Applied Clay Science 161 (2018) 290–300

Contents lists available at ScienceDirect

Applied Clay Science

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

Research paper

Shale softening: Observations, phenomenological behavior, and mechanisms

Jianting Du[a,b], Liming Hu[a,*], Jay N. Meegoda[a,c], Guoping Zhang[d,*]

[a] State Key Laboratory of Hydro-Science and Engineering, Department of Hydraulic Engineering, Tsinghua University, Beijing 100084, China
[b] PowerChina Kunming Engineering Corporation Limited, Kunming 650051, China
[c] Department of Civil and Environmental Engineering, New Jersey Institute of Technology, NJ 07102, USA
[d] Department of Civil and Environmental Engineering, University of Massachusetts Amherst, MA 01003, USA

ARTICLE INFO

Keywords:
Shale softening
Fracture conductivity
Mechanical properties
Clay-fluid interactions
Mineral dissolution

ABSTRACT

Spurred by the advanced technologies, mainly including horizontal drilling and hydraulic fracturing, shale gas exploration has grown significantly over the past few decades. Upon exposure to the aqueous fracturing fluids in the high temperature and high pressure subsurface, the mechanical properties of shales such as elasticity, hardness, and strength usually deteriorate, a phenomenon termed “shale softening”. As a complex, multiphase, and multiscale material, shale is prone to the change in its mechanical properties upon exposure to fracture fluids. It is generally agreed that shale softening has great impact on the design and operation of shale gas exploration and the long-term gas production. This paper provides a critical review of the observed, phenomenological behavior of shale softening, and summarizes the currently recognized potential or hypothesized underlying mechanisms. The former includes: (1) reduction in fracture conductivity and hence the rate of gas production; (2) degradation of mechanical properties and reservoir fracability; (3) creep and long-term damage to the shale formations. The latter consists of clay-fluid interactions, electrical double layer (EDL) repulsion, solid mineral dissolution, short-term unloading, and long-term creep. However, to date, the dominant mechanisms controlling shale softening for a rock with known mineralogical compositions and the chemistry of fracturing fluids still remain unresolved. Our preliminary investigations suggest that the dominant mechanism depend on shale's compositions. Therefore, knowledge of the mineralogy of a shale is proposed as an essential requirement for the development of a framework for probing the mechanisms of shale softening. It is expected that such a newly proposed framework can practically facilitate the design and operation of shale gas exploration and help achieve stable gas production over an extended duration.

1. Introduction

With ever-increasing demand for cleaner energy and the continuously declining production of oil/gas from conventional reservoirs, shale formations as major unconventional energy resources are playing a vital role in meeting the global energy needs of the future. The *Annual Energy Outlook* suggests that the shale gas is the largest contributor to growth of natural gas production, with roughly 50% of the total natural gas production in the United States in 2016, and will account for nearly two-thirds of total U.S. production by 2040 (U.S. Energy Information Administration, 2017). Unlike conventional reservoirs, shale is a kind of ultra-tight rock with relatively low pore connectivity (Hu et al., 2012; Mehmani et al., 2013; Zhang et al., 2015a), and extremely low permeability (Amann-Hildenbrand et al., 2012; Sakhaee-Pour and Bryant, 2012; Zhang et al., 2015b; Zhang et al., 2017). To achieve economical and commercially viable production from shale formations, large-scale drilling and fracturing are necessary to generate complex fracture networks. With the evolution of shale gas exploration since 1981, slick water is now used instead of the cross-linked gel which was used before. When comparing with cross-linked fluids, slick water has several advantages, including less formation damage, lower cost (because the water content can be as high as 99.5%), and a higher possibility of creating complex fracture network (Schein, 2004; Cipolla et al., 2009; Cheng, 2012; Gomaa et al., 2014). The primary composition of slick water is water, and only about 20–40% of fracturing fluid is recovered (Byrnes, 2011; Roychaudhuri et al., 2013). However, shale minerals interact with water-based fracturing liquids, especially when the fractured surfaces of the formation bearing different kinds of compositional minerals are exposed. Such interactions can lead to the softening of shale, which is exhibited by reduced stiffness, hardness, and strength.

In this paper, an overview of recent investigations of observations and phenomenological behavior of shale softening is presented and the mechanisms causing such shale softening are discussed. There are three consequences of shale softening: (1) the softening of formation can

* Corresponding authors.
E-mail addresses: gehu@tsinghua.edu.cn (L. Hu), zhangg@umass.edu (G. Zhang).

https://doi.org/10.1016/j.clay.2018.04.033
Received 24 December 2017; Received in revised form 20 April 2018; Accepted 23 April 2018
0169-1317/ © 2018 Elsevier B.V. All rights reserved.

significantly reduce the effective fracture conductivity leading to decline in gas production; (2) the degradation of shale matrix caused by shale softening decreases the reservoir fracability, especially for re-fracturing and multiple fracturing; and (3) shale softening can increase creep leading to reduced crack openings, reservoir subsidence, wellbore stability, and proppant embedment. Due to the physicochemical interactions of shale minerals with fracturing fluids, clay-fluid interactions, EDL repulsion and minerals dissolution are considered as major mechanisms of shale softening.

2. Decline in shale gas production and reduction in gas conductivity

2.1. Decline in shale gas production

Pope et al. (2009) mentioned that in classic sandstone reservoirs, the initial production (IP) was commonly used as a measure of the performance success of various completion practices. However, with ultra-low permeability of shale, the fracture conductivity between the reservoirs and wellbores is critical. The density and conductivity of fracture network significantly contribute to gas production. For most of shale formations, the gas production should be divided into initial production (IP) and long-term production since they are quite different. The IP mainly relates to lateral length, number of fracturing stages and size of the job (proppant volume) and it tends to reflect how much rock has been exposed by a given completion. Data from Haynesville-Bossier (HB) Shale showed that IP of wells increased with the increasing length of the lateral and total number of stages (with relatively constant proppant volume per stage).

Baihly et al. (2010) summarized the average gas production rate per well for wells that were grouped by their first production date in different shale basins across the US. Gas-production rate declined rapidly within the first few months. Valkó and Lee (2010) compiled monthly production data from selected Barnett shale wells. As shown in Fig. 1, the newer wells have a higher IP, but the production rates declined rapidly. The improvement in technology and field operations generated a denser fracture networks creating larger IP. However, the rapid decline in production rate could be either due to depletion of methane or the decline in fracture conductivity between the reservoirs and wellbores. The fracture conductivity between the reservoirs and wellbores is critical for gas production and the loss of fracture conductivity within a few months seems to be the main reason for the steep decline in gas production and causing significant decrease of the long-term production as re-fracturing is shown to generate similar or higher initial gas production rates.

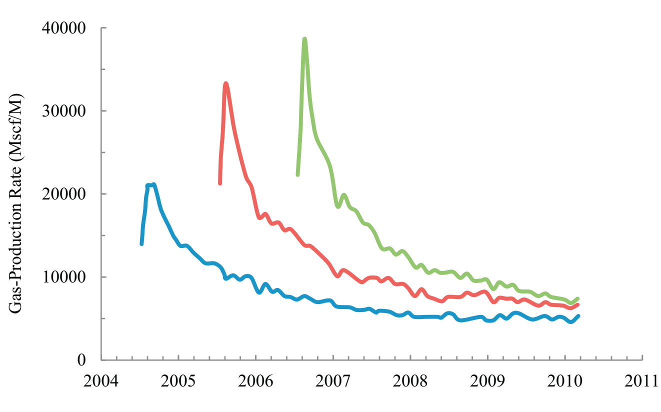

Fig. 1. The variation of average gas-production rate of three selected Barnett shale wells with production time.
Modified from Valkó and Lee (2010).

2.2. Reduction in conductivity

Fracture conductivity (FC) is dependent on the thickness of proppant pack and its permeability (Fig. 2a) (Barree et al., 2003). Different mechanisms can contribute to the impairment of fracture hydraulic conductivity including fines migration (Pope et al., 2009), proppant crushing (Terracina et al., 2010), proppant diagenesis (LaFollette and Carman, 2010), and reduction in fracture aperture due to the embedment of proppants into the surface of the hydraulic fracture (Huitt and McGlothlin Jr, 1958; Terracina et al., 2010). Shale softening will increase proppant embedment and hence reduce the fracture aperture. The reduction in fracture aperture significantly reduces the effective fracture conductivity causing long-term decline in gas production.

2.2.1. Proppant embedment

The softening of shale has the potential to increase proppant embedment into the fracture face, resulting in reduced fracture thickness and conductivity. This reduction in conductivity can, in turn, determine whether the production of reservoir is economically feasible. As shown in Fig. 2b, proppants can embed into the fracture face, especially in soft shale formations. The shale gas flow rate is based on cubic law; hence for example when the fracture is closed by 10%, there is 27% reduction in flow rate. Therefore, a significant reduction in fracture conductivity can occur with the proppant grains embedding into the fracture face. The flow area of the proppant layer decreases sharply with the increase in the embedment depth as highlighted in red in Fig. 2c. Many researchers have studied the proppant embedment and FC reduction. Penny (1987) performed several tests to investigate the effects of environmental conditions and fracturing fluids on the long-term conductivity of proppants. They found that proppant embedment can lead to reduce the fracture width and lower fracture flow capacity. Lacy et al. (1998) concluded that embedment can be significant when the static Young's modulus is less than 13 GPa or when the core hardness value is less than about 20 kg/mm^2, and embedment of 55% and 300% of the proppant diameter with multiple proppant layers were observed for dry and wet core plugs respectively. LaFollette and Carman (2010) found that the softening of Haynesville Shale due to exposure to fracturing fluid increased proppant embedment and significantly decreased proppant pack conductivity. Alramahi and Sundberg (2012) studied effects of proppant embedment on hydraulic fracture conductivity of shale and showed that high proppant embedment was associated with shale samples of high clay contents and/or low static Young's moduli. Corapcioglu et al. (2014) investigated the impact of fracturing fluid on proppant embedment in shale and found that the largest embedment of 31% of its volume after the samples were exposed to a solution of KCl heated to 180 °F for five days. Zhang et al. (2015) concluded that the conductivity loss was due to proppant embedment as the shale fractured surface was softened after its exposure to water. Zhang et al. (2015) also showed that the average embedment depths were approximately 15% and 50% of the median diameter of the proppant in fractures that were exposed to air and water respectively and up to 88% of the undamaged Barnett shale fracture conductivity was lost after water flow under 28 MPa closure stress.

2.2.2. Generation of fines in the formation

An additional issue associated with proppant embedment is the creation of formation fines (spalling) which can migrate and cause additional loss of fracture conductivity. As proppant embeds into the shale fracture face under high overburden stress, formation fines are generated. Proppant fines will reduce pack porosity and permeability, and cause reduction in the conductivity of proppant packs. Coulter and Wells (1972) and Lacy et al. (1997) showed that with just 5% proppant fines, proppant pack conductivity is significantly reduced. Khilar and Fogler (1983) showed that the permeability can be reduced by two orders of magnitude due to fines migration in sandstones. Gidley et al. (1995) showed that increasing the flow rate of hydraulic conductivity

Download English Version:

https://daneshyari.com/en/article/8045810

Download Persian Version:

https://daneshyari.com/article/8045810

Daneshyari.com