.442540 |
| S_{or} | 0.332760 |
| K_{rwm} | 0.068164 |
| K_{rom} | 0.726296 |

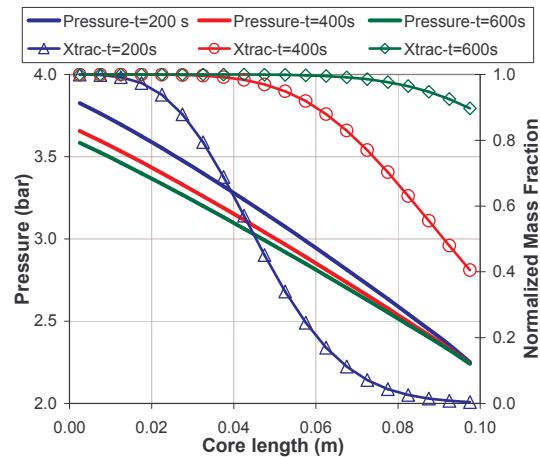


Figure 6 Test A: Pressure and normalized tracer mass fraction profiles along the core, at different injection times.

Other simulations performed indicate that the relative permeability curve parameters are determined with an acceptable accuracy even when the pressure gradient across the core is the only matching observation available.

Test B: generalized adsorption isotherm

The purpose of this simulation is to evaluate, by means of measurements of pressure gradient and polymer concentration, the generalized adsorption

isotherm coefficients and the N_{sites} parameter of equation (9).

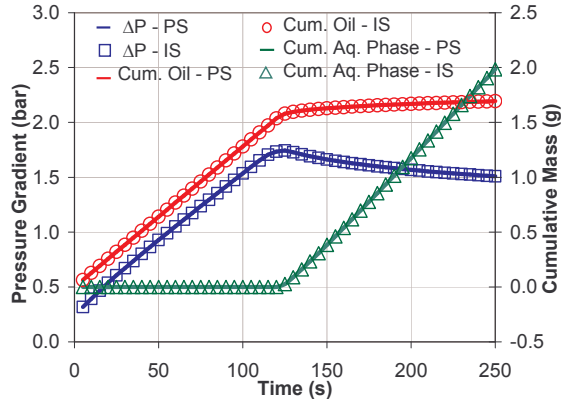


Figure 7 Test A: matching of synthetic experimental data with inverse simulation results.

The oil saturated core with brine at the irreducible saturation previously described is still considered. A diluted 0.002% by mass polymer solution with 2% sodium chloride is injected for 2000 s at a constant volumetric rate of 60 ml/h. The predictive simulation performed to generate the synthetic experimental data is carried out assuming that the adsorption process follows a Langmuir type isotherm, whose parameter values are reported in Table 3.

Table 3. Values of parameters to be optimized (PS) and inverse simulation results (IS).

| | PS | IS |
|--------|-------------|-------------|
| Koc | 4.38732E-04 | 4.11412E-04 |
| Koc2 | 6.85498E+00 | 6.41933E+00 |
| Koc3 | 1.00000E+00 | 1.00783E+00 |
| NSITES | 1.54000E+01 | 1.54124E+01 |

Looking at the pressure profile along the core shown in Figure 8 for different injection times, two different gradients can be observed, in front and behind the dissolved polymer front. Comparing the concentration profiles of polymer and of an inactive tracer, it is clear how the adsorption process retards the polymer transport inside the core. Moreover, by comparing Figure 8 with Figure 6 we observe that, at the same injection time, the presence of polymer leads to a higher pressure profile, due to the reduced aqueous phase mobility.

The best fit process was running accounting for the pressure gradient between the opposite sides of the core measured every 20 s, and for polymer mass fraction at the outlet section every 60 s, for a total of 133 observation points.

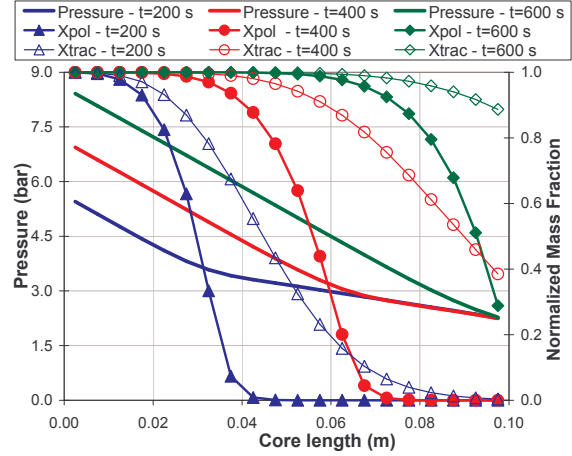


Figure 8. Pressure, normalized polymer and tracer mass fraction profiles along the core, at different injection times.

The inverse simulation provides the parameter estimates listed in Table 3. Figure 9 shows the good agreement between the synthetic experimental data and the inverse simulation results, as far as the pressure gradient across the core and the polymer concentration in the brine at the core outlet are concerned. It can be noted that the exponent in the generalized adsorption isotherm Koc3 is slightly higher than 1.

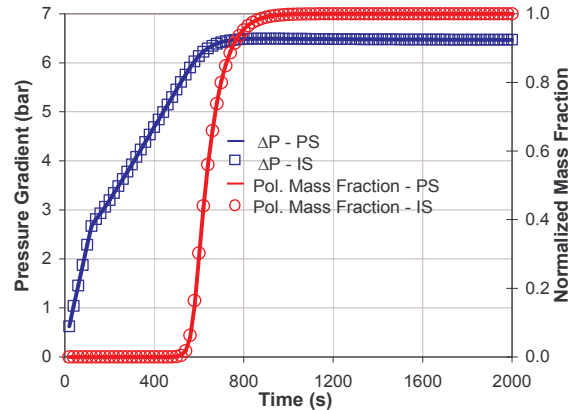


Figure 9. Test B: matching of synthetic experimental data with inverse simulation results.

CONCLUSIONS

A semi empirical method based on a simplified description of porous medium able to provide an estimate of effective permeability reduction in a two phase oil-water system due to polymer adsorption processes has been developed. The method includes:

- a description of pore network (Caripita et al., 2006) based on an enhanced version of the tube in series model of Verma and Prues (1988);
- a novel description of the change of wetting phase effective permeability as a function of the thickness

of polymer adsorbed on the walls of the pore network;

- an evaluation of adsorbed polymer thickness as a function of the mass of adsorbed polymer per unit volume of porous medium;
- the description of polymer adsorption as an equilibrium process following a generalized adsorption isotherm;
- the modification of the TMVOC reservoir simulator to conveniently model the transport of a polymeric diluted solution in a two-phase system, the adsorption of polymer and the associated changes of wetting phase relative permeability as a function of adsorbed thickness.

Using TMVOC running under the PEST code, the capability of evaluating unknown parameters by matching synthetic experimental results through inverse modeling have been verified. Observations conventionally recorded during core flooding experiments have been used for this purpose.

Further improvements of the proposed approach will be focused on a better estimate of oil relative permeability modification model and on the refining of polymer layer formation mechanisms. The next phase of the study foresees the validation of the described methodology against true laboratory core flooding experiments.

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