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Slip-corrected liquid permeability and its effect on hydraulic fracturing and fluid loss in shale

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HIGHLIGHTS

- We introduce the concept of liquid slip flow in shale.
- We present a stochastic model to determine slip-corrected permeability.
- Slip corrected permeability is much greater than intrinsic permeability.
- Liquid slip affects induced facture network.
- Liquid slip is a possible explanation of the high level of fluid loss in shale.

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ABSTRACT

Pore diameter in shale strata ranges from a few to hundreds of nanometers, whereas in conventional reservoirs the range is 3 orders of magnitude greater. In spite of the small size of the pores—which would be expected to cause very low intrinsic permeability—field reports document unusually high loss of hydraulic fracturing fluid (as much as 90%) in shale reservoirs. The lost fluid remains in induced fractures and also leaks off into the shale matrix. Liquid flow in tiny pores is different from the flow in large pores. To compensate for this difference, the traditional liquid flow model needs a correction parameter called *liquid slip length*. We measured slip length of brine and pores in shale by using an atomic force microscope (AFM). Our measurements suggest a slip length of 250 nm in organic pores. We used measured slip length in a stochastic permeability model to calculate apparent liquid permeability (ALP) in the shale matrix. When corrected for slip length, the ALP in shale can be much greater than intrinsic Darcy permeability. We then used ALP in a coupled flow–geomechanical simulator to study the effects of slip-corrected matrix permeability on the induced fracture network and fluid loss during hydraulic fracturing. The results show the dramatic effects of the slip parameter on the fracture network and explain the high fluid loss during hydraulic fracturing.

1. Introduction

Hydraulic fracturing is needed to stimulate ultratight shale gas reservoirs to make gas production economically feasible. Hydraulic fracturing fluid is composed of water, chemical additives, and proppants (sand grains). The fracturing fluid is injected into a packed-off section of a horizontal wellbore to build up pressure; once pressure exceeds formation strength, the rock around the wellbore breaks and a fracture or network of fractures is created. These induced fractures kept open by the proppant material act as conduits (highways) for hydrocarbon molecules to be transported from the bulk matrix into the wellbore. Ideally, before hydrocarbon production starts and at early production time, as much water as possible must be produced back to the surface, the so called flowback. Fig. 1 illustrates fracture fluid injection, flowback, recycling, and disposal. The usage of water for hydraulic fracturing is small compared with other water usage [1,2], but because the lost water leaves the ecosystem on a local and global scale, any attempt to understand the process and minimize the loss is of great interest. It is therefore desirable to flowback all the injected fluid from the fractures and reuse it for another fracturing job. However, during the fracturing process in shale systems, a good portion of the fracture fluid remains in the formation and cannot be flowed back. The unproduced portion of the injected fluid is known as fluid loss in the industry. Fluid losses of as much

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Nomenclature

Symbols
b slip length (nm)
c_f fluid compressibility (MPa^{-1})
c_ϕ porosity compressibility (MPa^{-1})
e hydraulic aperture (μm)
F force (N)
h separation distance (m)
k permeability (1 nD ~ 10^{-21} m^2)
$k_{i,j}$ local permeability at each grid block (1 nD ~ 10^{-21} m^2)
m mass density (kg m^{-3})
N_x number of grid blocks in x direction
N_y number of grid blocks in y direction
P pressure (MPa)
q_{flux} mass flux (kg s^{-1})
R sphere radius (m)
T transmissivity
v velocity, sliding velocity of the fracture (m s^{-1})

Greek letters
μ viscosity (mPa s)
ρ fluid density (kg m^{-3})
τ shear stress (MPa)
ϕ porosity

Subscripts
init initial

Abbreviations
AFM atomic force microscope
ALP apparent liquid permeability
CDF cumulative distribution function
CFRAC Complex Fracturing ReseArch Code
iOM inorganic material
MICP mercury injection capillary pressure
NMR nuclear magnetic resonance
OM organic matter
PSD patch-size distribution; pore-size distribution
SEM scanning electron microscope
TOC total organic carbon

as 90% have been reported in shale strata [1,2]. Major loss of injected hydraulic fracture fluid in shale raises important technical, economical, and environmental concerns [3,4]. A portion of the lost fluid remains in the induced fracture, and a portion leaks off into the matrix in spite of extremely low intrinsic Darcy permeability. Leaked-off fluid hinders the passage of gas molecules from the matrix to the fractures, diminishing stimulation efficiency.

As confirmed by many researchers, pores in shale are mostly in the range of a few to hundreds of nanometers, comparable to 10—100s layers of liquid molecules [5–9]. Therefore, shale matrix intrinsic permeability is in the nanoDarcy (nD) range. Intuitively it might seem that fracture fluid should not be able to flow in such a tight system. In this paper we address possible reasons why fracture fluid can infiltrate the ultratight shale matrix. We try to shed light on the flow of liquid in nanopores of shale. In such small pores, the assumption of no-slip flow-boundary conditions at the inner pore walls underestimates liquid flow in the shale matrix. We present a detailed description of liquid slip flow in a shale matrix. We then present a methodology to measure the liquid slip coefficient for a shale sample using atomic force microscope (AFM) metrology [8]. Note that the concept of liquid slip [10] is similar to gas slip [7,11–14], but the measuring methodologies, the values, and implementation in flow equations are different. Measured values of slip length are implemented in a modified stochastic permeability model [15] to determine the effective permeability of the shale matrix. Calculated permeability are then used in a coupled

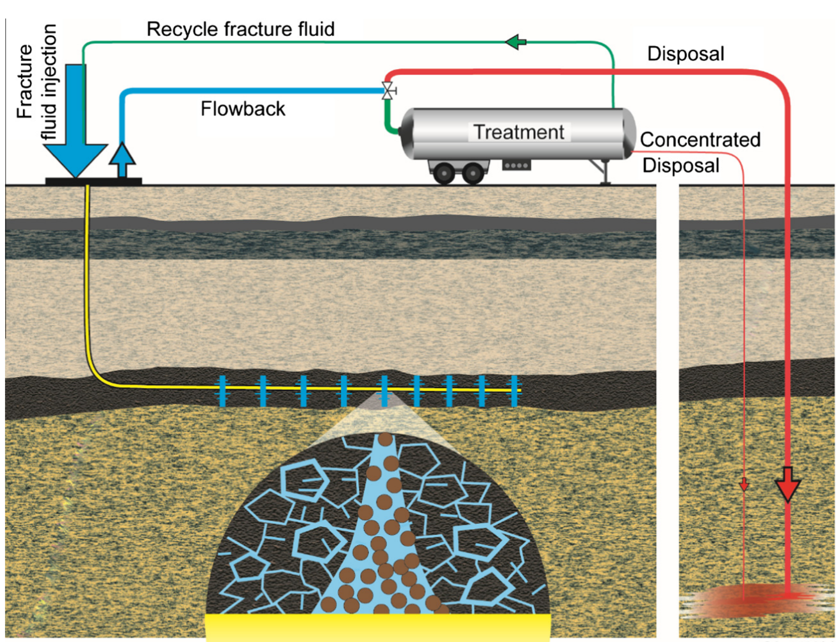

Fig. 1. Schematic illustration of fracture fluid injection, flowback, recycling, and disposal. The usage of water for hydraulic fracturing is small compared with other water usage, but because lost water would be out of the ecosystem, any attempt to understand the process and minimize the loss is of great interest.