MATRIX IMPACT ON THE RESIDUAL RESISTANCE FACTOR ESTIMATION OF POLYMER SOLUTIONS IN DUAL-POROSITY SYSTEMS: AN ANALYTICAL AND EXPERIMENTAL STUDY

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Abstract

The main focus of this study was The analytical and experimental determination of the residual resistance factor in a fractured medium taking into consideration both the matrix and fracture contributions to fluid flow. In a previous study, the authors showed that the residual resistance factor in a fractured medium was dependent on a dimensionless parameter called coil overlap, which is a function of both intrinsic viscosity and polymer concentration, and Power Law Equation parameter of a polymer [1]. However, as the experiments were conducted exclusively on glass micromodels, the matrix role was neglected. Therefore, in the analytical models developed for this study, for simplicity and practicality, it was assumed that the matrix flow contribution was negligible. The analytical solution of this theoretical model and the associated core-flood experiments showed that taking into account the role played by the matrix could significantly reduce error and improve the agreement between analytical and experimental results. Similar to the previous study, the parameters considered in this study were the polymer concentration, power law constitutive equation parameter, salinity, sulfonation content of the polymer, temperature, and molecular weight of the water-soluble polymers, which are used in polymer flooding for enhanced oil recovery.

Introduction

It is now considered common knowledge that substantial amounts of the remaining oil reserves are of types with very high viscosity and a range of gravities. However, the research community has a long history of working with crudes with high viscosity and relatively low API gravities [2], mostly in the clastic sedimentary rocks. Various EOR methods have been proposed for recovery of these crudes, among them thermal methods, microbial injections and chemical injections. Chemical injection methods comprise injection of surfactants, biosurfactants and polymer injection. What is lacking in this process is a study covering the recovery of crudes, which are not necessarily classified as heavy by polymer injection, from fractured carbonate rocks considering both the roles being played by fracture and matrix [3].

Various types of polymers have been utilized in the oil and gas industry. Partially hydrolyzed polyacrylamides (HPAM) and xanthan polysaccharides have been the leading polymers used in enhanced oil recovery (EOR). These two types are considered as the most cost effective types of polymers. Associative polymers have been investigated as a possible substitute for HPAM polymers in EOR applications. For hydrophobic associative polymers, incorporation of a small fraction of hydrophobic monomer into an HPAM polymer enhances intermolecular connections, thereby enhancing viscosities and resistance factors. At moderate concentrations, these polymers can provide considerably higher viscosities than polymers with equivalent molecular weights without hydrophobic groups [4].

Injection of a dilute solution of a water-soluble polymer, in this case partially hydrolyzed polyacrylamide (HPAM), to increase the viscosity of the injected water can increase the amount of oil recovered in some formations [5]. This polymer acts in three ways: 1) by impacting the fractional flow, 2) by reducing water mobility, and 3) by diverting the injected water to the non-invaded zones [2]. The ratio of the mobility of water to the mobility of a polymer solution under the same conditions is defined as the resistance factor (RF) [3] as follows:

$$RF = \frac{K_w}{K_p}\frac{\mu_p}{\mu_w} \tag{1}$$

whereas K_w and K_p are water- and polymer-relative permeabilities and μ_w and μ_p are water and polymer viscosities, respectively. Residual resistance factor (RRF) is another useful parameter, which is defined as the ratio of the initial water mobility to the water solution mobility after polymer flooding [3]. This definition, together with the definition of mobility ratio, which is mobility of water as the displacing fluid to mobility of oil as the phase being displaced, clearly explains the added value of polymers.

Enhancing the already established correlation between RRF and polymer concentration, water salinity, molecular weight of the polymer and temperature as the main objective of this study will be discussed in detail in proceeding sections. Eventually, residual resistance factor as a quantified parameter implicitly representing several characteristics of the polymer can serve in high-level studies for screening and identifying a fit-for-purpose EOR method.

Materials and Methods

Theory

In a previous study by Ramazani et al. [1], the following equation was developed correlating RRF, intrinsic viscosity and polymer concentration:

$$RRF = \exp\left([\eta]c - \ln\frac{4n_c}{3n_c+1} \right) \tag{2}$$

where n_c is a the power law constitutive equation parameter for the polymer concentration, c , and the intrinsic viscosity multiplied by polymer concentration is a dimensionless number called coil overlap parameter. Merely taking into account the significant role of the fracture as a flow conduit, the impact of matrix has been neglected in Equation (2), which potentially introduces a marked error in calculating the resistance factor. The attempt was made to factor the impact of flow into the matrix in the previous equation. To this end, in a model defined according to the conceptual model shown in Figure 1, the number of capillary tubes may be calculated with the following correlation for a core plug of diameter D with a longitudinal fracture of length L and an average opening of d .

$$n_f = \frac{L}{d} \tag{3}$$

The assumption to treat a 2-dimensional (actually, 3-dimensional) fracture with a series of one-dimensional tubes is true only when the fracture thickness in the 3rd dimension does not exceed a certain amount. This somehow falls into the category of micro fractures. The total flow rate of the core is equal to the flow rates of matrix and fracture. So, Equation (3) can be expanded for total flow rate (Q_t), matrix flow rate (Q_m) and fracture flow rate (Q_f):

$$Q_t = n_f Q_f + Q_m \tag{4}$$

Replacing the flow rates from the Darcy equation:

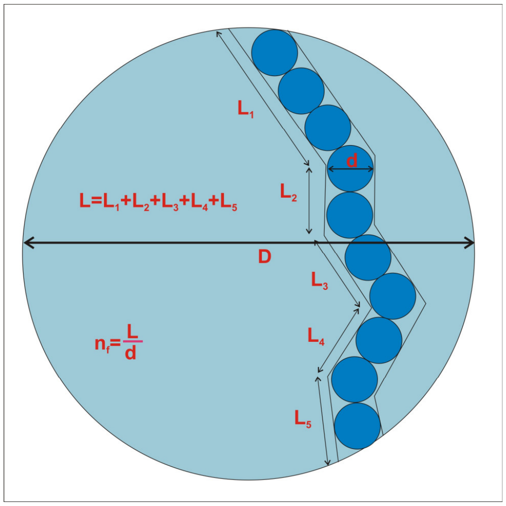

Figure 1. Schematic of the Fracture and Matrix Network in the Conceptual Model

$$-\frac{\pi}{4}D^2\frac{k_t}{\mu}\frac{\partial p}{\partial l} = -n_f\frac{\pi}{4}d^2\frac{k_f}{\mu}\frac{\partial p}{\partial l} - \frac{\pi}{4}(D^2 - n_f d^2)\frac{k_m}{\mu}\frac{\partial p}{\partial l} \tag{5}$$

in which k_t , k_f and k_m are total, fracture and matrix permeabilities. For flow in a dual-porosity medium, Equation (5) holds when the system is not far from equilibrium. The system reaches equilibrium as soon as the injection ceases. Equation (5) can then be simplified to:

$$k_t = n_f \alpha k_f + (1 - n_f \alpha) k_m \tag{6}$$

in which α is $(\frac{d}{D})^2$.

Flow rate of a polymer solution with viscosity μ and the power law constitutive equation parameter n in a capillary tube with radius r and length l are correlated to the pressure drop according to Equation (7).

$$Q = -\frac{n}{2(3n+1)}\frac{\pi R^4}{\mu}\frac{\partial p}{\partial l} \tag{7}$$

Assuming that the fracture consists of n_f capillary tubes, and comparing Equation (7) with Darcy´s law, Equation (8) holds for a capillary tube containing a polymer solution.

$$k_{fp} = \frac{nd^2}{8(3n+1)} \tag{8}$$

The assumption to treat a 2-dimensional (actually, 3-dimensional) fracture with a series of one-dimensional tubes is true only when the fracture thickness does not exceed a certain amount. As water is acting as a Newtonian fluid, the power law constitutive equation parameter is equal to one. So, for the case of a fracture containing water. Equation (8) simplifies to:

$$k_{fw} = \frac{d^2}{32} \tag{9}$$

Writing Equation (6) for water and polymer solutions separately and replacing the permeability for water and polymer solutions in a fracture from Equations (8) and (9), one has:

$$k_{tw} = \frac{n_f \alpha d^2}{32} + \left(1 - n_f \alpha\right) k_{mw} \tag{10}$$

$$k_{tp} = \frac{n_f \alpha n d^2}{8(3n+1)} + \left(1 - n_f \alpha\right) k_{mp} \tag{11}$$

Equating Equation (10) to Equation (11) while multiplying by the ratio of polymer solution viscosity to water viscosity, which is called relative viscosity,, η_{rel} gives the following correlation for the residual resistance factor:

$$RRF = \frac{\dfrac{n_f \alpha d^2}{32} + \left(1 - n_f \alpha\right) k_{mw}}{\dfrac{n_f \alpha n d^2}{8(3n+1)} + \left(1 - n_f \alpha\right) k_{mp}} \eta_{rel} \tag{12}$$

Rewriting Equation (12) for relative viscosity yields

$$\eta_{rel} = \frac{\dfrac{n_f \alpha n d^2}{8(3n+1)} + \left(1 - n_f \alpha\right) k_{mp}}{\dfrac{n_f \alpha d^2}{32} + \left(1 - n_f \alpha\right) k_{mw}} RRF \tag{13}$$

Taking the derivative of the natural logarithm of Equation (13), while taking into account the definition of intrinsic viscosity, leads us to

$$\left.\frac{\partial \ln RRF}{\partial c}\right|_{c \to 0} = \left. [\eta] - \frac{\partial}{\partial c} \ln \frac{\dfrac{n_f \alpha n d^2}{8(3n+1)} + \left(1 - n_f \alpha\right) k_{mp}}{\dfrac{n_f \alpha d^2}{32} + \left(1 - n_f \alpha\right) k_{mw}} \right|_{c \to 0} \tag{14}$$

Integrating Equation (14) with respect to polymer concentration, the residual resistance factor as an exponential function becomes

$$RRF = \exp\left([\eta] c - \ln \frac{\dfrac{n_f \alpha n_c d^2}{8(3n_c+1)} + \left(1 - n_f \alpha\right) k_{mp}}{\dfrac{n_f \alpha d^2}{32} + \left(1 - n_f \alpha\right) k_{mw}} \right) \tag{15}$$

If matrix does not play any role in the flow, it can be assumed that the number of capillary tubes, n_f , and the coefficient, α , are equal to one. Then, Equation (15) becomes

$$RRF = \exp\left([\eta] c - \ln \frac{4 n_c}{3 n_c + 1} \right) \tag{16}$$

And, if the ratio of fracture opening to matrix/plug diameter, α, is negligible, then

$$RRF = \exp\left([\eta] c - \ln \frac{k_{mp}}{k_{mw}} \right) \tag{17}$$

Experimental Polymers

Similar to the previous study by the authors for the experiments on the micro-models, six well-characterized polyacrylamides with different molecular weights and sulfination levels were used here. The specifications of these polymers are listed in Table 1.

Table 1. Specifications of the Polymers used in the Core-Flood Experiments

No	Name	Mw.10^{-6} (Dalton)	Sulfonation (%)	Hydrolization(%)
1	PAAM 30	30	0	0
2	HPAAM 20	20	0	0-25
3	HPAAM 8	8	0	0-25
4	PAAMS 832	8	32	0
5	PAAMS 825	8	25	0
6	PAAMS 65	6	5	0

The desired salinity of the solutions was adjusted using NaCl with a purity of at least 99.5%. The water used was double distilled with an all-glass apparatus. Polymer solutions with the required concentrations were prepared by slowly dissolving the polymer in the distilled water. To avoid any aging effect, the solutions were gently stirred on a mechanical shaker for about 24 hours.

Crude Oil

The surface oil sample of the S-Field which was taken at the well head and used for polymer flooding in micromodels was also used for core-flood experiments. This is relatively light crude with an API gravity of 31.2.

Apparatus

Rotational viscometer

The variation of shear stress of the polymer solution with polymer concentration and shear rate were evaluated with the Physica MCR 301 rheometer.

Capillary Viscometer

Dilute solution viscosity measurements were made using an Ostwald-type viscometer, size 250, manufactured by Petrotest. The viscometer was mounted vertically in a thermostatic bath at appropriate temperatures controlled with a precision of 0.1ºC. The flow times were recorded with a stopwatch capable of registering the time with a precision of 0.1s. Each test was consecutively repeated at least three times and the average of three flow times was recorded.

Sample Acquisitions and Cores

A suitable core plug was used for these experiments. This core plug was from a wellbore of an offshore field with the reservoir conditions listed in Table 2.

Table 2. Plug Descriptions

No.	Depth (m)	KL (mD)	Grain Density (g/cc)	Porosity (%)	Plug Description
6	2930.7	127.969	2.717	3.003	Fractured, Limestone

The offshore fields are the best candidates for polymer injection due to the fact that the essential ingredient of polymer solutions is water. The core-flood experiments were conducted at the reservoir's temperature and pressure. The plug was first cleaned and prepared for primary saturation with a brine of the reservoir's salinity. Then, it was flooded with the oil sampled from the same reservoir to simulate the oil migration process after which it was flooded with brine of a salinity close to sea water. This step represents the water flooding process prior to polymer injection as the field of interest was water flooded. This was followed by a slug of 0.3 pore volume and 700ppm polymer solution and the subsequent brine injection until almost no more oil could be attained. During all flow experiments, the RRF values were recorded by measuring the initial water mobility to the water solution mobility after polymer flooding.

Results and Discussions

The power law constitutive equation parameter was determined using the slope of plotting the logarithm of shear stress as a function of logarithm of shear rate. The calculated power law constitutive equation parameters, for all polymers at 700ppm polymer concentration but at the temperature and salt content of the reservoir, are presented in Table 3.

Table 3. Core-Floods Experimental Conditions

Overburden Pressure (psi)	Pore Pressure (psi)
9500	3500
Temperature (C)	Res. Salinity (ppm)
109	154400
Sea water Salinity	Average depth (m)
41542	28848
Oil Density (g/cc)	Water Injection rate (cc)
0.897101	1.2

To calculate the resistance factor at temperatures and salinities of the reservoir, the intrinsic viscosity had to be estimated under those conditions. As it was not possible to measure intrinsic viscosity at 109ºC, hydrodynamic diameter of polymers at temperatures and salinities of the reservoir had to be estimated from Equation (18). Assuming that the polymers are spherical, and with the help of Equation (19), the intrinsic viscosity for polymer solutions could be calculated for reservoir conditions of

$$\begin{aligned} LnD = (&-2.39*10^{-2}*C_{Salt} \\ &-2.6*10^{-4}*T+5.06*10^{-3}C_{Sulf.} \\ &+3.40*10^{-2}*M_w-15.0939) \end{aligned} \tag{18}$$

where M_w is molecular weight, T is temperature, C_{Salt} is salt concentration, and $C_{Sulf.}$ is sulfonation content of the polymer, such that

$$[\eta] = \frac{\pi.N.D^3}{6M_w} \tag{19}$$

where N is the Avogadro constant and D is the hydraulic diameter of polymer molecules in meters. Using glass micro-models and the simplified analytical solution, it was previously shown that the recovery factor is logarithmically proportional to the resistance factor [1]. The calculated intrinsic viscosities can be found in Table 4.

Table 4. Estimated Polymer Viscosities

Polymer	Estimated Diameter of Polymer (m)	Estimated Intrinsic Viscosity (dL/g)
PAAM 30	4.6546E-07	10.59
HPAAM 20	3.31301E-07	5.73
HPAAM 8	2.20308E-07	4.21
PAAMS 832	2.59031E-07	6.85
PAAMS 825	2.50016E-07	6.16
PAAMS 65	2.59031E-07	9.13

Thin sections of the core plugs were used for the estimation of α defined for Equation (6). Figure 2 illustrates a fracture opening in plug 6. After analyzing the thin sections, an average opening of 53 micrometers was assumed for plug 6.

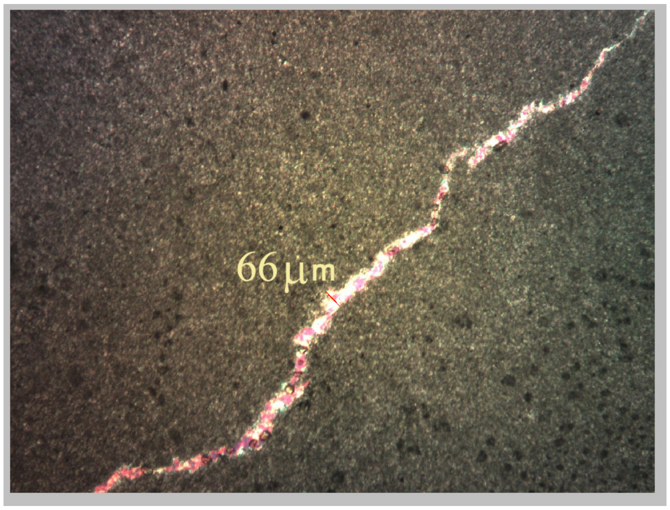

Figure 2. Fracture Opening in Plug 6

The analysis further showed a fracture width of 0.00762m for the plug 6. So, n_f was calculated to be 144 for this case. From Equations (10) and (11), relative matrix permeabilities can be calculated for the water and polymer solutions, the result of which is shown in Tables 5 and 6. The last two columns show the calculation errors for these cases. Clearly, the error is reduced dramatically when both the fracture and matrix contributions are taken into account.

Table 5. Estimated Polymer Viscosities (1)

Polymer	Cal. RRF (Fr.+Mat.)	Cal. RRF)Fr.)	Measured RRF	Er (%) (Fr.+Mat)	Er (%) (Fr.)
HPAAM 20	2.21	1.54	2.46	10.37	37.43
HPAAM 8	1.42	1.36	1.44	1.06	5.26
PAAMS 832	2.08	1.66	2.21	6.02	24.87
PAAMS 825	1.80	1.58	1.86	3.35	15.19
PAAMS 65	1.26	1.44	1.22	-2.99	-17.67
PAAM 30	4.25	2.20	5.48	22.40	59.88

Table 6. Estimated Polymer Viscosities (2)

Polymer	nc	Ktw (mD)	Ktp	Kmw	Kmp
HPAAM 20	0.89	127.97	86.23	103.25	62.59
HPAAM 8	0.94	127.97	120.41	103.25	96.38
PAAMS 832	0.90	127.97	99.17	103.25	75.44
PAAMS 825	0.91	127.97	109.36	103.25	85.53
PAAMS 65	0.94	127.97	123.41	103.25	119.43
PAAM 30	0.84	127.97	62.88	103.25	39.56

Conclusions

In accordance with the theoretical and experimental studies, an analytical relationship—to calculate RRF in fractured medium considering the impact of both matrix and fracture—was developed, which correlates RRF with the coil overlap parameter and water and polymer solution permeabilities in matrix for the case of small fractures relative to matrix size (see Equation (17)). The RRF estimation error dropped significantly, on the order of 3 to 5 fold; refer to Tables (5) and (6).

The experimental results presented here are in agreement with results of polymer flooding in micro-model experiments, confirming that ultimate oil recovery in the polymer flooding process increases as RRF increases. Flow in a dual-porosity system can be routinely treated by the continuum methodology such as the double-permeability or dual-porosity approaches or the discrete fracture network (DFN) models with permeable walls (porous matrix), but the approach presented here simplifies the technique significantly, while not sacrificing results.

Nomenclature

RRF = residual resistance factor
RF = resistance factor
HPAM & PHPA = Partially Hydrolyzed Polyacrylamide
DFN = discrete fracture network
K_w = relative permeability of water
K_p = relative permeability of polymer solution
μ_w = water viscosity
μ_p = polymer solution viscosity
n_c = power law constitutive equation parameter
D = core plug diameter, hydraulic diameter of polymer molecule in meters
L = fracture length
d = fracture opening
Q_m = matrix flow rate
Q_f = fracture flow rate
Q_t = total low rate
k_t = total permeability
k_f = fracture permeability
k_m = matrix permeability
η_{rel} = relative viscosity
M_w = molecular weight
T = temperature
C_{Salt} = salt concentration
$C_{Sulf.}$ = sulfonation content of polymer
N = Avogadro constant

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