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Modeling dynamic fracture growth induced by non-Newtonian polymer injection

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ABSTRACT

Injection of viscous polymer solutions can lead to excessive wellbore pressure and dynamic fracture growth near wellbore which hence increases polymer injectivity. Polymer rheology can also play an important role in affecting the fracture growth due to the dramatic variation of fluid velocity. However, current reservoir simulations for chemical flooding generally overlook the induced fracture, which may lead to inaccurate modeling of polymer floods. In this paper, we developed a new polymer-injection-induced fracture model based on the GdK fracture model, and implicitly coupled it to a general-purpose chemical flood simulator. Mathematical description of the fracture mechanics is presented with consideration of different polymer rheology. The new model is used to simulate polymer floods in a five-spot field. The fracture growth predicted by the new model is verified against a semi-analytical numerical fracture model. The simulation results using the new model indicate that the fracture growth has positive effects on improving injectivity, pressure drop, oil recovery, etc. Also, the simulations illustrate for the first time how polymer rheology affects fracture growth during polymer injection, e.g., without consideration of polymer shear-thickening can postpone the prediction of fracture initiation. The simulations successfully explain why polymer can be economically injected in real polymer fields. The new simulator can be used to optimize polymer floods concerning polymer injectivity, impact of fracture growth on sweeping efficiency, flow out of zone, and others.

1. Introduction

Polymer is a mobility-control agent for chemical flooding processes such as polymer flooding, surfactant/polymer flooding, alkaline/surfactant/polymer flooding, low salinity polymer flooding, etc. (Lake, 1989; Sorbie, 1991; Li et al., 2014; Seright, ,2016; Luo et al., 2016a; Qi et al., 2016; Khorsandi et al., 2016). In field applications, partially hydrolyzed polyacrylamide (HPAM) is widely used for enhanced oil recovery (EOR) and has achieved considerable successes (Chang, 1978). Laboratory corefloods show that HPAM solution behaves Newtonian/shear-thinning at low flow velocities and shear-thickening after flow velocity increases above a critical onset value (Delshad et al., 2008). For polymer flooding, an important concern is the capability of maintaining economic polymer injection rates. At designed injection rate of HPAM solution, flow velocity can easily reach beyond the critical onset velocity for shear-thickening behavior in the near-wellbore region, which means a drastic increase in the apparent viscosity of polymer solution (Li and Delshad, 2014). The onset of shear-thickening behavior would thus lead to excessive wellbore pressure or severe mechanical degradation of polymer molecular. However several field observations indicate good polymer injectivities and acceptable levels of polymer mechanical degradation (Kumar et al., 2012; Manichand et al., 2013). To explain the contradiction between field observations and predictions based on laboratory measurements, this paper investigates the effect of dynamic fracture growth at the injection well assuming in-situ polymer rheology is measured correctly in lab coreflood experiments. Polymer mechanical degradation was neglected in this study and requires further consideration for improving the accuracy of injectivity prediction (Dupas et al., 2013).

When HPAM solution is injected at a fixed rate, wellbore pressure may increase above the rock parting pressure at which fracture initiates. The creation of a fracture at the injection well causes the contact area, where polymer solutions entering a formation from the wellbore to increase by several folds. This greatly decreases the flow velocity near wellbore and also shifts the rheology region from shear-thickening to shear-thinning/Newtonian. During polymer injection processes, dynamic fracture growth helps to maintain the injectivity as the front of polymer solutions propagates in the reservoir (Seright et al., 2009; Khodaverdian et al., 2010; Lee et al., 2011; Suri et al., 2011, 2009;

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Nomenclature

A_{P1}, A_{p2}, A_{p3} polymer viscosity coefficients (dimensionless)
AP_{11}, AP_{22} coefficients in the unified viscosity model (dimensionless)
A_{pe} poro-elastic constant (dimensionless)
a_1, a_2, a_3, b_1, b_2 parameters in generalized power law model (dimensionless)
C shear rate coefficient (dimensionless)
C_p polymer concentration (wt%)
C_{SEP} effective salinity for polymer (meq/l)
C_{Turb} correction coefficient for turbulent effect (dimensionless)
c_m compressibility of rock matrix (psi^{-1})
c_r compressibility of porous media (psi^{-1})
E Young's modulus (psi, Pa)
h_f fracture height (ft, m)
K power law coefficient (cp s^{n-1}, Pa s^{n-1})
K_{IC} critical stress-intensity factor (psi ft$^{1/2}$, Pa s^{n-1})
$\bar{k}$ average permeability (md, m^2)
k_f fracture permeability (md, m^2)
k_x reservoir permeability in x-direction (md, m^2)
k_y reservoir permeability in y-direction (md, m^2)
k_z reservoir permeability in x-direction (md, m^2)
k'_x modified permeability in x-direction in fully penetrated blocks (md, m^2)
k'_z modified permeability in x-direction in fully penetrated blocks (md, m^2)
k'_x modified permeability in x-direction in partially penetrated blocks (md, m^2)
k'_z modified permeability in x-direction in partially penetrated blocks (md, m^2)
k_{rw} relative permeability of aqueous phase (dimensionless)
L_f fracture half length (ft, m)
L_{fp} partial fracture length (ft, m)
n power law exponent (dimensionless)
n_1, n_2 parameters in the unified viscosity model (dimensionless)
P_α parameter in Meter's equation (dimensionless)
p_f fracture fluid pressure (psi, Pa)
p_{fi} fracture initiation pressure (psi, Pa)
p_{foc} fracture opening/closing pressure (psi, Pa)
p_{foc} fracture opening/closing pressure (psi, Pa)
p_{wf} wellbore pressure (psi, Pa)
q_{inj} fluid injection rate (bbl/d, m^3/s)
S_P slope parameter for polymer viscosity vs. salinity and hardness (dimensionless)
S_w saturation of aqueous phase (fraction)
$\vec{u}_w$ Darcy flux of aqueous phase (ft/d, cm/s)
w_f fracture width (ft, m)
$\bar{w}_f$ average fracture width (ft, m)
x_f distance from wellbore to an arbitrary location along a fracture wing (ft, m)
α_B Biot's constant (dimensionless)
$\dot{\gamma}$ shear rate (s^{-1})
$\dot{\gamma}_{\frac{1}{2}}$ parameter in Meter's equation (s^{-1})
γ_c converted shear rate coefficient (dimensionless)
$\dot{\gamma}_{eff}$ effective shear rate or apparent shear rate (s^{-1})
Δp change of reservoir pressure (psi, Pa)
Δp_{fmax} maximum pressure drop within fracture (psi, Pa)
Δx reservoir block size in x direction (ft, m)
Δy reservoir block size in y direction (ft, m)
Δz reservoir block size in z direction (ft, m)
λ parameter in the Careau model (sec)
λ_1, λ_2 parameters in the unified viscosity model (s and dimensionless respectively)
μ viscosity (cp, Pa s)
μ_{app} apparent viscosity (cp, Pa s)
μ_{el} shear-thickening or elongational part of apparent viscosity (cp, Pa s)
μ_{max} maximum viscosity during shear thickening (cp, Pa s)
μ_{sh} shear-thinning part of apparent viscosity (cp, Pa s)
μ_b brine viscosity (cp, Pa s)
μ_p^0 viscosity at very low shear rate (cp, Pa s)
μ_∞ viscosity at infinite shear rate (cp, Pa s)
ν Poisson's ratio (dimensionless)
σ_H maximum horizontal stress (psi, Pa)
σ_{Hi} initial maximum horizontal stress (psi, Pa)
σ_h minimum horizontal stress (psi, Pa)
σ_{hi} initial minimum horizontal stress (psi, Pa)
σ_t tensile strength of reservoir rock (psi, Pa)
τ parameters in the unified viscosity model (s)
ϕ porosity (fraction)

Zechner et al., 2014). The performance of polymer flooding is also affected by the impacts of fracture orientation and length on sweep efficiency (Lee, 2012; Abedi and Kharrat, 2016). Although there is no doubt of the growth of dynamic fractures in polymer flooded fields, the relevant model is generally missing in reservoir simulations. Therefore, it is desirable to develop a polymer injection induced fracture model coupled to EOR simulations.

Research on modeling dynamic fracture has been mostly focused on applications in modeling hydraulic fracturing processes (Adachi et al., 2007; Secchi and Schrefler, 2012; McClure et al., 2016). In those studies, numerous researchers investigated problems such as coupling flow and geomechanical effects (Ganis et al., 2013; Wick et al., 2015), permeability damage (Longoria et al., 2015; Liang et al., 2016; Bao et al., 2016), hydraulic fracture development in unconventional reservoirs (Olson and Wu, 2012; Gu and Mohanty, 2014), the interaction of fracture with fundamental phenomena (Huo and Gong, 2010; Huo et al., 2014), etc.

While many conventional dynamic hydraulic fracture models relate fracture propagation rate with injection rate and leak-off rate (Settari, 1980; Nghiem et al., 1984), they may not be applicable for polymer flooding problems because of large injection/leak-off rate and small fracture volume (Ji et al., 2004). Two popular 2D fracture models that can be good candidates for modeling polymer induced fractures are PKN models (Perkins and Kern, 1961; Nordgren, 1972; Sharma et al., 2016) and GdK models (Khristianovich and Zheltov, 1955; Geertsma and de Klerk, 1969). These two models differ from each other in one basic assumption that the PKN model assumes plain strain in vertical directions while the GdK model assumes plain strain in horizontal directions. Due to this difference, the two models are incompatible but complementary to each other. The PKN model is a good approximation when the ratio of fracture length to height is large while the GdK model is good when the ratio is small. Another potential candidate for modeling dynamic fracture growth with large polymer injection/leak-off rate is the 3D cohesive zone based arbitrary fracture model (Bhardwaj et al., 2016). This 3D fracture model accounts for effects of multiphase flow, poro-thermo-elasticity at the reservoir scale, dynamic filtration, etc. In our study, we use the GdK model, which is suitable for modeling fracture initiation and short fractures, as our basis to model the dynamic fracture growth coupled