Journal of Petroleum Science and Engineering 142 (2016) 119–128

Contents lists available at ScienceDirect

Journal of Petroleum Science and Engineering

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

Dual-permeability microstratigraphy in the Barnett Shale

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ARTICLE INFO

Article history:
Received 17 August 2015
Received in revised form
8 December 2015
Accepted 2 February 2016
Available online 3 February 2016

Keywords:
Mudrocks
Heterogeneity
Core analysis
Dual-permeability

ABSTRACT

We observed multi-scale porosity and permeability at the cm-scale in a Barnett Shale core through a pulse-decay permeability test. The core is composed of alternating layers of silty-claystone and claystone. We interpret the silty-claystone has a permeability of 3.41×10^{-20} m^2 (34.6 nD) and a porosity of 5.6% and that the claystone has a permeability of 1.80×10^{-23} m^2 (0.0182 nD) and a porosity of 4.8%. The horizontal effective permeability is 2.05×10^{-20} m^2 (20.8 nD) and we estimate the vertical effective permeability to be 4.58×10^{-23} m^2 (0.0452 nD). The effective permeability anisotropy ratio is approximately 450. These results suggest that relatively high-permeability carrier beds drain organic rich lower permeability beds. The microstratigraphy of mudstones has a fundamental control on flow, and may provide an explanation for recent studies that have suggested either pervasive natural fracturing or extraordinary levels of induced fracturing are necessary to explain shale production behavior.

1. Introduction

Fine-grained formations contain important hydrocarbon resources worldwide. The broad conceptual view is that the production rates and the cumulative recovery are controlled by the matrix permeability, the distribution of natural fractures, and the spacing between adjacent hydraulic fracture “stages” (Gale et al., 2014; Patzek et al., 2013). Because hydraulic fracture stimulation is a major expense, optimizing shale gas development requires precise knowledge of matrix permeability (Grieser et al., 2008).

Well-test data or production data are commonly used to estimate matrix permeability at the reservoir-scale. However, this approach may require very long timescale production data (Clarkson, 2013; Patzek et al., 2013). Even if such a well test could be made, the fracture spacing must be known in order to interpret the matrix permeability (Patzek et al., 2013; Warren and Root, 1963). Unfortunately, in-situ fracture networks are complex (Gale et al., 2014) and shale matrix is naturally heterogeneous across multiple length scales ($<10^{-4}$–10^{4} m) (Loucks and Ruppel, 2007).

An alternative approach to understanding matrix permeability is to measure permeability at the core-plug-scale. The transient pulse-decay technique (Brace et al., 1968; Dicker and Smits, 1988) is commonly used to measure permeability in shale. Permeability is calculated by measuring the dissipation of a pressure-pulse applied at one end of a core sample. Pulse-decay measurements can also illuminate permeability heterogeneity at the core scale because the pulse-decay behavior of cores with heterogeneous permeability differs in a predictable manner from the response predicted for cores with homogeneous permeability (Kamath et al., 1992). Ning (1992) used pulse-decay testing to illuminate the presence of layer-parallel fractures in core samples and define matrix versus fracture permeability.

We describe a pulse-decay permeability test on a Barnett Shale core sample composed of cm-scale layers of alternating silty-claystone and claystone. Gas first flows rapidly through more permeable layers, and then gas flows slowly into the low permeability layers. We present an analytical dual-permeability model to explain the observed pressure dissipation and characterize permeability in the layers. We interpret that our sample is composed of cm-scale layers of higher permeability silty-claystone ($\sim 3.41 \times 10^{-20}$ m^2, 34.6 nD) interbedded with lower permeability mudstone ($\sim 1.80 \times 10^{-23}$ m^2, 0.0182 nD) and that the resultant effective permeability anisotropy ratio is approximately 450. We propose a conceptual model whereby relatively high-permeability carrier beds act as conduits to drain organic rich lower permeability beds and suggest that this contrasts models (Gale et al., 2014; Patzek et al., 2013) that have proposed meter-scale natural

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http://dx.doi.org/10.1016/j.petrol.2016.02.003
0920-4105/

Nomenclature

Latin

a_E	Dimensionless ratio of high permeability layers pore volume to upstream reservoir volume, V_{p1}/V_u
b_E	Dimensionless ratio of high permeability layers pore volume to downstream reservoir volume, V_{p1}/V_d
C	Compressibility, Pa^{-1}
D	Core diameter, cm
H	Model thickness ($H=\sqrt{\pi/4}D$), cm
H_1	Cumulative high permeability layers thickness, cm
H_2	Cumulative low permeability layers thickness, cm
h_1	Thickness of individual high permeability layer, cm
h_{2eq}	Equivalent thickness of individual low permeability layer, cm
k_H, k_V	Effective horizontal and vertical permeability of homogeneous core, respectively, m^2 or nD
k_1	Isotropic permeability in high permeability layers, m^2 or nD
k_2	Isotropic permeability in low permeability layers, m^2 or nD
L	Core length, cm
L_{eq}	Equivalent core length in late-time model, cm
m_E	Early-time model dimensionless pressure dissipation slope, s^{-1}
m_L	Late-time model dimensionless pressure dissipation slope, s^{-1}
N_1	Number of high permeability layers
N_2	Number of low permeability layers
P_C	Absolute (hydrostatic) confining pressure, Pa
P_{conv}	Early-time reservoir convergence pressure, Pa
P_{eqb}	Late-time final equilibrium pressure, Pa
P_u, P_d	Upstream and downstream reservoir pressure, respectively, Pa
P_{u0}	Initial upstream reservoir pressure after opening main valve, Pa
P_0	Initial pore pressure in sample and downstream reservoir, Pa
P_2	Pore pressure in the low permeability layers, Pa
t	Time, s
t_D	Dimensionless time
V_B	Bulk volume of the core, cm^3
V_{pB}	Total pore volume of core, cm^3
V_{p1}	Total pore volume within all high permeability layers, cm^3
V_{p2}	Total pore volume within all low permeability layers, cm^3
V_u, V_d	Upstream and downstream reservoir volume, respectively, cm^3
W	Model width ($W=\sqrt{\pi/4}D$), cm
Z_{eqb}	Real gas deviation factor at P_{eqb} (dimensionless)
Z_{u0}	Real gas deviation factor at P_{u0} (dimensionless)
Z_0	Real gas deviation factor at P_0 (dimensionless)
x, y, z	Distance coordinates (x=parallel to flow direction, z=normal to layers), *cm*

Greek

γ	Dimensionless layer porosity ratio, ϕ_1/ϕ_2
μ	Dynamic viscosity, Pa*s
τ_{conv}	Characteristic timescale for early-time convergence, s
τ_{eqb}	Characteristic timescale for late-time equilibrium, s
ϕ_B	Bulk porosity of core sample, (fraction)
ϕ_1	Porosity of an individual high permeability layer, (fraction)
ϕ_2	Porosity of an individual low permeability layer, (fraction)
ω	Fraction of total pore volume residing in high perm. layers

Subscripts

E	Early-time system property
L	Late-time system property
1	High permeability material property
2	Low permeability material property

or induced fractures to explain observed production.

2. Sample characterization

The Barnett Shale core we study is oriented parallel to bedding (Sample 6H1) and is from the Mitchell Energy T.P. Sims #2 Well, Fort Worth Basin, Texas, U.S.A (Loucks and Ruppel, 2007). Bhandari et al. (2015) describe multiple experiments on samples in this location. X-ray powder diffraction (XRPD) analysis (Bhandari et al., 2015) indicates that Core 6H1 is dominated by quartz (43.1%), dolomite (22.7%), and illite+illite-smectite (17.1%). It is composed of 25.62% carbonate by weight and its helium porosity (measured for intact plug at ambient stress conditions) is 4.1 ± 1.0% (Bhandari et al., 2015). The bulk TOC value is 3.77 wt% and the vitrinite-reflectance thermal maturity is 1.89% (Bhandari et al., 2015), placing it well within the gas window.

X-ray micro-computed tomography (CT) revealed cm-scale alternating layers of light and dark material; high attenuation (higher density) light layers are approximately (6–12) mm thick and low attenuation (lower density) dark layers are approximately (4–8) mm thick (Fig. 1a). No microfractures are visible in CT images. The high density layers are siliceous silty-claystone (~25–30% silt-sized versus 65–70% sub-silt sized particles) and the low density layers are claystone (~10–15% silt-sized versus 85–90% sub-silt sized particles) (Fig. 1a, c, and d).

The high-resolution SEM images confirm that organic matter is present in both the silty-claystone and claystone (Fig. 1e and f). We estimate the concentration of organic material (solids plus porosity) in the claystone is 16 ± 4 vol%, approximately twice that within the silty-claystone 7 ± 4 vol%. Claystone layers comprise 40 vol% of the core bulk volume (Fig. 1a); thus we interpret that ~50–60% of the total organic material resides in claystone. We interpret the origin of the organic matter in these two layers are different. The organic matter within the claystone (Fig. 1f) is largely detrital kerogen whereas the organic matter within the silty-claystone (Fig. 1e) is largely bitumen that has migrated into the larger pores within the silty-claystone (e.g., Loucks and Reed, 2014).

3. Pulse-decay experimental results

We performed pulse-decay permeability measurements (Brace et al., 1968; Hsieh et al., 1981) as reported in Bhandari et al. (2015) (Fig. 2a). The confining pressure was 41.36 ± 0.03 MPa which corresponds to the insitu stress condition. The upstream pressure was 7.433 ± 0.016 MPa (1078 psi), the sample and downstream