Journal of Petroleum Science and Engineering 151 (2017) 264–274

Contents lists available at ScienceDirect

Journal of Petroleum Science and Engineering

journal homepage: www.elsevier.com/locate/petrol

Impact of chemical osmosis on water leakoff and flowback behavior from hydraulically fractured gas shale

Fei Wang*, Ziqing Pan, Shicheng Zhang

China University of Petroleum, Beijing, China

ARTICLE INFO

Keywords:
Shale
Chemical osmosis
Fracturing-fluid
Leakoff
Flowback

ABSTRACT

In this paper, the development of a comprehensive multi-mechanistic multi-porosity water/gas/salt flow model to investigate the leakoff and flowback behavior of the fracturing fluid from hydraulically fractured shale gas wells is presented. The multi-mechanistic model takes into account water transport induced by hydraulic pressure driven convection, osmosis pressure driven convection and capillary imbibition, gas transport induced by both hydraulic pressure driven convection and desorption, and salt transport induced by advection and concentration driven diffusion. In the multi-porosity model, hydraulic fractures are considered as a interconnected continuum embedded in shale matrix, where organic shale is interspersed within vast inorganic shale. The organic matrix is thus considered disconnected in the entire reservoir. The water saturation profiles for chemical osmosis-induced, capillary pressure-induced and hydraulic pressure-induced cases are compared, revealing a region of saturation that effectively is immobile even though irreducible saturation has not been reached. In sensitivity analyses, cases with different hydraulic pressure, injected fluid salinity and salt diffusion coefficient are considered.The results indicate that chemical osmosis intensifies water leakoff and hinders water flowback. Further, chemical osmosis is a key mechanism for water retention after the treatment of hydraulic fracturing and should not be ignored especially in flowback data analysis of hydraulically fractured shale gas wells.

1. Introduction

As an important unconvectional natural gas resource, shale has received much attention. The United States and Canada have successfully commercially exploited many shale basins (Ahmed, 2015). Slickwater fracturing is one of the key technologies for realizing fracturing stimulation in shale gas reservoirs (Thompson et al., 2010). Comparing with crosslinked water-based fracturing-fluids, the slickwater fracturing-fluid has several advantages, including low cost (because the water ratio can be as high as 99.5%), less formation damage and ease of creating complex fracture networks (Schein, 2004; Cipolla et al., 2009; Cheng, 2012). One of the concerns with slickwater is that most of the water pumped during the treatment is retained in the shale reservoir. In practice, it is common that only a small fraction of pumped water, typically 10–20%, can be recovered during the process of flowback for cleanup of the loaded fluid.

In many studies, this water retention phenomenon is attributed to two mechanisms: fracture closure and water leakoff. However, there is no proven explanation of which of the two mechanisms is predominant. Some researchers believe that water trapped in the fracture network might be the major mechanism responsible for water retention. They consider that because of the low permeability of shale matrix, most of the pumped water will remain either in fractures as an immobile "propping" phase or in "non-communicating" fractures that were initiated by the treatment but become disconnected from the well after fracture closing (Fan et al., 2010; Ehlig-Economides and Economides, 2011; Sharma and Agrawal, 2013). Other researchers consider that water leaked into shale matrix might be the major mechanism responsible for water retention (Roychaudhuri et al., 2011; Dehghanpour et al., 2012, 2013; Makhanov et al., 2012; Lan et al., 2014). Besides the forced leakoff driven by pressure difference between hydraulic pressure and formation pore pressure, spontaneous imbibition driven by capillary pressure is a widely reported effect that induce extra water invasion. A vast amount of experimental and mathematical studies have been conducted to investigate the spontaneous imbibition of water into shale matrix. Several single-porosity or dual-porosity gas/water flow models are established to simulate fracturing fluid flowback and analyze fracture parameters (Michel et al., 2012; Jurus et al., 2013; Ilk et al., 2010; Lee and Karpyn, 2012; Ezulike et al., 2013; Clarkson and Kovacs, 2013; Almulhim et al., 2014; Xu et al., 2015). In these

* Corresponding author.
E-mail address: wangfei@cup.edu.cn (F. Wang).

http://dx.doi.org/10.1016/j.petrol.2017.01.018
Received 20 July 2016; Received in revised form 29 December 2016; Accepted 5 January 2017
Available online 06 January 2017
0920-4105/

Nomenclature

B_w	water-phase volume factor, non-dimensional
C^f	salt concentration of fluid in the hydraulic fracture, ppm
C^m	salt concentration of fluid in the matrix, ppm
C^{inj}	salt concentration of the injected fluid, ppm
C_0^f	initial salt concentration of fluid in the hydraulic fracture, ppm
C_0^m	initial salt concentration of fluid in the matrix, ppm
C^{fm}	salt concentration of fluid transferring between the hydraulic fracture and matrix, ppm
D_1	diffusion coefficient of salt ions between the hydraulic fracture and matrix, cm^2/s
D_2	diffusion coefficient of salt ions within the matrix, cm^2/s
f_r	water load recovery of the well, %
h_f	height of the hydraulic fracture, m
H	height of the shale reservoir, m
l_f	half-length of the hydraulic fracture, m
L	length of the shale reservoir, m
k^f	hydraulic fracture permeability, μm^2
k_{rw}	relative permeability of water, non-dimensional
k^m	permeability of the matrix, μm^2
k_{rg}	relative permeability of gas, non-dimensional
m_g	mass of adsorbed gas in formation volume, g/cm^3
p_w^f	water-phase pressure in the hydraulic fracture, bar
p_{wf}	flowing pressure in the bottom hole, bar
p_w^m	water-phase pressure in the matrix, bar
p_g^m	gas-phase pressure in the matrix, bar
p_w^m	water-phase pressure in the matrix, bar
p_g^f	gas-phase pressure in the hydraulic fracture, bar
p_g^m	gas-phase pressure in the matrix, bar
p_{cgw}	capillary pressure in the matrix, bar
p_L	Langmuir's pressure, the pressure at which 50% of the gas is adsorbed, bar
q_g^{fW}	gas-phase transfer rate between the fracture and wellbore, g/cm^3 s
q_g^{mf}	gas-phase transfer rate between the fracture and matrix, g/cm^3 s
q_w^{fW}	water-phase transfer rate between the fracture and wellbore, g/cm^3 s
q_w^{mf}	water-phase transfer rate between the fracture and matrix, g/cm^3 s
$Q_w{}^{W\text{-}f}$	accumulated injection volume of water from the wellbore to fracture, m^3
$Q_w{}^{f\text{-}m}$	accumulated leakoff volume of water from the fracture to matrix, m^3
$Q_w{}^{f\text{-}W}$	accumulated flowback volume of water from the fracture to wellbore, m^3
$Q_w{}^{f\text{-}m}$	accumulated flowback volume of water from the matrix to fracture, m^3
V_w	partial molar volume of water, 10 m^3/kmol
V_E	standard gas volume adsorbed per unit rock mass, cm^3/g
V_L	Langmuir's volume, cm^3/g
w_f	width of the hydraulic fracture, cm
W	width of the shale reservoir, m
R	ideal gas constant, 0.008314 MPa m^3 /(kmol K)
S_w^f	water saturation in the hydraulic fracture, non-dimensional
S_g^f	gas saturation in the hydraulic fracture, non-dimensional
S_w^m	water saturation in the matrix, non-dimensional
S_g^m	gas saturation in the matrix, non-dimensional
S_{w0}^m	initial water saturation in the matrix, non-dimensional
S_{w0}^f	initial water saturation in the hydraulic fracture, non-dimensional
S_k	volume proportion of source rock
T	temperature, K
x_m	molar fraction of water in the matrix, non-dimensional
x_f	molar fraction of water in the hydraulic fracture, non-dimensional
α	shape factor between the hydraulic fracture and matrix, cm^{-2}
δ	shape factor between the wellbore and the hydraulic fracture, cm^{-2}
ρ_w	density of water, g/cm^3
ρ_g	density of gas, g/cm^3
ρ_R	source rock density, g/cm^3
ρ_{gsc}	gas density at standard condition, g/cm^3
η_w	viscosity of water, mPa s
η_g	viscosity of gas, mPa s
ϕ^f	hydraulic fracture porosity, non-dimensional
ϕ^m	matrix porosity, non-dimensional
F_s^{adv}	salt transfer terms between the hydraulic fracture and matrix by advection, 10^{-6} s^{-1}
F_s^{diff}	salt transfer terms between the hydraulic fracture and matrix by diffusion, 10^{-6} s^{-1}
n	normal direction of the outer boundary
Γ	outer boundary of a shale reservoir

models, gas/water relative permeability, formation stress sensitivity, capillary pressure, gravity and other physical factors are considered.

Shale is composed of fine-grained sediments with strong heterogeneity; it mainly contains kerogen, clay, quartz, feldspar and pyrite. Compared with convectional reservoirs, a shale reservoir has a relatively high clay content, reaching up to 80% (Bohacs et al., 2013). High-clay shale formations could behave as a semi-permeable membrane, thus causing osmotic water molecules permeate the membrane and migrate, that is, water molecules migrate from the low-salinity side of the semi-permeable membrane to the high-salinity side (Lomba et al., 2000; Rahman et al., 2005; Al-Bazali et al., 2009; Fakcharoenphol et al., 2014; Wang and Raham, 2015). A shale matrix contains a certain amount of formation water. As a result of the water drainage during the tectonic compaction process (Bredehoeft et al., 1963) and the water consumption during the hydrogen generation process (Schimmelmann et al., 2001; Mastalerz and Schimmelmann, 2002), the original formation water has extremely high salinity (Fang et al., 2014). Haluszczak et al. (2012) showed that the brine salinity of the shale reservoir is high, reaching up to 280000 ppm. Generally, the salinity of slickwater is low, approximately 1000 ppm. Therefore, in a hydraulic fracturing treatment, the significant salinity difference between the injected slickwater and formation brine inevitably results in a considerable chemical potential difference, eventually causing the osmotic migration phenomenon of water molecules.

Despite all previous studies, analyzing leakoff and flowback behaviors of the fracturing fluid driven by various mechanisms, especially chemical osmosis on gas/water/salt flow in shale remains largely unexplored. In this study, a comprehensive multi-mechanistic multi-porosity water/gas/salt flow model is developed. Then, a numerical model is built to accurately simulate and predict water flow behavior in hydraulically fractured gas shale. Sensitivity analyses are performed to further investigate the chemical osmosis, capillarity and hydraulic pressure respectively on the water saturation distribution and migration front progression. The results would help to understand the impact of shale properties on the water leakoff and flowback as well as provide detailed quantitative information for the simulation and prediction of multiphase flow in hydraulically fractured gas shale.