Journal of Unconventional Oil and Gas Resources 10 (2015) 1–10

Contents lists available at ScienceDirect

Journal of Unconventional Oil and Gas Resources

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

Fracture permeability and relative permeability of coal and their dependence on stress conditions

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ARTICLE INFO

Article history:
Received 28 September 2013
Revised 17 August 2014
Accepted 8 February 2015
Available online 21 February 2015

Keywords:
Coal bed methane
Relative permeability
Fracture
Stress

ABSTRACT

Determination of petro-physical properties of coal bed methane (CBM) reservoirs is essential in evaluating a potential prospect for commercial exploitation. In particular, permeability of coal and relative permeability of coal to gas and water directly impact the amount of hydrocarbons that can be ultimately recovered. Due to the complex and heterogeneous nature of coal seams, proper relative permeability relationships are needed to accurately describe the transport characteristics of coal for reservoir modeling and production forecasting. In this work, absolute and relative permeability of different coal samples were determined experimentally under steady-state flowing conditions. Multiphase flow tests were conducted using brine, helium and carbon dioxide as the flowing phases under different magnitudes of confining and pore pressures. Results indicate that effective stress (confining pressure – average pore pressure) has a significant effect on both absolute and relative permeability of coal. With increases in effective stresses, the absolute permeability decreases. Effective permeability and relative permeability, as well as the cross over point and the width of the mobile two-phase region decrease as the effective stress increases. In addition, the mobile range of gas and water in the coal samples investigated corresponds with water saturations above 50%, irrespective of the base absolute permeability of the sample. In brine–carbon dioxide two-phase flow experiments, the effect of carbon dioxide adsorption was observed as effective permeabilities decreased in comparison to the helium–brine permeabilities at the same flowing ratios. As a result, relative permeability characteristics of CBM systems were found to be insufficiently represented as sole functions of fluid saturation. Field scale simulations of primary recovery from CBM systems using variable, stress-dependent relative permeabilities, showed a significant decrease in cumulative gas recovered. A multi-dimensional correlation between relative permeability, fluid saturation and specific surface area of the cleat network is proposed as a continuation from this work in order to account for stress-related changes in cleat network connectivity.

Introduction

Methane production from coal seams has been practiced for more than half a century and successful commercial exploitation of coal bed methane systems has been witnessed on a global scale, especially in the United States. It is estimated that the global methane reserves from coal seams can be up to 9500 Tcf and in the US up to 3000 Tcf (Olsen et al., 2003). For reservoir engineering applications coal seams are treated to be dual porosity in nature having a tight matrix and a well defined natural fracture or the cleat system. Coal seams undergo a multi-mechanistic depletion process (Ertekin et al., 1988) where gas desorbs and diffuses from the matrix into the natural fractures and from the natural fractures it flows to the wellbore. Generally when gas desorbs from the micropores, the matrix shrinks which leads to an increase in permeability (Harpalani and Shraufnagel, 1990) and when gas adsorbs, the permeability decreases due to matrix swelling. Hence the interaction of gases with the observed changes in coal permeability accompanied by shrinkage/swelling characteristic of coal is a complex phenomenon. Hence research interest has increased in the recent past to study and understand the behavior of different types of coals for long term reservoir monitoring and management. Among these, research investigations aimed at

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http://dx.doi.org/10.1016/j.juogr.2015.02.001
2213-3976/

understanding the relative permeability characteristics of coal seams which primarily describes the flow of water and gas in the cleat or the fracture network has been very minimal (Dabbous et al., 1973; Reznik et al., 1974; Puri et al., 1991; Gash et al., 1992; Paterson et al., 1992; Hyman et al., 1992; Ham and Kantzas, 2011; Shen et al., 2011).

The major uncertainties with respect to relative permeability measurements were attributed to sample size, low absolute permeabilities, measurement methods, presence of minerals, experimental conditions and hysteresis effects. Even among samples from the same basins, there were significant differences in measured relative permeability values underlining the complex nature of coal. Since fractures in coal serve as the primary channels through which gas and water flow, changes in fracture apertures due to changing stress conditions could be significant to affect gas and water flow in fractures. Some of the variations in the observed relative permeabilities in these studies could be due to not accounting for the effects of effective stress on two-phase flow in the fracture network. Coal being a naturally fractured formation exhibits strong dependence of permeability on stress conditions (Palmer and Mansoori, 1996; Pan et al., 2010). Effective stress, which is the difference between the overburden stress and the pore pressure, is the one that actually controls the permeability and coal's permeability is strongly affected by effective stress (Connell et al., 2010). Although coal's absolute permeability variation with effective stress/sorption phenomena has been well studied and understood (Harpalani and Chen, 1995; Seidle and Huitt, 1995; Palmer and Mansoori, 1996; Levine, 1996; Shi and Durucan, 2005; Robertson and Christiansen, 2007) the relative permeability behavior of coal in response to changes in effective stress/sorption phenomena is difficult to predict. Detailed description of multiphase flow in fractures and the effect of net overburden stress on two phase flow have not been addressed before. Furthermore, relative permeability relationships are hysteretic in nature and non-unique as they are affected by saturation history (drainage and imbibition cycles). Traditional representation of fracture relative permeabilities as functions of fluid saturations as inputs to CBM simulators can be insufficient to capture the dynamic variations of gas and water flow happening in the fracture network due to varying stress conditions. Current CBM models (dual porosity models) use relative permeability relationships that span the entire window of saturation or straight line relative permeability relationships for describing the flow of gas and water in the fractures. Assuming a straight line relative permeability description as inputs in dual porosity reservoir simulators for describing the multiphase flow in fractures can lead to an oversimplification. Therefore more experimental investigation is needed that explicitly determines the effect of effective stress on the transport of water and gas in the coal fractures. The primary objectives of this work are threefold. Firstly, to determine the effect of effective or net stress on the flow of gas and water in coal fractures, Secondly to identify any observable trend on the relative permeability behavior due to changing stress conditions and thirdly to conduct simulation studies based on the experimental results.

Experimental set-up and procedure

The samples used in the present study are coal cores predominantly obtained from bituminous coal seams in Marshall County, West Virginia. Samples 1, 2 and 3 were cored from wells at depths of 600–700 ft. Sample 4 was prepared from a coal block originally obtained from a coal processing facility in Clearfield County, Pennsylvania. Sample 1, 2 and 3 were subjected to petrographic and proximate analysis. Table 1a gives the dimensions of the samples. Tables 1b and 1c summarize the results of petrographic and proximate analysis. The mean maximum vitrinite reflectance (R_{max}) of these samples is 0.75% and based on the ASTM coal rank classification scheme they can be classified as high volatile A bituminous coal. All the samples had to be artificially fractured to get absolute permeabilities greater than 1 mD so that they are suitable for single phase and multiphase flow studies. X-ray computed tomography was primarily used for in situ fluid saturation distribution determination. The X-ray scanner used in this work is a 'Universal HD-350E' medical CT scanner, which has a series of detectors arranged on a circumference with the X-ray source rotating around the object positioned in the center. The resolution used here is 0.195 mm × 0.195 mm, with a slice thickness of 1 mm and a detection frame of 512 × 512 voxels. Fig. 1 shows the experimental set up for conducting flow experiments. Gas and brine are taken into the 'pre-saturation unit' which is a pressure vessel capable of being operated up to a maximum pressure and temperature of 3000 psi (21 MPa) and 150 C respectively. Temperature during the experiments was 20 ± 2 C. In this pressure

Table 1a
Dimensions of coal samples used in the study.

Sample #	Sample dimensions	
	Diameter(inch)	Length(inch)
1	2	3.25
2	2	5
3	2	4
4	2	4

Table 1b
Petrographic analysis of the samples – summary. Bold numbers indicate total values.

Maceral	Sample #1		Sample #2		Sample #3	
	%, mmf	%, mmc	%, mmf	%, mmc	%, mmf	%, mmc
Vitrinite, V-types						
6	1	1	12.1	11.4	13.1	12.1
7	81.3	78.6	71.7	67.4	67.9	63
8	13.4	12.9	9.3	8.7	6.1	5.6
Total Vitrinite	**95.7**	**92.5**	**93.1**	**87.5**	**87.1**	**80.7**
Liptinite						
Sporinite	0.4	0.4	0.8	0.8	2.6	2.4
Resinite	0.2	0.2	0.1	0.1	0.1	0.1
Cutinite	1.2	1.2	1	0.9	1	0.9
Liptodetrinite	0.4	0.4	0.2	0.2	0.6	0.6
Total Liptinite	**2.2**	**2.2**	**2.1**	**2**	**4.3**	**4**
Inertinite						
Fusinite	0.5	0.5	0.8	0.8	2.4	2.2
Semifusinite	0.5	0.5	1.9	1.8	3.9	3.6
Macrinite	0.2	0.2	0.1	0.1	0.4	0.4
Micrinite	0.6	0.6	1	0.9	0.6	0.6
Inertodetrinite	0.3	0.3	1	0.9	1.3	1.2
Funginite						
Mineral Matter	–	3.2	–	6	–	7.3
Total Inertinite	**2.1**	**5.3**	**4.8**	**10.5**	**8.6**	**15.3**
R_{max}, StD n = 100	0.77%, 0.03		0.74%, 0.04		0.75%, 0.04	

Table 1c
Proximate analysis of samples – summary.

	Sample #1		Sample #2		Sample #3	
	Dry	daf	Dry	daf	Dry	daf
%Volatile matter	41.17	44.26	39.61	45.47	36.56	44.9
% Fixed Carbon	51.85	55.74	47.51	54.53	44.86	55.1
% Ash	6.98		12.88		18.58	
%Total Sulfur	2.53		4.48		2.2	