Journal of Natural Gas Science and Engineering 17 (2014) 1–12

Contents lists available at ScienceDirect

Journal of Natural Gas Science and Engineering

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

Investigation of gas flow hindrance due to fracturing fluid leakoff in low permeability sandstones

S.M. Odumabo [a,*], Z.T. Karpyn [b], L.F. Ayala H. [b]

[a] Schlumberger Well Services, USA
[b] John and Willie Leone Family Department of Energy and Mineral Engineering, EMS Energy Institute, The Pennsylvania State University, University Park, PA 16802, USA

ARTICLE INFO

Article history:
Received 19 July 2013
Accepted 13 December 2013
Available online 16 January 2014

Keywords:
Fracturing fluid
Saturation
Permeability
Shut-in time
Fluid leak off
Low permeability formations

ABSTRACT

Hydraulic fracturing has become a necessary practice in order to attain economical gas flow rates from low permeability formations. During and immediately following the creation of a fracture, high injection pressures cause fracturing fluid to leak off into the adjacent matrix. This work focuses on the impact of fracturing fluid leak off on gas flow through tight formations as a function of leakoff volume and shut-in time.

It was observed that an increase in leakoff volume reduces effective permeability to gas while an increase in shut-in time increases it. Gas flow hindrance caused by the leak off of water-based fracturing fluid is mitigated by shut-in time in that it favors spontaneous redistribution of the fluid deeper into the rock matrix. However, results from this work demonstrate that the flow hindrance caused by the initial leak off is superior to the effective permeability gains by shut-in time. This imbalance highlights a key determining factor behind gas flow hindrance due to fracturing fluid leak off – fluid saturation in the neighborhood of the fracture.

The properties of the formation were found to also play a significant role in determining regained permeability. Lower formation permeability slows improvements to gas flow due to lower mobility of the invading fluid despite expected higher capillarity. Furthermore, the extension of these observations to rock formations with lower permeability, such as tight sand and shale, suggests that shut-in time may have an insignificant impact on regained permeability improvement in systems with depressed relative permeability curves.

Leakoff volume and shut-in time are variables that work differently to dictate saturation distribution in the neighborhood of the fracture. Saturation within the invaded zone and characteristics of the formation's relative permeability curve may be the key determinants of gas flow hindrance following hydraulic fracturing activities. This may explain the lack of trends in the field – conditions vary between formations.

1. Introduction

Hydraulic fracturing is a reservoir stimulation method often applied to low permeability formations that would otherwise be uneconomical to produce. Large volumes of a water, proppant and chemical blend are injected into the reservoir rock to create highly conductive fractures that improve the flow of hydrocarbons. Often times, the high pressures used during stimulation operations cause some of the fracturing fluid to leak off into the adjacent matrix. The depth of invasion depends on factors such as properties of the adjacent rock matrix, exposure time to the fracturing fluid, and the fluid volume that leaks off (Friedel, 2004).

The entry and presence of the invading fluid alters the rock matrix in the vicinity of the fracture through different mechanisms. Fracture face damage, relative permeability hysteresis, and water blocking are such damage mechanisms that have been determined to have an appreciable impact on gas production (Bahrami et al., 2011; Bennion and Thomas, 2005; Sherman and Holditch, 1991). Damage to the fracture face is often associated with clay hydration and migration as well as plugging of the pore spaces along the face of the fracture by residue from fracturing fluid additives. A localized reduction in absolute permeability ensues and capillary pressures are magnified (Dehghanpour et al., 2012; Sherman and Holditch,

* Corresponding author. Address: 9931 Hyatt Resort Drive, Apt 927, San Antonio, TX 78251, USA. Tel.: +1 814 441 3221.
E-mail addresses: sodumabo@gmail.com (S.M. Odumabo), ZKarpyn@psu.edu (Z.T. Karpyn), ayala@psu.edu (L.F. Ayala H.).

1875-5100/$ – see front matter © 2014 Elsevier B.V. All rights reserved.
http://dx.doi.org/10.1016/j.jngse.2013.12.002

1991). In fact, Bahrami et al. (2012) found that the presence of the Smectite clay mineral group within a tight formation can significantly compromise the productivity of a hydraulic fracture. In the context of this work, relative permeability hysteresis refers to a reduction in relative permeability to the gas phase as a result of fracturing fluid invasion (Sherman and Holditch, 1991). Water blocks are a manifestation of liquid phase trapping which occurs when capillary forces trap water in the pore spaces of a rock (Bahrami et al., 2011). This mechanism is worsened when fracture face damage is present. In the absence of fracture face damage, it is possible for fluid leak off to have minimal impact on gas production. This can happen if the invading fluid is mobile enough to be imbibed further into the formation or if production drawdown is higher than the capillary forces holding the fluid within the pore spaces (Gdanski et al., 2005). Imbibition of the invading fluid away from the fracture reduces the impact of fluid leak off on gas production by reducing the saturation in the vicinity of the fracture in the absence of permeability damage (Cheng, 2012; Friedel, 2004; Gdanski et al., 2005; Sherman and Holditch, 1991).

During fracturing activities, filtrate invasion causes water saturation in the vicinity of the fracture to increase from an initial saturation to some higher value. The cleanup process and subsequent production cause some of this fluid to be produced back as flowback water and the saturation in the invaded zone decreases to irreducible levels. In tight rocks, however, the final saturation is often greater than the initial saturation prior to leak off. This behavior occurs in water-wet formations i.e. formations with subirreducible initial water saturation. This means that the initial water saturation is less than the irreducible water saturation expected for that formation at that depth (Taylor et al., 2009; Bennion and Thomas, 2005). In such formations, a permanent increase in water saturation is established once leak off occurs. The presence of the additional, trapped water intensifies the formation of blockages leading to a reduction in relative permeability to gas in the invaded zone (Bahrami et al., 2011; Taylor et al., 2009). Restoring saturation in the invaded zone to its original state will minimize the impact of water blocks and can reverse the reduction in gas relative permeability (Liao and Lee, 1993; Sherman and Holditch, 1991). This statement holds true regardless of the means of reduction in saturation. However, original saturation conditions may not be restored since low permeability formations are often subirreducibly saturated (Taylor et al., 2009).

The aim of this experimental study is to determine how saturation distribution in the neighborhood of the fracture impacts gas flow as a function of leakoff volume and shut-in time. Gas flow hindrance is quantified in terms of regained permeability. This is the ratio of the initial permeability that is regained following a leak off and shut-in period. Regained permeability can be a function of leakoff volume and the length of the shut-in period (Taylor et al., 2009). Greater leak off increases depth of invasion which makes it more challenging to produce back the invading water and results in lower water recovery (Bahrami et al., 2011; Parekh and Sharma, 2004). Fracturing fluid saturation within the vicinity of the fracture is increased and gas peak rates are delayed. On the other hand, longer shut-in times, in a reservoir without fracture face damage, promote spontaneous imbibition of the invading fluid away from the fracture. This generally favors gas production (Sherman and Holditch, 1991).

The time required for the fluids to imbibe far enough away from the fracture is dependent on the permeability of the formation. Lower permeability formations require longer shut-in times for imbibition because fluid mobility is directly proportional to the effective permeability of the formation. In fact, there could be cases of very low water mobility such that imbibition takes a significant amount of time (Sherman and Holditch, 1991). Dutta et al. (in press) found that the low permeability and heterogeneities in tight formations compete with the strong capillary forces. Moreover, Settari et al. (2002) and Cheng (2012) found that very long shut-in times can decrease water production significantly due to imbibition but may have negligible effect on long term production. There is a need to understand the relationship between shut-in period, leak off volume and gas production. These experiments focus on the invasion of fracturing fluid filtrate alone. The evolution of saturation distribution is of interest and is monitored using X-ray CT techniques. X-ray CT imaging is a 'radiological imaging technique that measures density and atomic composition inside opaque objects' (Wellington and Vinegar, 1987). This process is a fast, nondestructive, quantitative way of generating internal 3-D depictions of objects. It has many petrophysical applications including but not limited to 3-D measurement of density and porosity, and rock mechanics studies. Hence, it provides an excellent platform to visualize and quantify the changing distribution of water within a core sample.

2. Materials and methods

2.1. Rock samples

Three experimental samples (A, B & C) were cored from the Mesaverde section, Colorado. These cylindrical samples are 3.81 cm in diameter and 17.78 cm in length, resulting in an aspect ratio that facilitates both X-ray CT scanning and permeability measurements. Although similar, samples A, B and C exhibit different permeabilities. Sample B has the lowest base permeability of 2.07×10^{-15} m^2 (2.1 mD) while samples A and C have base permeabilities of 4.74×10^{-15} m^2 (4.8 mD) and 4.93×10^{-15} m^2 (5 mD) respectively. The average porosity of these samples was estimated by Core Laboratories and an in-house Helium porosimeter PORG-200 to be 19%. Further, Fig. 1 displays the capillary pressure curves associated with these samples as developed using equation 1 of Gdanski et al. (2005).

2.2. Experimental setup

The experiment performed in this investigation was designed to quantify the gas flow hindrance caused by a leak off of water-based fracturing fluid into the adjacent matrix through the fracture face. Fig. 2 is a diagram showing the concept behind this experiment and how the rock samples correspond with the region of interest. The

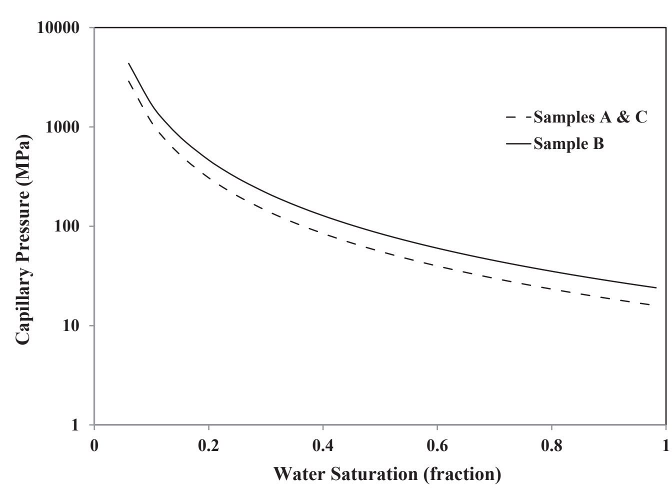

Fig. 1. Capillary pressure curves associated with samples A, B and C.