Journal of Unconventional Oil and Gas Resources 11 (2015) 60–74

Contents lists available at ScienceDirect

Journal of Unconventional Oil and Gas Resources

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

Practical insights into liquid loading within hydraulic fractures and potential unconventional gas reservoir optimization strategies

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ARTICLE INFO

Article history:
Received 19 September 2014
Revised 31 January 2015
Accepted 20 April 2015
Available online 8 May 2015

Keywords:
Unconventional
Unloading
Cleanup
Conductivity
Gravity
Hydraulic fractures

ABSTRACT

The U.S. has experienced a resurgence of the upstream hydrocarbon sector in recent years, owing to the economic extraction of oil and gas from ultra-tight reservoirs using multistage hydraulic fracturing in horizontal wells. This success is often attributed to slick-water stimulation treatments that help create extensive complexity and contact with the low permeability reservoir. In this process, hundreds of thousands of barrels of water are pumped downhole, along with friction reducers, low concentration linear gel, fracture propping sand and other additives, to create and sustain these fractures. However, only a small percentage of this stimulation water is recovered back once the well is put back on production. This not only leads to excessive water hauling costs for operators in each consecutive well but also liquid blockage for hydrocarbon flow. Such water blockage/loading may become a serious concern in dry gas reservoirs such as the Marcellus field in the northeastern U.S., due to the unfavorable hydrocarbon mobility ratios. In spite of its implications on early and late time well performance, the issue of hydraulic fracture cleanup and gas flowback through it when drained through a horizontal wellbore is still an insufficiently understood subject. In this study the authors investigate the potential of liquid loading (stimulation water or condensate) within the hydraulic fracture itself due to low matrix permeability and insufficient drawdown conditions. Similar conditions may also arise late in the life of well when the reservoir pressure has declined significantly or due to wellbore design issues. A 3D reservoir simulation model with a discrete, planar hydraulic fracture is set up to investigate the competition between capillary, viscous and gravity forces within the fracture. The results indicate a strong tendency for liquid loading in the ultra-low permeability gas reservoirs under common operational constraints and offer recommendations on best practices to minimize its impact.

Introduction

Water management and its impact on unconventional reservoir economics is a key focus area for the industry these days. Slutz et al. (2012), Fedotov et al. (2013) have highlighted the issues at hand and suggested possible best practices. On an average less than 25% of stimulation water is ever recovered back in most of the contemporary unconventional reservoirs under development (Pagels et al., 2012). Loss of stimulation water can broadly be attributed to three factors: (1) imbibition into the matrix due to high capillary pressures, (2) leakage to un-propped induced fractures and their closure after drawdown or (3) retention within stimulated hydraulic fractures. Various researchers have investigated the impact of stimulation water invasion into the matrix and the resulting fracture treatment performance in conventional reservoirs. It is commonly believed that majority of the stimulation fluid is trapped in the matrix due to capillarity effects. Holditch (1979) highlighted the importance of capillary pressure, matrix permeability damage and relative permeability, in understanding the extent of productivity damage due to fracturing water invasion. He concluded that unless the reservoir rock permeability is significantly damaged by the stimulation fluid, a complete water block to gas flow will not occur and that a large enough drawdown will achieve the same cumulative gas production irrespective of the capillary pressure. Solimon and Hunt (1985) corroborated with these results using a similar 2D cleanup model. Settari et al. (2002) showed the impact of water blocks on well productivity and studied their signatures from pressure transient analysis (PTA) for the Bossier play. Later, Friehauf et al. (2009) developed a flow resistor analytical model for well productivity of hydraulically fractured wells with finite fracture conductivity and invaded zone damage. Gdanski and Walters (2010) simulated various scenarios to study the impact of fracture conductivity, matrix relative

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http://dx.doi.org/10.1016/j.juogr.2015.04.001
2213-3976/

Nomenclature

bbl	barrel of oil	Q	gas rate (MMscf/d)
scf	standard cubic feet	N	No. of hydraulic fractures
ppg	parts per gallon	h	height of stimulated fractures (ft)
mD	milli Darcy	w	thickness of stimulated fractures (ft)
ft	feet	B_g	gas formation volume factor (scf/cf)
lb	pounds	Φ	effective propped fracture porosity
MMscf/day	millions of standard cubic feet of gas per day	σ	surface tension between gas and water (dynes/cm)
k_{frac}	fracture permeability (mD)	ρ_L	density of liquid phase (lb/ft^3)
w_{frac}	fracture width (ft)	ρ_G	density of gas phase (lb/ft^3)
k_{matrix}	matrix permeability (mD)		
X_{frac}	fracture half length (ft)		
V_{crit}	Turner's critical gas velocity		

permeability and flowback conditions on load recovery and gas production. Higher water relative permeability allowed deeper imbibition of water during shut-in period and reduced fracturing water recovery. Shaoul et al. (2011) studied the impact of damage and different relative permeability models on gas production in unconventional reservoirs with similar simulation setup as above and observed up to 50% reduction in early time gas production due to blockage.

However, all of the above referenced works lack a discussion on accumulation and segregation of liquid within a tall vertical fracture itself, which is drained by a horizontal well, due to gravity and its competition with capillary forces as well as drawdown. Conventional fracture cleanup models worked well for vertical wells where lifting stimulation water to perforations was not an issue (primarily horizontal flow). However, in the case of horizontal wellbores with significant vertical flow within fractures to reach horizontal well perforations, a fresh re-examination of existing cleanup models is needed. A recent experimental study by Parmar et al. (2012) has shown significant liquid loading possibility at fracture bottom due to adverse mobility ratio and gravity segregation at low gas flow rates. The results indicate poorer fracture cleanup/water displacement by gas moving against gravity and formation of fingers through the proppant pack. In another experimental study, Palisch et al. (2007) had shown that even a small amount of residual liquid in the proppant pack can significantly increase the pressure drop, compared to a completely clean fracture, implying significant reduction in effective conductivity. This is attributed to multi-phase flow effects. These experimental results can help explain field observations such as the one presented in Taylor et al. (2011). This case study highlighted the improvements in production performance of wells which were placed at the bottom of targeted formations and attributed the improvements to gravity drainage effect that helps to clean the fracture above the wellbore. In order to investigate this process numerically, a commercial reservoir simulator was used in this study, to simulate liquid loading in tall, planar hydraulic fractures, which are drained through a horizontal wellbore. Generally, hydraulic fractures in horizontal wells can grow from tens to hundreds of feet in height. If liquid loading takes place in a certain section of the fracture, it will impair the inflow of gas from that section thereby leading to a reduction in the effective contact area or fracture conductivity as shown by schematic in Fig. 1.

In geomechanically sensitive reservoirs such as the Marcellus or Haynesville, multiple operators employ a surface choke management strategy to control the effective reservoir drawdown and minimize the closure of stimulated fracture network, propped or not. Studies have indicated that in some over-pressured unconventional reservoirs pore volume changes may be as high as 20% due to production induced stress changes (Akande and Spivey, 2012).

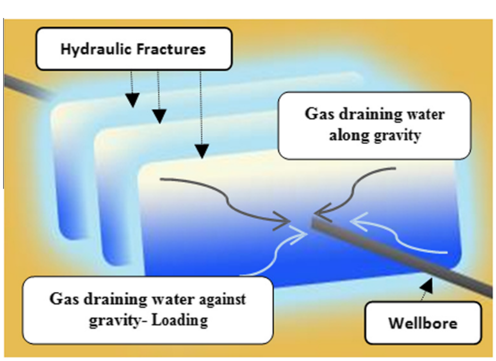

Fig. 1. Schematic showing liquid loading within the fractures.

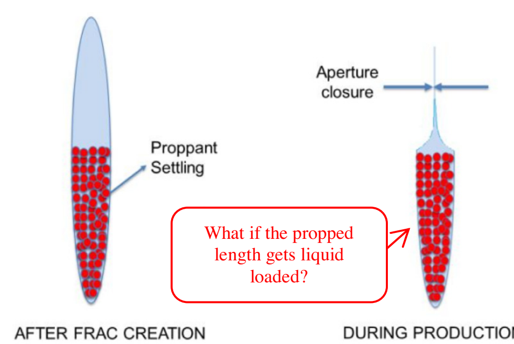

Fig. 2. Impact of proppant settling and fracture closure.

Table 1
Base case black oil model properties.

Description	Value
Matrix permeability	1 μD
Fracture permeability	2 D
Fracture height	55 ft
Fracture thickness	0.01 ft
Fracture half length	175 ft
Gas–water surface tension	40 dyne/cm
Gas gravity	0.6
Water density	14.7 lb/ft^3
Flowing bottom-hole pressure	4500 psi
Initial reservoir pressure	6500 psi
Matrix initial water saturation	0.2
Matrix residual water saturation	0.2