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Dynamic modelling of injectivity evolution in unconsolidated sands

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ABSTRACT

Fluid injection into unconsolidated formations serves many different purposes in the oil and gas industry. EOR projects require fluid injection at sustained high flow rates into the reservoir for years. Depending on the matrix properties and injection conditions, individual grains may be detached from the sand matrix and carried away by the fluid. During well shut-ins, pressure transients are generated and the direction of the flow is reversed allowing the grains to be transported and deposited near and even inside the wellbore. The deposited grains may plug the pores around the wellbore and decrease the injectivity, a phenomenon often observed at injection wells targeting unconsolidated formations. In order to address this issue, we implement a model consisting of partial differential equations solved through the numerical finite element methods that decomposes the porosity into mobile and immobile solid phases plus the liquid phase. The mass exchange from mobile to immobile solid phases is dependent on the deposition and erosion rates that are a function of the pressure gradient and stress concentrations around the wellbore. The system uses appropriate scales in size and time as well as appropriate field parameters. The results show how the porosity evolves over time around a hypothetical wellbore; the erosion reduces the pressure gradient until the erosion is negligible. The injection rate, the initial porosity heterogeneity and inter-grain forces (degree of consolidation) proved to have a significant impact on the matrix erosion. Simulations that emulate the effect having gravel and frac-packs were also performed evidencing that the different completion systems help to reduce the formation of high porosity channels around the wellbore during fluid injection.

1. Introduction

A problem often perceived at injection wells is the loss of injectivity (the ratio of the injection rate and pressure). A loss of injectivity implies that either the flow rate is decreased so that the injection pressure is not altered or the injection pressure is increased to meet the required injection rate. In regions like offshore Gulf of Mexico (GOM), drastic injectivity variations take place after wells are shut and restarted. It has been observed that during shut-ins, sand grains flowback into the well which leads to one of the most common reasons for injectivity loss in unconsolidated formations, fluid induced stresses can break the rock apart if its mechanical limits are reached (like hydraulic fracturing), however, in poorly consolidated porous media, it is more likely to have individual particles loosen from the matrix. These sand grains can be easily transported through the matrix in the direction of the flow. When a well is shut, the flow direction oscillates as a consequence of pressure transients and sand may flow towards the well. The consequence of fractures in solid rocks and grain erosion in poorly consolidated sands may be similar in some cases as both leave behind paths of high permeability, however, their mechanisms and hence its geometrical properties may vary significantly as the physical phenomena driving them are completely different.

Experimental studies have shown the existence of different flow regimes in unconsolidated porous media (Golovin et al., 2011; Huang et al., 2011). The results of such revealed that grains will be displaced depending on the fluid and formation properties. Variations on the injection pattern were also shown to rely on the injection conditions and a full understanding of the physical phenomena is required to improve the performance of fluid injection operations. Considering the above-mentioned scenarios, long-held assumptions like Darcy flow or homogeneity and symmetry of flow paths are not really acceptable, hence a need for models that can accurately describe the fluid and formation behavior at the reservoir scale arises. To achieve this, a model based on multiphase volume fraction concept that decomposes porosity to mobile and immobile solid phases that change spatially and evolve over time developing erosional channels is implemented as done by previous authors (Mahadevan et al., 2012; Ameen and Dahi Taleghani, 2014; Gravanis et al., 2015). The model accounts for both particles being released and deposited. Sensitivity studies on the effect of failure criteria for unconsolidated sand, flow rates, cohesion and permeability are in line with experimental observations (Mahadevan et al., 2012). Injectivity depends on interstitial velocity of the injected

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Nomenclature

c_f	formation compressibility
c_t	total compressibility
c_w	water compressibility
d	deposition rate
e	erosion rate
g	gravity
h	payzone thickness
k	permeability
k_x	permeability in x direction
k_y	permeability in y direction
$\mathbf{k}$	principal permeabilities matrix
k_d	erosion rate coefficient
k_e	erosion rate coefficient
l_g	grain diameter
m	horner plot slope for pressure drawdown
q_0	specific discharge
r_w	wellbore radius
r_e	reservoir radius
r	"radius" or distance from the wellbore
s	formation damage
t	time
t_s	stabilization time
u_l	fluid velocity
u_m	mobile granular phase velocity
z	depth
A	Carman-Kozeny parameter
A_w	area open to flow
C	dimensionless failure stress coefficient
D	hydraulic conductivity
P	pressure
P_{1hr}	wellbore pressure one hour after shut-in
P_{wf}	wellbore pressure right before shut-in
$\bar{Q}$	volumetric flowrate
ϕ	porosity
ϕ_{eq}	porosity from erosion in a perfectly homogeneous formation
ϕ_l	liquid volumetric fraction
ϕ_m	mobile grain volumetric fraction
ϕ_s	immobile grain volumetric fraction
ϕ_s^*	deposition threshold
$\bar{\phi}_s$	average immobile grain volumetric fraction
γ	characteristic fluid velocity to hydraulic conductivity ratio
μ	fluid viscosity
ρ	fluid density
σ	failure stress
ψ	sphericity

fluid which is related to injection rate, injection temperature, porosity distribution, volume concentration of solids, size of proppants (if any), completion systems, and in-situ stresses. Any alteration of these parameters might have an effect on injectivity. Some other causes for injectivity variations are; suspended particles in the injected fluid which may deposit and plug the pores of the matrix, solids precipitation that form from incompatibilities between the injected mixture and formation fluids, fines migration, and the swelling of clay minerals. Regardless of the case, the reduction of permeability near the wellbore region requires an increment injection pressure in order to meet a desired injection rate. As the pumping pressure is increased, the pressure gradient and the forces acting on individual grains rises and may eventually lead to erosion. Eroded grains are easily transported by the injected fluids creating 'fracture-like' channels of enhanced permeability, the process that we refer to as channelization.

If the changes undergone by an unconsolidated formation during fluid injection can be accurately quantified, improvements to design and placement of frac and gravel packs and the aerial sweep efficiency for EOR projects can be more accurately predicted.

Fig. 1 shows the injectivity behavior of well A09 located in the GOM for a period of 400 days (Sharma et al., 2000). The well is a water injector completed with a gravel pack targeting a sand formation. It is important to realize that the injection pressure is relatively constant (3000 psig) meaning that any change in injectivity will be evidenced on the injection rate curve. Initially, well A09 has an injection rate of about 1,500BWPD that reaches 7000BWPD after an acidization treatment. Although the stimulation had a positive effect, it fades away fast and after approximately100 days, the injection rate is down to the initial level. In general, injection rates for well A09 are low when compared to wells in a different offshore development at which rates of up to 50,000BWPD have been reported (Svendson et al., 1991, and more on economic impacts in Dahitaleghani and Tyagi (2015)). Many modelling and simulation efforts related to injectivity variations have been performed, however, channelization has not been addressed yet and sometimes fracture mechanics of brittle materials is used to predict the creation of channels.

Experiments conducted by Bohloli and De Pater (2006), have consistently reported higher net fracturing pressures in soft and plastic materials. Moreover, the net fracturing pressures increase with decreasing fluid efficiency because, unlike very high stress concentrations which develop at the crack tip in a brittle linearly elastic material, the stress concentrations at the crack tip in a plastic material are much lower due to ductile yielding at the tip, which relieves and redistributes the high stresses in the vicinity of the tip. The plastic yielding at the crack tip effectively shields the crack from the influence of pressures acting at its faces (Papanastasiou, 1999; Dong and De Pater, 2008). Therefore, higher net fracturing pressures are required to obtain high enough stress concentrations at the tip to further crack the formation by tensile failure. Huang et al. (2011) studied different flow patterns for fluid injection at surface conditions. A series of injection experiments were conducted in a Hele-Shaw cell in a dry dense granular medium invaded by an aqueous glycerin solution. Variations of the fluid viscosity, the normalized injection velocity and the flow rate allowed the authors to observe four different flow regimes: 1) a simple radial flow regime, 2) an infiltration-dominated regime, 3) a grain displacement-dominated regime, and 4) a viscous fingering-dominated regime.

Mahadevan et al. (2012) built an experimental setup for flow-induced erosional channelization in a saturated, granular porous

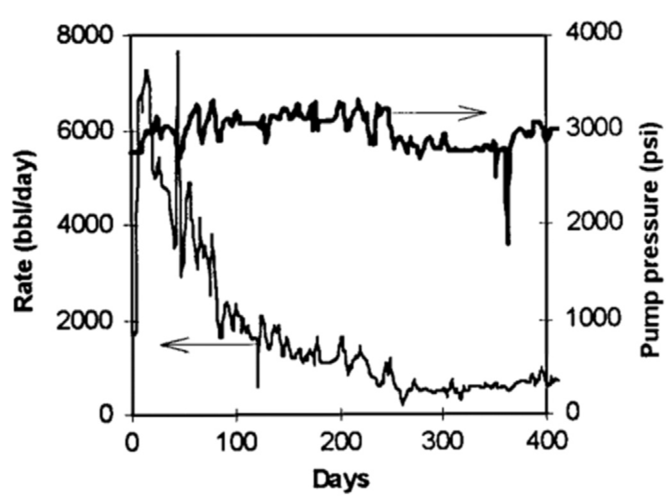

Fig. 1. Injection decline for a well in unconsolidated formation located in the Gulf of Mexico (After Wennberg and Sharma (1997)).