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Experimental investigation of shale gas production impairment due to fracturing fluid migration during shut-in time

Q. Yan, C. Lemanski, Z.T. Karpyn, L.F. Ayala*

John and Willie Leone Family Department of Energy and Mineral Engineering and EMS Energy Institute, The Pennsylvania State University, University Park, PA, 16802, USA

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A B S T R A C T

Hydraulic fracturing has been applied to exploit hydrocarbon resources for a number of decades. During the fracturing process, large amounts of pressurized fracturing fluid is injected to create and to propagate the fracture. In the exploitation of unconventional reservoirs, fracturing fluid recovery can be very low and even less than 10%. Any unrecovered fracturing fluid can be imbibed into the formation and block the rock pores, thus reducing the effective permeability of gas and causing gas production impairment. This study investigates gas production impairment due to spontaneous migration of fracturing fluid into a shale formation as a function of shut-in time. Core flooding experiments were designed to mimic initial leak-off volume, followed by shut-in time and flow back. Results are presented in terms of regained permeability ratios as a function of shut-in time. Findings from this work indicate that the regained permeability of shale slightly decreases with shut-in time, as the fluid front propagates within the rock. Results are also compared to previous experiments on tight sand cores. From this comparison, it was concluded that lithology also plays a determining factor in the relationship between shut-in time and regained permeability. The level of impairment caused by fracturing fluid migration was found to be significantly higher in shale cores than tight sands, which is attributed to the inherent lower permeability of shale formations.

1. Introduction

Hydraulic fracturing with water-based fracturing agents is the most widely used stimulation technique in shale gas formations (Palisch et al., 2010). Fracturing fluid recovery after flowback has been found to vary widely in formations such a shales (Wang et al., 2012). This loss of fracturing fluid is thought to leak off into the formation, causing water blockage in the vicinity of fractures and thus reducing the effective permeability of gas. Other problems accompanying fracturing fluid leak-off is clay swelling. Clay dispersion can also hinder permeability as a result of fracturing fluid invasion in a clay-rich formation (Bazin et al., 2010). Compared with other permeability damage in fracture-face matrix, fracturing fluid leak-off can cause significant flow impairment. Wang et al. (2012) illustrated, for instance, that the effect of fracturing fluid leak-off can on well productivity impairment can be double that of gel filter cake residue at the fracture face.

Dutta et al. (2014) quantified and compared the extent of capillary migration in low-permeability sands through regained permeability tests. Their study showed that the loss of fracturing fluid to the formation is due to a combination of permeability, capillarity, and heterogeneities present in the formation, subsequently affecting gas production. The analysis provided insights on the effect of the shut-in period of a well on capillary-driven spontaneous migration of fracturing fluids. Sherman and Holditch (1991) and Liao and Lee (1993) argued that restoring saturation in the invaded zone to its original form would lessen the impact of water blocks and reverse the reduction in relative permeability to gas. Gdanski et al. (2005) stated that relative permeability to gas in the nearby region around fractures can be recovered by the fracturing fluid being imbibed deeper into the matrix after fracturing fluid invasion Holditch (1979) used a single-phase, two-dimensional, finite-difference numerical model to investigate the effects of reservoir permeability damage surrounding the fracture. The analysis showed that the cleanup process following a fracture treatment can be directly related to the water mobility in the

* Corresponding author. 103A Hosler Bldg, University Park, PA 16802, USA.
E-mail addresses: qiyanyan12@gmail.com (Q. Yan), lemanski.christina@gmail.com (C. Lemanski), ZKarpyn@psu.edu (Z.T. Karpyn), ayala@psu.edu (L.F. Ayala).

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formation.

The spreading of fracturing fluid in the reservoir rock is controlled by various mechanisms, such as spontaneous imbibition as a result of capillary forces, relative permeability, gravity segregation, and stress-sensitive fracture conductivities (Holditch, 1979; Kamath and Laroche, 2003; Mahadevan et al., 2009; McGowen and Vitthal, 1996). In particular, spontaneous imbibition is considered to be responsible for having a significant impact on the retention of water-based fracturing fluids in the neighborhood of the induced fracture (Dutta et al., 2014). Leak-off volume and shut-in time have been observed to control saturation changes near the fracture, a larger leak-off volume increasing saturation, thus causing a greater hindrance to gas flow. Lee and Karpyn (2010) had also shown that capillary forces can have a significant effect in these processes. Their experiments showed that higher injection flow rates produced higher oil recoveries, sharp imbibing fronts, and saturation gradients. At lower injection rates, smoother saturation gradient resulted.

Shut-in time is considered to be the crucial factor for the regained permeability after leak-off (Taylor et al., 2009). In multi-stage fracturing operations, fractured zones may be shut-in for several days. During these shut-in periods, the invading fluid spreads further into the formation under the effect of capillary pressure. Therefore, restoration of saturation near the fracture can be achieved (Odumabo et al., 2014). However, there remains a lack of understanding regarding the dependencies relating leak-off volume, flow back volume, shut-in time, and gas production, mainly due to the fact that the interaction of these variables differs between formations. Although a number of numerical models, such as the ones stated above, can be built to analyze the fracturing fluid leak-off problems, neither visual nor quantitative evidence of how fracturing fluid migrates in shale rocks has been presented. In this study, a series of core flooding experiments have been conducted in order to quantify gas production impairment due to spontaneous migration of fracturing fluid in shale using shut-in time as the main control parameter. Results of shale are compared against results previously presented by Dutta et al. (2014) and Odumabo et al. (2014) for tight sand systems. In these experiments, the pressure-pulse decay method (Dicker and Smits, 1988) was used for permeability measurements, X-ray computed tomography (CT) generated three-dimensional images of the inner structure of shale cores, and X-ray diffraction (XRD) was also used to examine clay swelling of the tested samples.

2. Materials and experimental method

Fig. 1 shows the conceptualization of the proposed experiments relative to a region of interest at field conditions. The thick, vertical arrows indicate the direction of the invasion and its migration away from the main fractures. One face of the representative sample represents the fracture-matrix face through which the fracturing fluid leaks off, while the other face is the further location in the formation. In the proposed experiments, cored shale samples are exposed to water-based fracturing fluid on one of its sides to trigger and investigate leak-off and migration into the matrix.

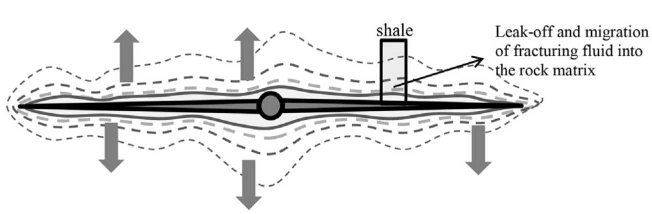

Fig. 1. Conceptualization of field conditions (Dutta et al., 2014).

Three shale samples (Samples A, B, and C) were used for this purpose. Each sample was cored into 0.5 in. in diameter and 2 in. in length for subsequent regained permeability testing In addition to samples A, B, and C, two additional samples (samples D and E) were analyzed by Core Lab Inc. for baseline permeability testing and comparison purposes. The dimensions of the samples can be found in Table 1, and the permeability of the samples can be found in Table 2. Average porosity of the samples was 8.53%. Material composition was also quantified via X-ray diffraction (XRD) for further analysis on clay content and its potential implication on clay swelling during imbibition. XRD patterns were collected on a PANalytical Empyrean diffractometer equipped with a theta/theta goniometer utilizing CuKα X-rays. The interlayer spacing, also known as d-spacing, was calculated using Bragg's law in order to investigate clay swelling. XRD patterns were collected on both the dry sample and on the sample after wetting by fracturing fluid.

A schematic of the experimental procedure is shown in Fig. 2. Each set of experiments begins with a base permeability measurement of the cored shale sample under study, using dry nitrogen and the pressure-pulse decay approach (Step 1). After measuring the base permeability, an initial leak-off volume (0.19 cc of water, approximately 1/3 of a pore volume) is introduced by forced injection of water-based fracturing fluid into only one face (inlet) of the sample (Step 2). During injection, the opposite face (outlet) is kept open to avoid pressure build-up in the sample. Both the inlet and outlet are then closed, and the initial leak-off volume is allowed to propagate by spontaneous imbibition during a predetermined shut-in time. In the final step (Step 3), the new permeability of the sample is determined using the same pressure-pulse decay approach. Instead of dry nitrogen, humidified nitrogen is applied in this step in order to avoid mass transfer between nitrogen and fracturing fluid inside the sample. At regular shut-in time intervals, humidified nitrogen is then flown countercurrently (i.e., towards the inlet face from where the initial leak-off was injected) to replicate the flowback effect and estimate the new effective permeability to gas after leak-off at that time. Results are then quantified in terms of the regained permeability ratio, defined as the ratio of the new (regained after leak-off) permeability to the initial sample permeability measured prior to leak-off. Multiple measurements of regained permeabilities are performed to verify reproducibility and observe its behavior with time. Samples are subjected to a 600 psi confining pressure during all steps.

Five tests with different water saturation and shut-in periods were performed on Sample A. Sample A was the base sample for which multiple shut-in experimental trials were implemented. In total, Sample A was re-used for five regained permeability experiments. After the end of each experiment, the sample was place into a heating oven at 100+ °C for as long as needed until the weight of the sample did not decrease anymore so that water evaporation out of the sample was completed. For the first three trials using Sample A (lasting each up to 72, 360, and 48 h), it was assumed that the sample had regained its original permeability after water evaporation. However, this assumption had to be reformulated when, prior to execution of the fourth test, the base permeability of the dried sample was measured and a significant drop in permeability

Table 1
Shale samples' dimensions.

	Sample	Value	Unit
Diameter	A, B, C, and D, E	0.0127	m
		0.0254	m
Length	A, B, C, D, and E	0.0508	m