A novel technology for enhanced coal seam gas recovery by graded proppant injection

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DEDICATION

This thesis is deeply dedicated to:

My parents for all they have done in my life.

My wife for her love, understanding, support, encouragement, sacrifices and prayers offered to me throughout my study.

Contents

Abstract

Coal bed methane (CBM) is one of the world's fastest growing unconventional gas resources and offers the potential for much cleaner power than from traditional coal. However, low productivity index in coal bed methane reservoirs places them on the margin of economic efficiency. One of the key technological hurdles affecting the productivity index in CBM reservoirs is the extremely low permeability of coal's natural cleat and fracture system. Thus, development of new techniques for enhancing coal cleat permeability is essential for cost-effective gas production from CBM reservoirs.

The hydraulic fracturing is the most widely used CBM well stimulation method; however, the hydraulic fracturing is often restricted by the environmental regulations. Besides, the available injection power may not be sufficient to fracture the well. The way around this problem is stimulation of a natural cleat system keeping the reservoir pressure below the fracturing pressure.

The main objective of this study is to develop a new well stimulation technology utilizing graded proppant injection to allow sequential filling of both distant and near-well fractures. This mechanism leads to a significant enhancement of permeability and, therefore, improved well productivity. Mathematical modelling and experimental studies are conducted for stimulation of natural cleat system in coal bed methane reservoirs. The aim of this work is to determine an optimum injection schedule, i.e. the timely dependencies of the injected proppant size and concentration that avoids fracture closure during production stage and provides minimum hydraulic resistance in the system of fractures plugged by proppant particles.

The laboratory tests on one dimensional injection of different size particles into coal cores have been conducted under different effective stress conditions. Calculations of electrostatic interactions result in determining the physico-chemical conditions, favourable for particle-particle and particle-coal repulsion. The repulsion prevents: particle attachment to the coal surface, particle agglomeration and consequent formation damage due to external and internal cake formation. Particle placement with low-salinity water, which promotes the repulsion, improves the coal permeability.

A laboratory-based mathematical model is developed to describe the proppant-free water injection stage; capture kinetics of proppant particles in the natural fractures and calculation of an optimal injection schedule. The analytical model is derived for exponential stress-permeability relationship and accounting for permeability variation outside the stimulated zone. Field case studies show that the productivity index can be significantly increased by applying the stimulation technology developed in this thesis. The sensitivity analysis of well index shows that the most influential parameters are the stimulated zone size, injection pressure and the cleat system compressibility.

The above laboratory study, mathematical modelling and the field-scale predictions allow recommending the developed technology of graded proppant injection for improving gas recovery from Coal bed methane reservoirs.

Declaration

I certify that this work contains no material which has been accepted for the award of any other degree or diploma in my name, in any university or other tertiary institution and, to the best of my knowledge and belief, contains no material previously published or written by another person, except where due reference has been made in the text. In addition, I certify that no part of this work will, in the future, be used in a submission in my name, for any other degree or diploma in any university or other tertiary institution without the prior approval of the University of Adelaide and where applicable, any partner institution responsible for the joint-award of this degree.

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Publications

Peer reviewed journal publications

1. **Keshavarz, A.,** Yang, Y., Badalyan, A., Johnson, R., Bedrikovetsky, P., 2014. Laboratory-based mathematical modelling of graded proppant injection in CBM reservoirs. *International Journal of Coal geology* 136, 1–16.
2. **Keshavarz, A.,** Badalyan, A., Carageorgos, T., Bedrikovetsky, P., Johnson, R., 2014. Stimulation of coal seam permeability by micro-sized graded proppant placement using selective fluid properties. *Fuel* 144, 228–236.
3. **Keshavarz, A.,** Badalyan, A., Carageorgos, T., Bedrikovetsky, P., Johnson, R., 2014. Enhancement of CBM well fracturing through stimulation of cleat permeability by ultra-fine particle injection. *Australian Petroleum Production and Exploration Association (APPEA) Journal* 54, 155-166.
4. **Keshavarz, A.,** Mobbs, K., Khanna, A., Bedrikovetsky, P., 2013. Stress-based mathematical model for graded proppant injection in coal bed methane reservoirs. *Australian Petroleum Production and Exploration Association (APPEA) Journal* 53, 337-346.
5. Khanna, A., **Keshavarz, A.,** Mobbs, K., Davis, M., Bedrikovetsky, P., 2013. Stimulation of the natural fracture system by graded proppant injection. *Journal of Petroleum Science and Engineering* 111, 71-77.
6. **Keshavarz, A.,** Badalyan, A., Bedrikovetsky, P., Johnson, R., Improving efficiency of hydraulic fracturing treatment in CBM reservoirs by stimulating the surrounding natural fracture system. *Australian Petroleum Production and Exploration Association (APPEA) Journal* (Accepted)

International conference papers and poster presentations

7. **Keshavarz, A.,** Khanna, A., Hughes, T., Boniciolli, M., Cooper, A., Bedrikovetsky, P. 2014. Mathematical model for stimulation of CBM reservoirs during graded proppant injection, presented at *SPE/EAGE Unconventional conference & Exhibition*, Vienna, Austria, 25-27 Feb, SPE 167758-MS.

8. **Keshavarz, A.,** Badalyan, A., Carageorgos, T., Bedrikovetsky, P., Johnson, R., 2014. Stimulation of unconventional naturally fractured reservoirs during graded proppant injection: experimental study and mathematical model, presented at *SPE/EAGE Unconventional conference & Exhibition*, Vienna, Austria, 25-27 Feb, SPE 167757-MS.
9. **Keshavarz, A.,** Badalyan, A., Carageorgos, T., Bedrikovetsky, P., Johnson, R., 2014. Enhancement of CBM well fracturing through stimulation of cleat permeability by ultra-fine particle injection, presented at *Australian Petroleum Production and Exploration Association (APPEA) Conference and Exhibition*, Perth, Australia, 6-9 April.
10. **Keshavarz, A.,** Mobbs, K., Khanna, A., Bedrikovetsky, P., 2013. Stress-based mathematical model for graded proppant injection in CBM reservoirs, presented at *Australian Petroleum Production and Exploration Association (APPEA) Conference and Exhibition*, Brisbane, Australia, 26-29 May.
11. Bedrikovetsky, P., **Keshavarz, A.,** Khanna, A., Mckenzie, M. M., Kotousov, A., 2012. Stimulation of Natural Cleats for Gas Production from Coal Beds by Graded Proppant Injection, presented at *SPE Asia Pacific Oil & Gas conference and exhibition*, Perth, Australia 22-24 Oct. SPE 158761-MS.
12. **Keshavarz, A.,** Badalyan, A., Bedrikovetsky, P., Johnson, R., 2015. Improving efficiency of hydraulic fracturing treatment in CBM reservoirs by stimulating the surrounding natural fracture system, accepted for presentation at *Australian Petroleum Production and Exploration Association (APPEA) Conference and Exhibition*, Melbourne, Australia, 17-20 May.
13. **Keshavarz, A.,** Badalyan, A., Bedrikovetsky, P., Johnson, R., 2015. Graded Proppant Injection into Coal Seam Gas and Shale Gas Reservoirs for Well Stimulation, accepted for presentation at *SPE European Formation Damage Conference & Exhibition*, Budapest, Hungary, 3-5 June, SPE-174200-MS.
14. **Keshavarz, A.,** Badalyan, A., Bedrikovetsky, P., Johnson, R., 2015. A new technique for enhancing hydraulic fracturing treatment in unconventional reservoirs: experimental study and mathematical modelling, accepted for presentation *at SPE EUROPEC Conference & Exhibition*, Madrid, Spain, 1-4 June, SPE-174354-MS.

Chapter 1

Introduction

1. 1 Background

Demand for energy is growing up significantly while energy supply from conventional oil and gas reservoirs is declining. To fill this gap between energy demand and energy supply, developing unconventional gas reservoirs i.e. shale gas, tight gas, coal bed methane (CBM) etc. is a must. These type of reservoirs usually need different techniques for completion, production and stimulation if compared with conventional ones.

Coal bed methane reservoir is one of the fast growing unconventional gas resources. The largest proven recoverable CBM reserves are in the USA (26.6%), followed by Russia (17.6%), China (12.8%), Australia (8.6%) and India (6.8%) (BP, 2014). In recent years, the number of CBM development projects has rapidly increased. For example, Australia had no CBM production in 1995, but in 2008, four billion cubic meters of natural gas were extracted from Australian CBM reserves (Al-Jubori et al., 2009). However, their low productivity is a commonplace for CBM reservoirs which places CBM production on the margin of economic efficiency (Clarkson, 2013). The main reasons for low CBM well productivity are low aperture and density of the natural fractures and cleats. Well productivity increase is the main challenge for cost effective CBM production. To achieve economical production rates, most CBM wells require some form of stimulation. Thus development of new techniques for enhancing coal cleat permeability is essential for cost-effective CBM production (Palmer, 2010).

The main well stimulation technique in CBM wells is the hydraulic fracturing, including the combined with horizontal wells (Economides and Martin, 2007; Ghalambor et al., 2009; Guo and Ghalambor, 2014; Johnson Jr et al., 2002). However, conventional hydraulic fracturing technique has some limitations in stimulation of natural fracture rocks such as CBM reservoirs. When a hydraulically induced fracture intersects natural fractures, injecting fluid may divert into natural fractures producing short and non-continuous cracks instead of a single massive fracture. It may accelerate fluid leak-off, induce extremely complex fracture geometry and cause inefficient proppant transport (Rahman et al., 2002; Warpinski and Teufel, 1987). Hossain et al. (2000) (Hossain et al., 2002) found that existence of natural fractures in the non-preferred direction of fracture propagation creates fracture tortuosity and consequently needs higher treatment pressure which may lead to treatment failure. In addition to that, sometimes environmental and reservoir sealing restrictions as well as the lack of injectivity power prevent from well stimulation by hydraulic fracturing in unconventional reservoirs (Holahan and Arnold, 2013). The way around this problem is stimulation of a natural cleat system keeping the reservoir pressure below the fracturing pressure (Rahman et al., 2002).

In the current thesis, a new stimulation technique, called graded proppant injection, has been introduced in order to improve permeability of natural fracture systems. The purpose of the proppant injection into a natural cleat is keeping it open during gas production, where pore pressure declines with time. Pressure decreases along each tortuous flow path from well inside the reservoir. So, the fracture aperture also decreases with radius. Therefore, firstly, small particles are injected in order to be strained in remote areas and to plug thin cleats, thus keeping them open during the production. Then, the intermediate sized proppant particles are injected in order to fill in cleats in the bulk of the drainage area. Finally, larger proppant particles are injected to strain cleats near to the well (papers 1, 2, 5).

The efficiency of the graded particle injection depends on whether the rock conductivity is provided by the fractures or pores. In clastic reservoirs with a pore-dominated hydraulic conductivity, the graded particle injection causes pore plugging by the particle straining with the consequent permeability reduction; therefore, the final permeability is lower than the initial permeability. On the contrary, proppant placement can result in permeability increase in rocks with fracture-dominated transport mechanism (e.g., coals, shales, carbonates), where the residual fracture opening after particle placement prevents fracture closure after the effective stress increase (papers 3, 4, 5). In the case of coals, the meso- and micro-porosity are low and discontinuous with initial production dominated by natural fractures and cleats (Clarkson and Bustin, 1999). Permeability of coal beds is dominated by cleat conductivity and is strongly effective stress-dependent (Jasinge et al., 2011; Li et al., 2013; Wang et al., 2010). Therefore, coal bed reservoirs are prospective candidates for stimulation by the graded proppant injection.

Apart from the "fracture-pore" domination criterion, some other parameters may affect the efficiency of the graded proppant injection method. Inadequately defined particle sizes and concentrations may yield conductive fractures blockage without achieving the desired invasion depth (Bedrikovetsky, 2008). The particle-coal attraction, determined by ionic strength and pH of a carrier fluid may form an external filter cake on the injection face (Kalantariasl and Bedrikovetsky, 2013). The effects of the proppant size, proppant concentration and the carrier fluid chemistry on the return permeability of the stimulated natural coal cleat and fracture systems are investigated in papers 3, 4, 5.

Coupling hydraulic fracturing treatment with graded proppant injection technique can improve conductivity of micro-fractures and cleats around the hydraulically induced fractures in CBM reservoirs. In graded proppant injection technique, placing ultra-fine proppant particles in natural fractures and cleats around hydraulically induced fractures at leak-off conditions keeps the coal cleats open during water-gas production. This increases the efficiency of hydraulic fracturing treatment. Improving the efficiency of hydraulic fracturing stimulation using graded proppant injection technique is studied in paper 6.

1.2 Thesis structure:

This is a PhD thesis by publications. Six papers are included in this thesis, of which five papers have been published in peer-reviewed journals and one paper has been accepted to be published in an academic journal.

The main aim of the thesis is proposing a new technology called graded proppant injection for stimulation of cleat system in CBM reservoirs and, consequently, improving gas productivity index. Mathematical models and experimental studies are conducted for developing this technology. The proposed method has been applied on real case studies to predict the productivity enhancement using graded proppant injection.

The thesis body is formed by six chapters. The *first chapter* contains the general aims and introduction of the importance of the work in oil and gas industry. The *second chapter* presents the literature review on CBM reservoirs and stimulation techniques.

Chapters 3, 4 and 5 are novel original chapters of the thesis. The *third chapter* presents mathematical modelling development for graded proppant injection in natural fractured rocks. *Chapter four* focuses on experimental study on different size proppant placement in real coal samples. The *fifth Chapter* develops laboratory-based mathematical modelling study for graded proppant injection in coal bed methane reservoirs. The main statements of scientific novelty presented in *Chapter six* conclude the thesis.

Paper	Chapter	Paper title	Status
1	3	Stimulation of the natural fracture system by graded proppant injection	Published
2	3	Stress-based mathematical model for graded proppant injection in coal bed methane reservoirs	Published
3	4	Enhancement of CBM well fracturing through stimulation of cleat permeability by ultra-fine particle injection	Published
4	4	Stimulation of coal seam permeability by micro-sized graded proppant placement using selective fluid properties	Published
5	5	Laboratory-based mathematical modelling of graded proppant injection in CBM reservoirs	Published
6	5	Improving efficiency of hydraulic fracturing treatment in CBM reservoirs by stimulating the surrounding natural fracture system	Accepted

Chapter one contains a brief summary of shortages in the energy supply in the world, limitations in the existing stimulation techniques and needs for new stimulation methods to improve the gas recovery factor in coal bed methane reservoirs. It allows formulating the aims of the thesis, i.e. developing a new technology for stimulation of natural fracture system in coal bed methane reservoirs using graded proppant injection. The main contextual statement in chapter one is to describe the goal of the PhD study.

Chapter two presents the detailed literature review on gas movement mechanisms, cleat permeability description and recovery limitations in CBM reservoirs. Well stimulation techniques for improving gas recovery from CBM reservoirs, including hydraulic fracturing and natural fracture stimulation, are presented in this chapter. Experimental and theoretical works on optimal proppant placement are reviewed and the gaps in the current literature in proppant particle placement in natural fracture systems are highlighted. The effect of chemistry of carrier fluid, such as pH and salinity of suspension on successful proppant particle injection in fracture system is studied according to Derjaguin-Landau-Verwey-Overbeek (DLVO) theory.

The third chapter contains the description of the proposed graded proppant injection technique, i.e. the injection of particles of increasing size and decreasing concentration, for stimulation of natural fracture rocks. Basic equations for suspension flow in natural fracture rocks are derived. Stress dependent permeability models are used to predict well productivity enhancement due to this stimulation technique. Mathematical models for graded proppant injection are developed which describe the injection stage and capture kinetics of proppant particles in natural fracture systems. Real field data is used for sensitivity analyses and parameter studies.

In chapter four, the technique for graded particle injection below the fracturing pressure has been experimentally evaluated by injection of micro-sized particles into coal cores. A custom made core-flooding system has been developed for performing the experiments. The laboratory tests on one dimensional injection of different sized particles into coal cores have been conducted under different effective stress conditions. Electrostatic interaction studies have been done to determine the physico-chemical conditions, favourable for particle-particle and particle-coal repulsion. The repulsion prevents particle attachment to the coal surface, particle agglomeration and consequent formation damage due to external and internal cake formation.

A laboratory-based mathematical model for graded proppant placement has been developed using experimental data in chapter five. Collecting and measuring proppant particles in effluent has led to successful matching the developed model by experimental data. The steady state flow of suspended particles in fractured system of coal cleats is discussed. Derivations of the model include exponential form of the pressure–permeability dependence and accounts for permeability variation in the non-treated zone. The explicit formulae are derived for the injection schedule and the implicit formula for pressure distribution and well productivity index are developed in this chapter. Tuning the mathematical model from the coreflood data allows for reliable experiment-based behaviour prediction for wells submitted to graded proppant particle injection.

1.3 Relation between publications and this thesis

The paper "Stimulation of the natural fracture system by graded proppant injection" derives a mathematical model for stimulation of natural fracture system by placing different sized proppant particles. The aim of this paper is to determine an optimum injection schedule, i.e. the timely dependencies of the injected proppant size and concentration that avoids fracture closure during production stage and provides minimum hydraulic resistance in the system of fractures plugged by proppant particles. The mathematical model describes the proppant-free water injection stage; capture kinetics of proppant particles in the natural fractures and calculation of an optimal injection schedule. The developed model is used to predict the normalized well productivity index for different injection rates during stimulation and different size of stimulated zone. A case study is conducted to estimate the change in well productivity index due to application of the graded particle injection method.

The mathematical model developed in the paper one is improved in the second paper: "Stress-based mathematical model for graded proppant injection in coal bed methane reservoirs". In this paper, an analytical, stress-based mathematical model describing fluid flow and rock deformation has been developed for graded proppant injection using a coupled fluid flow and geomechanical model. The model is based on an analytical solution of the quasi 1D problem of coupled axisymmetric fluid flow and geomechanics. Explicit analytical equations are derived for stress, pressure and permeability distributions, as well as for the well index during injection and production. It is shown in this paper that there is an optimal stimulation radius in which the maximum productivity index is achieved by applying the graded proppant injection technology.

In the paper "Enhancement of CBM well fracturing through stimulation of cleat permeability by ultra-fine particle injection", experimental procedure, laboratory set-up and injection sequence are described. The DLVO theory is used to study the effects of salinity and pH of a suspension on particle-particle and particle-rock electrostatic interactions. It is found out that the particle injection with high salinity water does not yield the permeability increase due to particle-rock attraction and particle agglomeration, causing the build-up of external and internal cakes near to core inlet preventing the particle deep bed penetration. On the contrary, using low-salinity water with the particle-coal and particle-particle repulsions yields particle penetration into fractured rock with the consequent return permeability increase.

In more details, the experimental procedures are described in the paper "Stimulation of coal seam permeability by micro-sized graded proppant placement using selective fluid properties". Effects of the proppant size, proppant concentration and the carrier fluid chemistry on the return permeability of the stimulated natural coal cleat and fracture systems are investigated in this paper. Using experimental data, an empirical parameter called "permeability shape factor" is introduced. Implementation of the empirical permeability shape factor allows matching the laboratory data by the mathematical model developed in paper 1. The laboratory tuned mathematical modelling as performed for the field conditions shows that the proposed method yields a significant increase in productivity index.

A more complicated mathematical model is developed in the paper "Laboratory-based mathematical modelling of graded proppant injection in CBM reservoirs". The analytical model for axisymmetric flow has been derived for exponential stress-permeability relationship and accounting for permeability variation outside the stimulated zone. Laboratory proppant injections into coal cores have been performed for different proppant sizes and water salinities. Similarly to paper 4, it is shown also that the proppant suspension based on low salinity water prevents the particle–particle and particle–coal attraction with the consequent core inlet plugging and external cake formation. However, low salinity of the injected water may cause mobilisation, migration and straining of the natural reservoir fines resulting in significant formation damage. In this work, experimental studies are conducted to observe the effect of salinity change on fines migration in coal to find an interval where salinity is low enough for the rock inlet not to be plugged by the injected proppant, and is high enough for significant formation damage due to fine migration not to occur. Matching the mathematical model with the experimental data allows for reliable experiment-based behaviour prediction for the wells submitted to graded proppant particle injection.

The main goal of the paper "Improving efficiency of hydraulic fracturing treatment in CBM reservoirs by stimulating the surrounding natural fracture system" is to couple the stimulation technique which has been proposed in the paper 5 with hydraulic fracturing treatment. It stimulates natural cleat network and micro fractures around hydraulically induced fractures, allowing the graded proppants to enter cleats under leak-off conditions and consequently increase the efficiency of hydraulic fracturing in CBM reservoirs. In this work, Experimental and mathematical studies for stimulation of natural cleat system around the main hydraulic fracture are conducted. An experimental coefficient is found for optimum proppant placement in which the maximum permeability is achieved after proppant placement. A laboratory based mathematical model for graded peroppant placement in naturally fractured rocks around a hydraulically induced fracture is proposed. The model presents linear flow from fracture network towards the main fracture in stress sensitive rocks before and after proppant placement. Alternated pressure and permeability distributions after proppant placement are presented by including the experimental coefficient into the model. Field case studies are done to evaluate the enhancement of productivity index by coupling the graded proppant injection technique with hydraulic fracturing treatment.

Finally, the above mentioned 6 journal papers present a new technology, called graded proppant injection, for stimulation of cleat system in coal bed methane reservoirs. Laboratory based mathematical models are developed to predict the recovery enhancement due to applying this technology.

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Chapter 2

Literature review

2.1 Introduction

Coal bed methane is one of the world's fastest growing unconventional gas resources and offers the potential for much cleaner energy than from traditional coal. However, low productivity is a commonplace for coal bed methane reservoirs which places the CBM production on the margin of economic efficiency (Clarkson, 2013). One of the key technological hurdles affecting the commercial viability of CBM operations is the extremely low permeability of coal's natural cleat and fracture system. A unique characteristic of naturally fractured rocks (including coal seams) is that their permeability is sensitive to pressure and stress (Reiss, 1980; Seidle, 2011; van Golf-Racht, 1982). Pressure decline during production, which results in the deformation of the matrix and fractures, therefore, leads to a significant reduction in coal permeability (Palmer, 2009). To achieve economical production rates, most CBM wells require some form of stimulation. Thus, the development of new techniques for enhancing coal cleat permeability is essential for a cost-effective CBM production (Palmer, 2010).

2.2 Coal bed methane reservoir

Coal bed methane reservoir is a kind of naturally fractured reservoirs which consists of two types of cleats: face cleats and butt cleats. Face cleats are long and continuous fractures throughout the coal seam. Face cleat orientations are usually parallel to the direction of the maximum compressive stress. Butt cleats are short and discontinuous fractures perpendicular to the face cleats which usually terminate at intersection with them (Fig. 1) (Harpalani, 1999; Seidle, 2011).

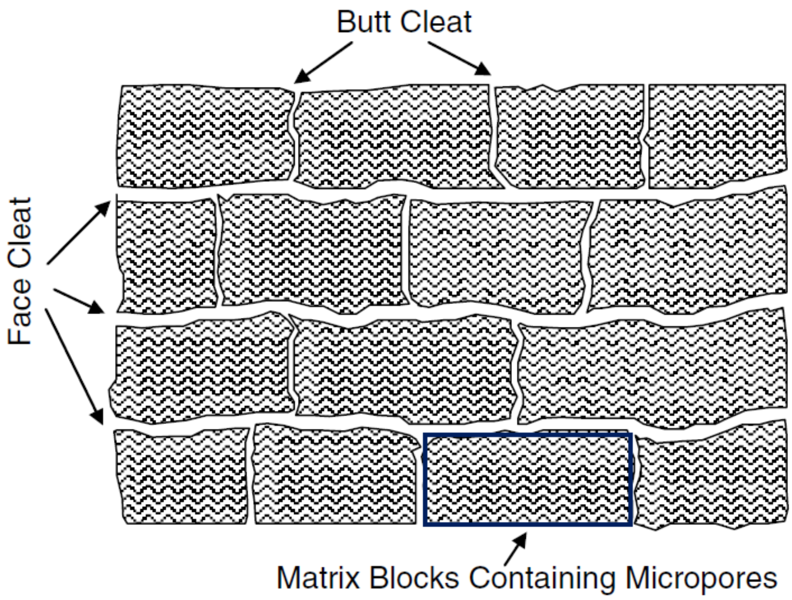

Fig. 1 Fracture system in coal bed methane reservoirs (Harpalani, 1999)

Fracture system in CBM reservoirs is saturated with water while gas is mainly stored as an adsorbed phase on the internal surface area of the coal. Only a negligible amount of gas is available as free gas in the cleat system (Gray, 1987).

Gas migration in CBM reservoirs consists of three different stages (Harpalani, 1990):

1. Gas desorption from coal surface:

   In dewatering stage, by producing water from the reservoir, reservoir pressure decreases. When reservoir pressure drops below adsorption/desorption pressure, gas molecules start to desorb from the coal surface and accumulate in micropores in the coal matrix (Fig. 2-a)

2. Gas diffusion through the matrix toward the fracture system:

   In this stage, accumulated desorbed gas molecules diffuse throughout the coal matrix into the cleat system. Since coal matrix permeability is usually 8 orders of magnitude lower than fracture permeability (Gamson et al., 1993), fluid movement in the coal matrix is described by the Fick's Law (Fig. 2-b).

3. Gas movement through the cleat network to the wellbore:

   In the last stage, gas flow in the fracture system toward the wellbore is governed by the Darcy flow (Fig. 2-c).

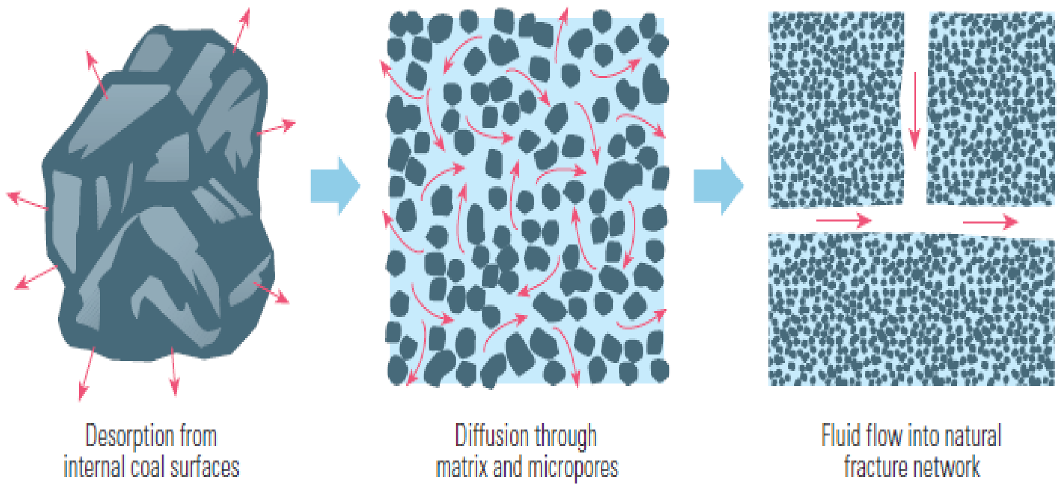

Fig. 2 Gas migration mechanisms in coal bed methane reservoirs (Reeves and Pekot, 2001)

2.3 Coal permeability

Permeability is an important parameter describing water/gas flow in coal bed methane reservoirs. Coal, the same as other naturally fractured reservoirs, shows a strong difference between fracture permeability and matrix permeability. Matrix permeability in CBM reservoirs is in the range of μD to nD, while cleat permeability is in the range of 0.1 to 100 mD (Palmer, 2010). However, in contrast with other naturally fractured rocks, in them matrix permeability often dominates reservoir performance; matrix permeability in coals has an insignificant effect on fluid flow. Thus, permeability of a coalbed is proportional to its cleat system properties (Palmer, 2009; Ried et al., 1992; Sparks et al., 1995).

Permeability of coal reservoirs changes as pressure declines during production. This change in permeability is caused by deformation of the matrix and fractures (Palmer, 2009). Permeability of CBM reservoirs, the same as other naturally fractured reservoirs, is a function of effective stress. Experimental and field studies show that as the effective stress increases the permeability decreases exponentially (Enever and Henning, 1997; Seidle et al., 1992; Somerton et al., 1975; Sparks et al., 1995). Another unique parameter which effects the permeability of CBM reservoirs is matrix deformation due to gas desorption/adsorption. This matrix deformation due to shrinkage/swelling strain leads to a geomechanical response changing the coal permeability (Pan and Connell, 2012). Therefore, permeability reduction with effective stress is counteracted by matrix shrinkage due to gas desorption (Gray, 1987). Hence, reservoir permeability declines initially during gas production due to decreasing pore pressure and consequently increasing effective stress, and then rebounds as matrix shrinkage effects dominate over the cleat compression.

A number of analytical coal permeability models have been developed during past 25 years including effective stress and matrix shrinkage/swelling effects. “Palmer and Mansoori” (Palmer and Mansoori, 1998) and “Shi and Durucan” (Shi and Durucan, 2004) models are the two most popular permeability models for CBM reservoirs. These models assume matchstick like geometry for the coal matrix and cleat system (Fig. 3). They also assume the reservoir is under uniaxial strain conditions, meaning that the coal matrix doesn’t deform in the horizontal plane, and the overburden stress remains constant.

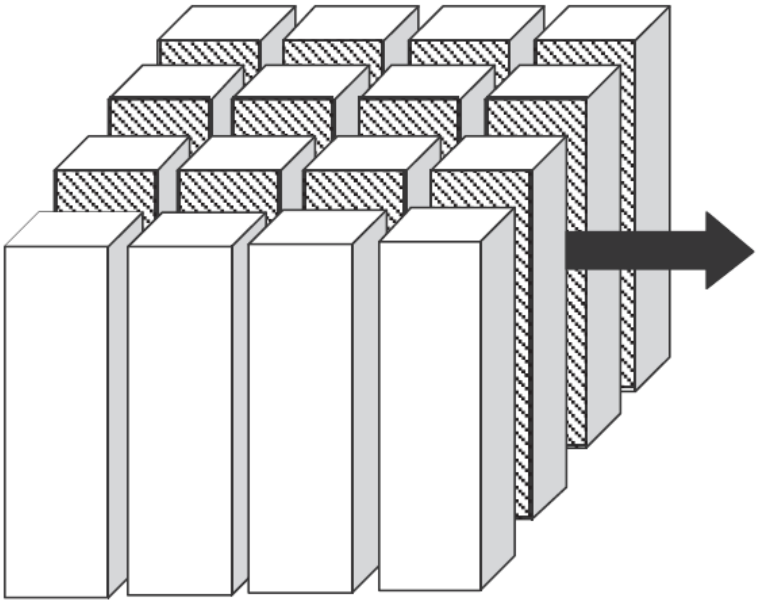

Fig. 3 matchstick geometry of coal matrix and cleat system in col bed methane reservoirs (Harpalani, 1999)

2.3.1 Palmer and Mansoori model

Palmer and Mansoori introduced a new model to express the changes in porosity for uniaxial strain condition (Palmer and Mansoori, 1998) :

$$\frac{\emptyset}{\emptyset_0} = \left(1 + c_f(p - p_o) + \varepsilon_L \left(\frac{K}{M} - 1\right)\left(\frac{p}{p_L + p} - \frac{p_o}{p_L + p_o}\right)\right) \qquad (1)$$

$\emptyset$	porosity at pressure p
$\emptyset_0$	initial porosity
c_f	pore volume compressibility
p	pressure
p_o	initial pressure
p_L	Langmuir pressure
ε_L	maximum matrix shrinkage strain
K	bulk modulus
M	axial modulus

Assuming that cleat permeability is proportional to the cube of cleat porosity (McKee, C.R., 1987):

$$\frac{k}{k_0} = \left(\frac{\emptyset}{\emptyset_0}\right)^3 \tag{2}$$

These authors proposed the following permeability model:

$$\frac{k}{k_0} = \left(1 + c_f(p - p_o) + \varepsilon_L\left(\frac{K}{M} - 1\right)\left(\frac{p}{p_L + p} - \frac{p_o}{p_L + p_o}\right)\right)^3 \tag{3}$$

where k is cleat permeability at pressure p and k_0 is initial cleat permeability.

In this model the changes in permeability are calculated as functions of elastic moduli, initial porosity, sorption isotherm parameters, and pressure drawdown.

2.3.2 Shi and Durucan permeability model

Shi and Durucan proposed another model for coal permeability based on the changes in effective horizontal stress instead of porosity (Shi and Durucan, 2004):

$$\frac{k}{k_0} = e^{-3c_f}(\sigma_e - \sigma_{e0}) \tag{4}$$

$$\sigma_e - \sigma_{e0} = -\frac{\nu}{1-\nu}(p - p_o) + \frac{E\varepsilon_l}{3(1-\nu)}\left(\frac{p}{p + p_L} - \frac{p_o}{p + p_L}\right) \tag{5}$$

k	permeability at pressure p
k_0	initial permeability
c_f	cleat volume compressibility
σ_e	effective horizontal stress
σ_{e0}	in-situ effective horizontal stress

p	pressure
p_o	initial pressure
p_L	Langmuir pressure
ε_l	maximum matrix shrinkage strain
v	Poisson's ratio
E	Young's modulus

2.4 Improved coal bed methane production techniques

As the majority of CBM reservoirs have low productivity index, some enhance production techniques have been applied to improve gas production from these reservoirs. The main stimulation technique in CBM reservoirs is hydraulic stimulation by injection fluid into a wellbore at high pressure. This fluid acts as the driving force to increase the conductivity of the existing fractures (naturally fracture stimulation) or to initiate and propagate a new fracture (hydraulic fracturing). In order to keep either hydraulically induced fractures or naturally fractures open after stimulation, Small propped agents (proppant) are injected into the reservoir. These proppant particles keep coal fractures open during the production stage.

2.4.1 Hydraulic fracturing

Hydraulic fracturing is a stimulation technique to increase production rate by creating a high conductivity tunnel from reservoir to wellbore. The first hydraulic fracturing stimulation was conducted in the Hugoton gas field in 1947 (Economides and Martin, 2007). Since then, hydraulic fracturing treatment technique developed rapidly and has been successfully applied for stimulation of conventional reservoirs. This stimulation method played a key role in improving oil and gas production over the last decades (Economides and Martin, 2007).

However, the mechanism and design of hydraulic fracturing in naturally fractured reservoirs, like CBM reservoirs, are different from those in conventional reservoirs. The primary role of hydraulic fracturing in coal bed methane reservoirs is to create an improved connection of the natural fractures and cleat network to the wellbore (Johnson et al., 2002). The main well stimulation technique in CBM wells is the hydraulic fracturing, including the combined with horizontal wells. However, conventional hydraulic fracturing technique has some limitations during stimulation of natural fracture rocks like CBM reservoirs. Injecting fluid may divert into the natural fractures when a hydraulically induced fracture intersects natural fractures, causing short and non-continuous cracks instead of a single massive fracture. This may accelerate fluid leak-off, induce extremely complex fracture geometry and cause inefficient proppant transport (Rahman et al., 2002; Warpinski and Teufel, 1987). Hossain et al. (2000) concluded that existence of natural fractures in the non-preferred direction of fracture propagation creates fracture tortuosity and consequently needs higher treatment pressure which may lead to treatment failure. In addition to that, sometimes environmental and reservoir sealing restrictions as well as the lack of injectivity power prevent from well stimulation by hydraulic fracturing in unconventional reservoirs ((Holahan and Arnold, 2013).

2.4.2 Naturally fracture stimulation

During naturally fracture stimulation, the objective is to activate opening of existing natural fractures by hydraulic stimulation, instead of creating a single massive fracture (Hossain et al., 2002; Rahman et al., 2002; Riahi and Damjanac, 2013).

Permeability of a natural fracture system increases with injection of fluid at high pressure into naturally fracture system. During naturally fracture stimulation, different mechanisms can lead to permeability enhancement, including the following (Riahi and Damjanac, 2013):

- ✓ Opening of pre-existing fractures due to slip-induced dilation, this mechanism is referred to as hydro-shearing or shear dilation stimulation.
- ✓ Increasing the connectivity of fractures in the fracture system due to extension of the pre-existing fractures and network; and
- ✓ Opening of pre-existing fractures due to increasing the reservoir pressure or decreasing the effective stress (this mechanism is almost reversible; meaning that the open fractures are closed when pressure dissipates. Hence, in this approach, injected fluid often needs to be accompanied by proppant particles to keep fractures open after pressure reduction).

In shear dilation fracture stimulation technique, under appropriate stimulation pressure, the fracture surfaces slip to each other due to shear stress perturbation. The shear stress perturbation occurs due to fluid injection into the fracture at high pressure. This results in the offset of two rough surfaces facilitating a flow conduit for hydrocarbon between them (Hossain et al., 2002). Hence, permeability of natural fracture systems increases due to mismatches and asperities that are created as a result of displacement of fracture walls from their original position. Asperities on the rough fracture surfaces, which are created during injection, resist sliding back to their original position when fluid injection is ceased.

Rahman et al (2002) proposed a shear dilation stimulation model for prediction of average permeability and mean flow direction in a reservoir with known natural fracture characteristics. In their model, both fracture propagation and shear slippage of natural fractures are taken into account. Riahi and Damjanac (2013) introduced a two-dimensional model describing an interaction between hydraulic fracture and discrete fracture network. They performed a series of comparative studies to establish the effect of various in-situ parameters, including geometrical properties of the discrete fracture network (such as the level of connectivity and fracture size distribution) and operational parameters (such as injection rate) on fracture conductivity. They found out that, the fluid injection rate plays a major role in distributing the fluid between the hydraulically induced fractures and the discrete fracture network. They showed that, for a given injected volume, higher injection rates yield a greater shear-stimulated surface area in the fracture system, provided that pressure remain below the hydraulic fracturing pressure. While at pressure above the hydraulic fracturing pressure, the higher is the injection rate, the better is the propagation of hydraulically induced fracture; however, smaller shear dilation stimulation occurs in such fracture network.

2.5 Proppant placement

The main objective of hydraulic stimulation is increasing reservoir productivity by inducing high conductive paths from the reservoir to the wellbore. These high conductive paths are formed by injecting fluids at high pressure into the reservoir. However, the open paths may close after ceasing fluid injection and pressure drop in the propped fractures. To maintain the flow paths after decline of stimulating pressure, small rigid proppants are placed in the propped fractures. These proppant particles help to mitigate the effect of fluid pressure reduction on fracture conductivity during gas production (Economides and Martin, 2007).

During hydraulic fracturing treatment, fractures are filled with multi-layer proppant particles in a method known as frac and pack. Darin and Huitt (1960) showed that during hydraulic fracturing, larger permeability would be achieved where an induced fracture is propped by a partial monolayer of large-sized proppant particles compare with, if the fracture is fully packed with small-sized, multilayer proppants. This is because of the existence of open spaces around and between placed proppant particles in the propped fractures. The partial monolayer proppant placement can be used to stimulate the natural fracture system or complex secondary fracture network around the main hydraulic fracture in unconventional reservoirs (Fredd et al., 2000; Khanna et al., 2012). Low viscosity fracturing fluids (slick water) can penetrate the natural fractures easier and create a wider stimulation zone. In addition, slick water fracturing treatment is relatively low cost and non-destructive stimulation technique. However, the most significant shortcoming of the slick water fracturing technique is its inability to carry the conventional proppant particles deep into the formation. It is due to high density of conventional proppant particles which yields early proppant settlement.

To facilitate proppant movement in narrow fractures, ultra-lightweight proppants (ULWPs) have been developed (Brannon et al., 2004). Chambers and Meise (2005) reported a flied case study showing that by using ULWPs and low viscosity fracturing fluids, partial monolayer proppant placement in hydraulic fracturing is possible.

Other important parameters which play key roles in the fracture conductivity are concentration of the placed proppant particles and confining stress. Several laboratory studies have been performed, using different proppant types, to determine the effect of confining stresses and proppant concentration on the fracture conductivity (Brannon and Starks, 2008; Fredd et al., 2000; Gaurav et al., 2012; Kassis and Sondergeld, 2010; Parker et al., 2005). The use of waterfracs with low concentration of ULWP has met tremendous success (Brannon et al., 2004; Brannon and Starks, 2009; Chambers and Meise, 2005; Cramer, 2008).

Khanna et al. (2012) showed that there is an optimal proppant concentration in which the fracture conductivity of a partial monolayer reaches its maximum value at a certain value of confining stress. They pointed out that there are two competing factors affecting fracture conductivity: proppant concentration; and, fracture deformation. If proppant concentration is higher, the resistance to the flow is also higher and, consequently, the fracture conductivity is lower. Alternatively, if the proppant concentration is lower, the distance between proppant particles is higher and, consequently, there is an excessive rock deformation between the placed particles, which would decrease the fracture permeability. There is, therefore, an optimal concentration of proppant particles at which the maximum permeability of the fracture system can be achieved (Fig. 4). The authors developed a semi-analytical mathematical model to calculate conductivity of a fracture filled by a monolayer of proppant particles. Hertz contact theory was used to obtain the fracture opening profile as a function of the proppant concentration and the value of confining stress. They used computational fluid dynamics (CFD) package to determine conductivity of a deformed fracture.

Although several experimental and modelling studies have been perform to evaluate the performance of proppant particle placement in a given fracture, experimental study aiming the performance evaluation of proppant placement in naturally fracture systems is not available in the current literature to the best of our knowledge.

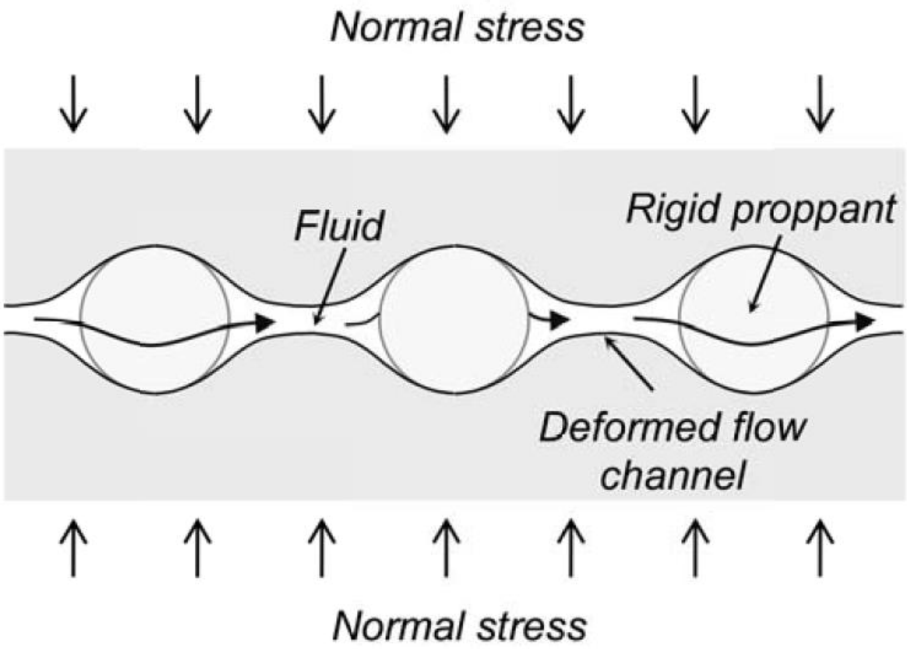

Fig. 4 Deformation of the cleat due to rock stresses and the additional tortuosity of the flow path due to the presence of the proppants (Khanna et al., 2013).

2.6 Electrostatic interactions

Particle attachment to rock surface and particle agglomeration may result in formation damage by forming external and internal cakes during proppant injection into a natural fracture system (Civan, 2007). The attraction of agglomerated proppant particles to a rock surface may cause the formation of external cake at fracture entrance and also an internal cake, preventing deep particle penetration into fractures (Bedrikovetsky, 2008; Bedrikovetsky et al., 2013; Kalantariasl and Bedrikovetsky, 2013; Kalantariasl et al., 2014a;

Kalantariasl et al., 2014b) . This could happen when inappropriate chemistry of particle based suspension is chosen. To determine favourable conditions for particle-particle and particle-rock repulsion, the total interaction potential energy between particles and rock surface are calculated according to Derjaguin-Landau-Verwey-Overbeek (DLVO) theory (Landau and Lifshitz, 1980; Verwey and Overbeek, 1999).The total interaction potential energy between injected particles and rock, V_{tot}, is a sum of interaction potential energies arising from the long-range London-van der Waals (LW) forces, V_{LW}, the short-range attractive/repulsive electrical double (EDL) layer, V_{EDL}, and short range Born repulsion (BR), V_B, forces as follows:

$$V_{tot} = V_{LW} + V_{EDL} + V_B. \tag{7}$$

The sphere-plate (s-p) and sphere-sphere (s-s) interactions are considered for interaction between particle-rock and particle-particle, respectively. The retarded LW interaction potential energies for the s-p and s-s interactions are calculated according to the following equations (Gregory, 1981):

$$V_{LW}^{s-p} = -\frac{A_{123} r_s}{6h^*}\left[1 - \frac{5.32h^*}{\lambda} ln\left(1 + \frac{\lambda}{5.32h^*}\right)\right]. \tag{8}$$

$$V_{LW}^{s-s} = -\frac{A_{123} r_s}{12h^*}\left[1 - \frac{5.32h^*}{\lambda} ln\left(1 + \frac{\lambda}{5.32h^*}\right)\right]. \tag{9}$$

where A_{123} is the Hamaker constant; λ is the characteristic wavelength of the interaction (Gregory, 1981); h^* is particle-surface (sphere-plate) separation distance.

The choice of the appropriate expressions for V_{EDL} depends on the Debye-Hückel parameter, κ, and the particle radius, r_s. The inverse to κ is equal to the EDL thickness. The Debye-Hückel constant is a function of the ionic solution strength (Elimelech et al., 1995). When the EDL thickness is significantly smaller than the particle sizes, the formulae for the electrical double layer energy V_{EDL} for sphere-plate and sphere-sphere interactions are (Elimelech et al., 1995):

$$V_{EDL}^{s-p} = \frac{128\pi r_s n_\infty k_B T}{\kappa^2}\gamma_1\gamma_2 e^{-\kappa h^*}, \tag{10}$$

$$V_{EDL}^{s-s} = \frac{64\pi r_s r_b\, n_\infty k_B T}{r_s \kappa^2}\gamma_1\gamma_2 e^{-\kappa h^*}, \tag{11}$$

where, n_∞ is bulk number density of ions; $k_B = 1.381\times10^{23}$ J/K is the Boltzmann constant; T=298.15 K is absolute temperature of the system; $\gamma_1 = \tanh\left(\frac{ze\zeta_p}{4k_BT}\right)$ and $\gamma_1 = \tanh\left(\frac{ze\zeta_c}{4k_BT}\right)$ are reduced surface potentials for particles and rock (Elimelech et al., 1995); ζ_p and ζ_c are zeta potentials for injected particles and rock, respectively; z is valence of a symmetrical electrolyte solution, e = 1.602×10^{-19} C is the elementary electric charge.

For a sphere-plate, V_B can be calculated according to the formula proposed by Ruckenstein and Prieve in (Ruckenstein and Prieve, 1976):

$$V_B = \frac{A_{123}{\sigma_c}^6}{7560}\left[\frac{8r_s+h^*}{(2r_s+h^*)^7} + \frac{6r_s-h^*}{{h^*}^7}\right], \tag{12}$$

where σ_c is the collision diameter.

The domination of the repulsive EDL and Born forces over the attractive LW forces results in the positive sign of V_{tot} for particle-particle and particle-coal matrix interactions (Sen et al., 1982). When particles are attracted to each other or to a porous matrix, the attractive LW forces dominate over EDL and Born forces, and the sign for V_{tot} changes to negative. Particles with sufficient energy can overcome the interaction potential energy barrier, approach the surface of a porous medium at a few nano-meters separation distance and be irreversibly attached to it in the primary energy minimum. The presence of a secondary energy minimum usually observed at larger separation distances can lead to particle detachment provided the particles have insufficient energy to escape (Kuznar and Elimelech, 2007).

In the current thesis, a new stimulation technique, called graded proppant injection, has been introduced in order to improve the permeability of natural fracture systems. The purpose of the proppant injection into a natural cleat is keeping it open during the production when pore pressure declines with time. Experimental studies and laboratory-based mathematical models are conducted for developing the technology. The proposed method has been applied to real case studies to predict the productivity enhancement during graded proppant injection.

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Chapter 3

Mathematical modelling of graded proppant injection in coal bed methane reservoirs

3.1 Stimulation of the natural fracture system by graded proppant injection.

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Name of Principal Author	Aditya Khanna		
Contribution to the Paper	Problem formulation, Derivation of the mathematical model, Writing the manuscript		
Signature		Date	8.12.2014

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Signature		Date	15/01/2015

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Contribution to the Paper	Supervised development of work, help in data interpretation, manuscript review and assessment		
Signature		Date	15/01/2015

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3.2 Stress-based mathematical model for graded proppant injection in coal bed methane reservoirs.

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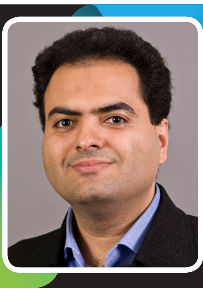
STRESS-BASED MATHEMATICAL MODEL FOR GRADED PROPPANT INJECTION IN COAL BED METHANE RESERVOIRS



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ABSTRACT

A technology called graded proppant (propping agent) injection that consists of the injection of proppant particles, with increasing sizes and decreasing concentrations, into a naturally fractured reservoir results in deeper percolation of the particles into the natural fracture system, and thus expansion of the stimulated reservoir area. The placement of graded proppant particles keeps the fractures open, even after pressure decline due to production. There is, therefore, an enhancement in the well productivity. This proposed technology could be used to improve the productivity of CSG wells and other unconventional resources; for example, in shales, tight gas, and geothermal reservoirs.

In this peer-reviewed paper, a mathematical model for well injectivity/productivity was developed for graded particle injection in a vertical well, lying at the centre of a circular drainage area. The model is based on an analytical solution of the quasi 1D problem of coupled axisymmetric fluid flow and geomechanics. Explicit analytical equations were derived for stress, and pressure and permeability distributions, as well as for the well index during injection and production. Results of previous computational fluid dynamic studies were used to determine the hydraulic resistance resulting from proppant plugging in the fractured system.

An optimal stimulation radius was identified, which resulted in the highest increment in the productivity index due to the application of graded proppant injection technology. The model was subsequently used for a sensitivity analysis using field data. The results showed that the productivity index increased more than four times by the application of this technology.

KEYWORDS

Coal seam gas, stimulation, graded proppant injection, natural fracture system, productivity index, stress, permeability, mathematical modelling.

INTRODUCTION

CSG is one of the world's fastest growing unconventional resources. Although CSG has many benefits compared with the traditional coal-burning power stations, and provides a much cleaner energy, it has some economic drawbacks. One of the most important problems associated with these reservoirs is their low production rate, which is due to their relatively low permeability. To achieve cost-effective production from CSG reservoirs, therefore, new techniques for enhancing permeability must be developed (Palmer, 2010).

A unique characteristic of naturally fractured rocks (including coal seams) is that their permeability is sensitive to pressure and stress. Pressure decline during production—which results in the deformation of the matrix and fractures—therefore, leads to significant variations in the permeability (Palmer, 2009). As a result, absolute permeability in these reservoirs should always be stated along with the pressure and stress conditions corresponding to the measurement.

Somerton et al (1975) reported that in laboratory experiments the permeability of fractured media depends not only on the number and width of the fractures, but also on the effective stress. Harpalani and Schrufnagel (1990) also had the same results in laboratory experiments. In addition, they found that for adsorbing gases, permeability is also influenced by gas adsorption/desorption. Han and Dusseault (2003) developed a general analytical method for stress-dependent porosity and permeability by coupling geomechanic and fluid flow in unconsolidated or weakly consolidated reservoirs. A number of analytical models have also been developed to describe this change in permeability for coal bed methane (CBM) reservoirs including the influence of effective stress and coal sorption (Gray, 1987; Seidle and Huitt, 1995; Palmer and Mansoori, 1998; Gilman and Beckie, 2000; Pekot and Reeves, 2003; Shi and Durucan, 2004, 2005; Cui et al, 2007; Wang et al, 2009; Connell et al, 2010; Pan and Connell, 2012).

The Palmer and Mansoori model and the Shi and Durucan model are the two most popular models, widely used in reservoir simulation. These models assume matchstick-like geometry for the coal matrix and cleat system. They also simplify the geomechanical processes by assuming the uniaxial strain conditions, which means that the matrix does not deform in the horizontal plane and the overburden stress remains constant (Connell et al, 2010). These conditions, however, may not always be satisfied in the reservoir, and are difficult to replicate in the laboratory (Connell et al, 2010; Durucan and Edwards, 1986). Pan et al (2010) presented a method to measure coal permeability under the tri-axial stress conditions in the laboratory. Connell et al (2010) from the same group developed a new permeability model validated by their previous experimental results for the permeability behavior under tri-axial conditions.

As mentioned above, during gas production from a coal seam reservoir, the fluid pressure in the cleat system reduces, this has a negative impact on gas flow and decreases reservoir permeability during production (Palmer, 2009). To keep these fractures open, even after pressure decline to prevent permeability decrement, small rigid proppant particles can be injected into the cleat system. This not only increases the initial production rates by enhancing permeability, but also helps to mitigate the effect of fluid pressure reduction on permeability during production. Traditionally, fractures are created hydraulically in reservoirs (hydraulic fracturing) and then filled with proppant particles in a method known as frac and pack. Many models exist in literature to describe the fluid flow through these created fractures (Economides and Nolte, 2000; Economides et al, 2002; Economides and Martin, 2007). Darin and Huitt (1960) showed that during hydraulic fracturing in cases where an induced fracture is propped by a partial monolayer of large-sized proppant particles, larger permeability would be reached than the situation where the fracture is fully packed with small-sized, multilayer proppants. Different studies have also been done on the improvement of permeability in natural fracture systems. Hossain et al (2002) and Rahman et al (2002) proposed a shear dilation stimulation model in which the permeability of natural fracture systems increases during fluid injection. This is because of mismatches and asperities that are created due to the displacement of fracture walls out of their original position. This shear slippage of two rough fracture surfaces dilates an aperture normal to the fracture surface. Asperities on the rough fracture surfaces, which are created during injection, resist sliding back to their original position when injection is ceased. Shear dilation, therefore, significantly decreases the requirement for proppant injection to keep fractures open after stopping the injection.

There are a few models to describe fluid flow in cleats filled with graded proppant. Khanna et al (2012a, 2012b) and Bedrikovetsky et al (2012) proposed a new technology for graded proppant injection in natural fracture systems. They found that there are two competing factors affecting fracture system conductivity: proppant concentration; and, fracture deformation. If the concentration is higher, the resistance to the flow is also higher and, consequently, the permeability is lower. Alternatively, if the concentration is lower, the distance between the particles is higher and, consequently, there is excessive rock deformation between the particles, which would decrease the permeability. There is, therefore, an optimal concentration of proppant particles in which the maximum permeability of the fracture system is found. This model is described briefly in the appendix.

This paper describes an analytical, stress-based mathematical model that explains fluid flow and rock deformation. It also accounts for the injection and production of fluid into a coal seam by the coupling of flow and geomechanical models. The model is capable to specify stress, pressure and permeability distributions around the wellbore. Models for both the injectivity and productivity indexes are also provided. These include graded proppant placement for the injection and production of fluid at the dewatering stage (the gas production stage has not been considered). By applying the effects of changing proppant concentration and fracture deformation, a critical stimulation radius is introduced beyond which proppant placement decreased the permeability. This critical stimulation radius is, therefore, the maximum radius for achieving the highest productivity index. The model was applied to a real field and the effect of injection pressure on the well productivity index and stimulation radius is presented. The results show that the productivity index increased by more than four times due to applying this technology.

GRADED PROPPANT INJECTION

Traditionally, wells in naturally fracture reservoirs have been stimulated by creating large fractures and filling them with mono-sized (same-sized) proppant particles during hydraulic fracturing. This technique, however, has some drawbacks. Since the size of the proppant particles determines the stimulation radius, finer proppants would penetrate deeper into the reservoir and maximise this stimulation radius. Alternatively, in the near wellbore area, fracture widths are higher; hence, bigger proppants can keep the fractures open better than finer ones. In other words, small mono-sized proppants provide a non-optimal near wellbore permeability, and large mono-sized proppants lead to a non-optimal stimulation radius. In this paper, a new technique that involves a graded proppant injection in the already existing natural fracture network is proposed. In this approach, an initial injection of finer proppants is performed to maximise the stimulation radius, followed by injection of bigger sized proppants that would provide maximum permeability to the wellbore region.

The purpose of this new technique is to stimulate the existing natural fractures instead of creating new fractures. To have the best performance, therefore, the width of the existing fractures needs to be increased as much as possible. At a first look, the injection of small mono-sized proppants would not enlarge the natural fractures. If this injection is, however, followed by the injection of bigger size proppants, the fractures are filled with a partial monolayer of proppants with decreasing sizes away from the wellbore (Fig. 1). This process results in the fracture aperture of the same proppant diameters and the proppants are also spaced apart from each other (i.e., they are not touching each other).

MATHEMATICAL MODEL

Modelling assumptions

To determine the permeability and opening of the cleat network during the injection of fluid into the reservoir, several modelling assumptions have been made. The following assumptions are regarded to both the cleat network and injection fluid:

1. Horizontal stresses acting on the reservoir are equal in all directions (isotropic) and, therefore, in the horizontal plane the problem can be considered axisymmetric.
2. The formation is elastic and no failure occurs.
3. The reservoir is vertically constrained due to the overburden formations and can be considered to be under a plane strain situation.
4. The behavior of the coal matrix is assumed to be elastic during both the injection and production periods.
5. Additional fractures are not created during the injection process, and only the natural fractures are stimulated (the injection pressure is below the breakdown pressure).
6. The reservoir permeability is isotropic, and Darcy's law can be used to describe the fluid flow through the cleat network.

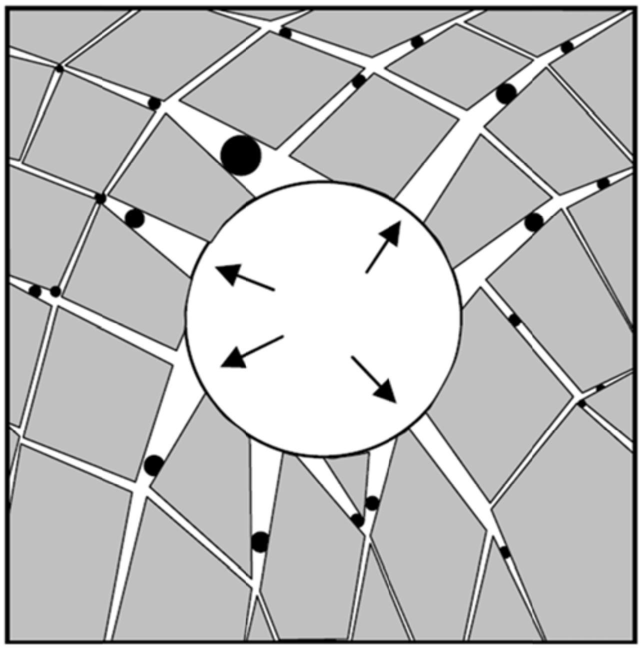

Figure 1. Graded proppant placement.

7. The coal seam is thin; therefore, vertical flow can be neglected.
8. The injection fluid is incompressible.
9. The pressure distribution is steady-state as the time of propagation of the elastic pressure wave is negligibly smaller than the time of injection.
10. Shrinkage of the coal caused by gas desorption, which takes place due to a reduction in reservoir pressure, is neglected.
11. The proppants fill the cleat network as a partial mono-layer. This means that the diameter of the proppants is equal to the width of the cleat opening during injection, and that the individual proppant particles are not touching each other.
12. Biot's coefficient (α) is equal to 1 (α=1).

Fluid injection model

To determine the permeability and cleat opening during fluid injection into the naturally fractured coal system, the distribution of pressure must first be determined. Assuming isotropic permeability, the distribution of pressure in the reservoir can be found using Darcy's law (Eq. 1), where permeability is a function of the formation stress and pressure.

$$q=-\frac{2\pi rk(\sigma_{avg},p)}{\mu}\frac{\partial p}{\partial r} \tag{1}$$

The permeability function in Equation 1 can be described by the permeability-pressure relationship in Equation 2 (Connell et al, 2010). This permeability model considers the tri-axial strain and stress conditions in the reservoir and is a function of the average stress defined in Equation 3. The sorption terms has been neglected for fluid injection.

$$k(\sigma_{avg},p)=k_0\exp\left\{-3C_f\left((\sigma_{avg}-\sigma_{avg,0})-(p-p_{res})\right)\right\} \tag{2}$$

$$\sigma_{avg}=\frac{\sigma_r+\sigma_\varphi+\sigma_z}{3} \tag{3}$$

For an elastic isotropic formation, stress equilibrium and Hook's law in cylindrical coordinates (plain strain and axisymmetric assumption) are expressed by Equations 4 and 5a–5c, respectively.

$$\frac{\partial\sigma_r}{\partial r}=\frac{\sigma_\varphi-\sigma_r}{r} \tag{4}$$

$$\varepsilon_r=\frac{1}{E}(\sigma_r-\upsilon(\sigma_\varphi+\sigma_z)-(1-2\upsilon)\alpha p) \tag{5a}$$

$$\varepsilon_\varphi=\frac{1}{E}(\sigma_\varphi-\upsilon(\sigma_r+\sigma_z)-(1-2\upsilon)\alpha p) \tag{5b}$$

$$\sigma_z=\upsilon(\sigma_r+\sigma_\varphi)+(1-2\upsilon)\alpha p \tag{5c}$$

In Equations 4 and 5a–5c, α is the effective stress coefficient (or Biot's constant) defined in $\sigma^{eff}=\sigma-\alpha p$ and varies from φ (porosity) to 1, depending on the rock lithology and state of consolidation. Usually, for unconsolidated or weakly consolidated sand, α is approximately equal to 1 (Han and Dusseault, 2003). By substituting Equation 5c into Equations 5a and 5b, radial and angular strains are found as functions of radial stress, angular stress and pressure in Equations 6a and 6b.

$$\varepsilon_r=\frac{1+\upsilon}{E}\left((1-\upsilon)\sigma_r-\upsilon\sigma_\varphi-(1-2\upsilon)\alpha p\right) \tag{6a}$$

$$\varepsilon_\varphi=\frac{1+\upsilon}{E}\left((1-\upsilon)\sigma_\varphi-\upsilon\sigma_r-(1-2\upsilon)\alpha p\right) \tag{6b}$$

By assuming α=1, therefore, the permeability equation (Eq. 2) can be expressed as Equation 7.

$$k(\sigma_r,\sigma_\varphi,p)=k_0\exp\left\{-3C_f\left(\left(\frac{(1+\upsilon)(\sigma_r+\sigma_\varphi)+(1-2\upsilon)p}{3}-\frac{(1+\upsilon)(\sigma_{r,0}+\sigma_{\varphi,0})+(1-2\upsilon)p_{res}}{3}\right)-(p-p_{res})\right)\right\} \tag{7}$$

The radial and angular strains can also be expressed as a function of the radial displacement vector (u_r) for plane strain conditions (Eqs 8a and 8b).

$$\varepsilon_r=\frac{\partial u_r}{\partial r} \tag{8a}$$

$$\varepsilon_\varphi=\frac{u_r}{r} \tag{8b}$$

Radial strain can then be expressed as Equation 9.

$$\varepsilon_r=r\frac{\partial\varepsilon_\varphi}{\partial r}+\varepsilon_\varphi \tag{9}$$

Substituting Equations 6a and 6b into Equation 9 gives the second relationship between radial and angular stress (Eq. 10).

$$\frac{\sigma_r-\sigma_\varphi}{r}=(1-\upsilon)\frac{\partial\sigma_\varphi}{\partial r}-\upsilon\frac{\partial\sigma_r}{\partial r}-(1-2\upsilon)\frac{\partial p}{\partial r} \tag{10}$$

Finally, this results in the following system of three equations with three unknowns: radial (Eq. 11), and angular stresses (Eq. 12) and pressure (Eq. 13).

$$q=-\frac{2\pi rk_0}{\mu}\exp\left\{-3C_f\left(\left(\frac{(1+\upsilon)(\sigma_r+\sigma_\varphi)+(1-2\upsilon)p}{3}-\frac{(1+\upsilon)(\sigma_{r,0}+\sigma_{\varphi,0})+(1-2\upsilon)p_{res}}{3}\right)-(p-p_{res})\right)\right\}\frac{\partial p}{\partial r} \tag{11}$$

$$\frac{\partial\sigma_r}{\partial r}=\frac{\sigma_\varphi-\sigma_r}{r} \tag{12}$$

$$\frac{\sigma_r-\sigma_\varphi}{r}-(1-\upsilon)\frac{\partial\sigma_\varphi}{\partial r}-\upsilon\frac{\partial\sigma_r}{\partial r}-(1-2\upsilon)\frac{\partial p}{\partial r} \tag{13}$$

By solving this system of equations, Equations 14 and 15 for radial stress and angular stress, respectively, can be found, where A and B are integration constants.

$$\sigma_r = \frac{1}{r^2}\frac{(1-2\upsilon)}{(1-\upsilon)}\int_{r_w}^{r} rp(r)dr + \frac{B}{r^2} + A \tag{14}$$

$$\sigma_\varphi = -\frac{1}{r^2}\frac{(1-2\upsilon)}{(1-\upsilon)}\int_{r_w}^{r} rp(r)dr + \frac{(1-2\upsilon)}{(1-\upsilon)}p(r) - \frac{B}{r^2} + A \tag{15}$$

Applying the following boundary conditions from Equations 16 and 17 (Han and Dusseault, 2003) to Equation 14, and solving for the integration constants, gives formulas for A (Eq. 18) and B (Eq. 19).

$$r = r_w;\ p = p_w;\ \sigma_{r,eff} = 0 \tag{16}$$

$$r = r_e;\ p = p_0;\ \sigma_{r,eff} = \sigma_{h,eff} = \sigma_h - p_{res} \tag{17}$$

$$A = p_w - \frac{B}{r_w^2} \tag{18}$$

$$B = \frac{r_w^2 r_e^2}{r_e^2 - r_w^2}\left[p_w + \frac{1}{r_e^2}\frac{(1-2\upsilon)}{(1-\upsilon)}\int_{r_w}^{r_e} rp(r)dr - \sigma_h\right] \tag{19}$$

As the radial and angular stresses have now been found, the pressure distribution during injection into a coal seam can be determined by substituting Equations 14 and 15 into Darcy's law (Eq. 11) giving Equation 20.

$$\frac{q\mu}{2\pi k_0}\int_{r_e}^{r}\frac{1}{r}dr = \int_{p}^{p_{res}}\exp\left\{C_f\frac{(1+\upsilon)}{(1-\upsilon)}(p(r)-p_0)\right\}dp \tag{20}$$

Solving Equation 20 finally gives the pressure distribution during injection as a function of radius (Eq. 21). The stress equations as functions of radius can then be expressed as Equations 22 and 23.

$$p_{inj}(r) = p_{res} + \frac{1-\upsilon}{(1+\upsilon)C_f}\ln\left[1 - \frac{q\mu C_f}{2\pi k_0}\frac{(1+\upsilon)}{(1-\upsilon)}\ln\frac{r}{r_e}\right] \tag{21}$$

$$\sigma_r(r) = \frac{1}{r^2}\frac{(1-2\upsilon)}{(1-\upsilon)}\int_{r_w}^{r} r\left[p_{res} + \frac{1-\upsilon}{(1+\upsilon)C_f}\ln\left[1 - \frac{q\mu C_f}{2\pi k_0}\frac{(1+\upsilon)}{(1-\upsilon)}\ln\frac{r}{r_e}\right]\right] dr + \frac{B}{r^2} + A \tag{22}$$

$$\sigma_\varphi(r) = -\frac{1}{r^2}\frac{(1-2\upsilon)}{(1-\upsilon)}\int_{r_w}^{r} r\left[p_{res} + \frac{1-\upsilon}{(1+\upsilon)C_f}\ln\left[1 - \frac{q\mu C_f}{2\pi k_0}\frac{(1+\upsilon)}{(1-\upsilon)}\ln\frac{r}{r_e}\right]\right] dr + \frac{(1-2\upsilon)}{(1-\upsilon)}p(r) - \frac{B}{r^2} + A \tag{23}$$

By substituting the pressure and stress distributions (Eqs 21–23) into Equation 7, the permeability distribution can then found to be Equation 24. This permeability equation has been substituted into the permeability-cleat opening relationship in Equation 25 (Bear, 1972; Basniev et al, 1988) to find the cleat opening distribution during injection (Eq. 26).

$$k_{inj}(r) = k_0\left[1 - \frac{q_{inj}\mu C_f}{2\pi k_0}\frac{(1+\upsilon)}{(1-\upsilon)}\ln\frac{r}{r_e}\right] \tag{24}$$

$$\frac{k}{k_0} = \left(\frac{\phi}{\phi_0}\right)^3 = \left(\frac{h}{h_0}\right)^3 \tag{25}$$

$$h(r) = h_0\left(\frac{k(r)}{k_0}\right)^{\frac{1}{3}} = h_0\left(1 - \frac{q_{inj}\mu C_f}{2\pi k_0}\frac{(1+\upsilon)}{(1-\upsilon)}\ln\frac{r}{r_e}\right)^{\frac{1}{3}} \tag{26}$$

Injectivity and productivity indexes

Injectivity and productivity indexes characterise well performance during injection and production, which can be found as functions of rate and pressure difference (Eqs 27 and 28).

$$II = \frac{q}{p_w - p_{res}} \tag{27}$$

$$PI = \frac{q}{p_{res} - p_w} \tag{28}$$

By using the same mathematical procedure as the previous section, the pressure distribution during production (before stimulation) is found by Equation 29, and the permeability distribution is found by Equation 30. The initial productivity index is, therefore, determined by Equation 31, and the injectivity index is established by Equation 32. The dimensionless rates ε_{qinj} and ε_{qp} are defined by Equations 33a and 33b.

$$p_{pr}(r) = p_{res} + \frac{1-\upsilon}{(1+\upsilon)C_f}\ln\left[1 + \frac{q_{pr}\mu C_f}{2\pi k_0}\frac{(1+\upsilon)}{(1-\upsilon)}\ln\frac{r}{r_e}\right] \tag{29}$$

$$k_{pr}(r) = k_0\left[1 + \frac{q_{pro}\mu C_f}{2\pi k_0}\frac{(1+\upsilon)}{(1-\upsilon)}\ln\frac{r}{r_e}\right] \tag{30}$$

$$PI_0 = \frac{q_{pr}}{p_{res} - p_w} = \frac{q_{pr}}{\left[-\frac{1-\upsilon}{(1+\upsilon)C_f}\ln\left[1 + \frac{q_{pr}\mu C_f}{2\pi k_0}\frac{(1+\upsilon)}{(1-\upsilon)}\ln\frac{r_w}{r_e}\right]\right]} \tag{31}$$

$$I_0 = \frac{q_{inj}}{p_w - p_{res}} = \frac{q_{inj}}{\left[\frac{1-\upsilon}{(1+\upsilon)C_f}\ln\left[1 - \frac{q_{inj}\mu C_f}{2\pi k_0}\frac{(1+\upsilon)}{(1-\upsilon)}\ln\frac{r_w}{r_e}\right]\right]} \tag{32}$$

$$\varepsilon_{qinj} = \frac{q_{inj}\mu C_f}{2\pi k_0}\frac{(1+\upsilon)}{(1-\upsilon)} \tag{33a}$$

$$\varepsilon_{qp} = \frac{q_{pr}\mu C_f}{2\pi k_0}\frac{(1+\upsilon)}{(1-\upsilon)} \tag{33b}$$

Inside the proppant stimulated area, the fracture system permeability is less than the permeability, which is calculated without considering the effect of particle straining. A correction factor (f) is, therefore, introduced such that the fracture system permeability inside the proppant stimulated zone is $f\times k(r)$. This correction factor is a function of two dimensionless parameters: the dimensionless optimum particle packing aspect ratio (β); and, the dimensionless stress (σ/E). Khanna et al (2012a, 2012b) developed a methodology for finding these parameters based on computational fluid dynamics and Hertz theory. This methodology is described briefly in the appendix.

The injectivity/productivity indexes, therefore, change when proppants are introduced into the injection fluid. The permeability during the injection of proppant into the reservoir can be defined as Equation 34 where r_{st} is the stimulation radius by proppant placement. During injection, the hydraulic pressure keeps the fractures open; hence, the only decline in permeability is due to plugging of the cleats. The $f(\beta,0)$ dimensionless factor in this equation accounts for the reduction in permeability due to proppant plugging in the cleat network, and a similar factor $f(\beta,\sigma/E)$ is applied for the production case (Eq. 35). During production, this factor not only represents the effect of proppant plugging in the cleat network but also the closure and deformation of these cleats around the proppant. Beyond the proppant stimulated area, reservoir permeability during production is found by Equation 30. The complete equations for permeability in each radius of reservoir during injection and production are presented in Equations 34 and 35.

$$k_{inj}(r) = \begin{cases} f(\beta,0).k_{inj}(r) & r \le r_{st} \\ k_{inj}(r) & r > r_{st} \end{cases} \tag{34}$$

$$k_{pr}(r) = \begin{cases} f\left(\beta,\frac{\sigma}{E}\right).k_{inj}(r) & r \le r_{st} \\ k_{pr}(r) & r > r_{st} \end{cases} \tag{35}$$

Finally, the injectivity and productivity indexes accounting for the presence of proppant can be determined using the following formulas (Eqs 36 and 37) where it is assumed that the stimulation radius and the drainage radius are the same.

$$II_p = \frac{q_{inj}}{p_w - p_{res}} = \frac{2\pi k_0 f(\beta,0)\varepsilon_{qinj}}{\mu \ln\left(1+\varepsilon_{qinj}\ln\left(\frac{r_e}{r_w}\right)\right)} \tag{36}$$

$$PI_p = \frac{q_{pr}}{p_{res} - p_w} = \frac{2\pi k_0 f\left(\beta,\frac{\sigma}{E}\right)\varepsilon_{qinj}}{\mu \ln\left(1+\varepsilon_{qinj}\ln\left(\frac{r_e}{r_w}\right)\right)} \tag{37}$$

The productivity index described above assumes that proppants fill the cleats up to the drainage radius. Based on Equation 35, the permeability formula after stimulation—in the stimulated area—is $f(\beta,\sigma/E)\times k_{injr}$. But the permeability formula, before stimulation, and in the non-stimulated zone, is $k_{pr}(r)$ from Equation 30. When the permeability due to proppant injection $f(\beta,\sigma/E)\times k_{injr}$ is higher than the original permeability $k_{pr}(r)$, it shows that proppant injection has improved the permeability. If, however, permeability in the proppant invaded zone is lower than the original permeability (where the flow resistivity effect, due to proppant placement, is dominant compared to the increase in fracture aperture), proppant injection decreases permeability in this area. There is, therefore, a critical radius ahead of which proppant placement decreases the permeability. This critical radius is called the stimulation radius and is found by Equation 38.

$$k_{inj}(r_{st})f\left(\beta,\frac{\sigma}{E}\right) = k_{pr}(r_{st}) \rightarrow r_{st}$$
$$= r_e \exp\left\{\frac{\left(f\left(\beta,\frac{\sigma}{E}\right)-1\right)}{\frac{\mu C_f}{2\pi k_0}\frac{(1+\upsilon)}{(1-\upsilon)}\left[f\left(\beta,\frac{\sigma}{E}\right)q_{inj}+q_{pr}\right]}\right\} \tag{38}$$

The productivity index is, therefore, found by Equation 39.

$$PI = \frac{q_{pr}}{\Delta p_t} = \frac{q_{pr}}{\Delta p_{st} + \Delta p_{nst}} \tag{39}$$

In Equation 39: Δp_{st} is the pressure gradient in the stimulated area, which has been filled by proppant; and, Δp_{nst} is the pressure gradient in the non-stimulated area. Δp_{st} and Δp_{nst} are found by applying the production permeability formula (Eq. 35) into Equation 1, giving Equations 40 and 41.

$$\Delta p_{st} = \frac{q_{pr}\mu}{2\pi k_0 f\left(\beta,\frac{\sigma}{E}\right)}\int_{r_w}^{r_{st}}\frac{\partial r}{r\left[1-\varepsilon_{qinj}\ln\left(\frac{r}{r_{st}}\right)\right]}$$
$$= \frac{q_{pr}\mu}{2\pi k_0 f\left(\beta,\frac{\sigma}{E}\right)}\frac{\ln\left[1-\varepsilon_{qinj}\ln\left(\frac{r_w}{r_{st}}\right)\right]}{\varepsilon_{qinj}} \tag{40}$$

$$\Delta p_{nst} = -\frac{1-\upsilon}{(1+\upsilon)C_f}\ln\left[1+\varepsilon_{qpr}\ln\frac{r_{st}}{r_e}\right] \tag{41}$$

Results and discussion

In this section, the derived mathematical model is applied to a real coal seam field case to show the ability of the new technology in increasing the productivity index.

The field case studied is the Southern Qinshui Basin. It is located in the Shanxi Province of Central China and is one of the world's largest CBM reservoirs with a gas reserve of 3.96 trillion m^3. The Southern Qinshui Basin has become China's first commercial CBM reservoir. The basin refers to a region that includes Changzhi, Gaoping, Jincheng, Yangcheng, Qinshui, and Anze in the southeast of Shanxi Province, and measures approximately 120 km north to south and 80 km east to west, with an area of about 7,000 km^2 (Meng et al, 2011).

The common reservoir parameters for the Southern Qinshui Basin, which are used in this model, are summarised in Table 1.

Based on Equation 24, the higher the injection rate, the higher the permeability is. As the target is to stimulate the existing

Table 1. Parameters used in the model.

Parameter	Units	Values
k_0	md	0.8554
E	MPa	900
v	–	0.31
Depth	m	428
σ_h	MPa	6.5
σ_H	MPa	10
σ_v	MPa	12
P_{res}	MPa	6.87
T	MPa	0.48
C_f	MPa^{-1}	0.588

fracture system (not to create new fractures), however, the injection pressure cannot be higher than the fracture breakdown pressure, which is given by Equation 42.

$$p_b = 3\sigma_h - \sigma_H - p_{res} + T \qquad (42)$$

In Equation 42, T is the tensile strength, σ_h and σ_H are minimum and maximum horizontal stresses, respectively, and P_{res} is the reservoir pressure. Figure 2 shows permeability distributions during injection and production before and after stimulation, where injection pressure is 90% of the fracture breakdown pressure.

As can be seen in Figure 2, during the fluid injection without particle, the maximum permeability distribution is achieved. During suspension injection and fluid production (the dewatering stage), however, the permeability distributions decrease by $f(\beta,0)$ and $f(\beta,\sigma/E)$ times, respectively.

The dimensionless optimum particle packing aspect ratio (β), dimensionless stress (σ/E), and permeability correction factor ($f(\beta,\sigma/E)$) are calculated by the method described in the appendix.

As illustrated in Figure 2, there is a critical radius ahead of which proppant placement decreases the production permeability, because where the radius is greater than the critical radius, the effect of flow resistivity due to proppant placement is dominant compared to the increment in the opening of the fractures. Proppant placement, therefore, decreases the permeability in this area. This critical radius is the stimulation radius. This means that by placing the particles up to this radius, the maximum increase in permeability is achieved.

In Figure 3, pressure distribution in the dewatering stage is presented for three different scenarios: pressure distribution without stimulation; pressure distribution for full proppant placement ($r_{st}=r_e$); and, pressure distribution for partial proppant placement($r_{st}<r_e$). As seen in Figure 3, the maximum pressure gradient is for the non-stimulated scenario, and the minimum pressure gradient is for the partial proppant placement scenario. It can be clearly seen that the pressure distribution curve for the non-stimulated scenario is above the full proppant placement scenario up to the near wellbore radii. In the near wellbore area, however, the pressure distribution curve for the non-stimulated scenario drops significantly and falls below the pressure distribution for the full proppant placement scenario. The reason is that in the region far from the wellbore, a higher pressure decline is observed in the pressure distribution

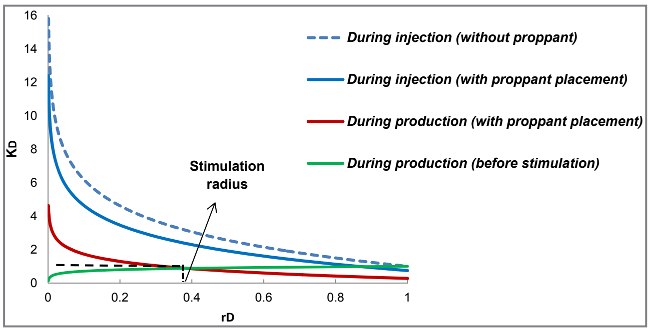

Figure 2. Permeability distribution during injection and production for maximum injection pressure (P_{inj}=0.9Pb).

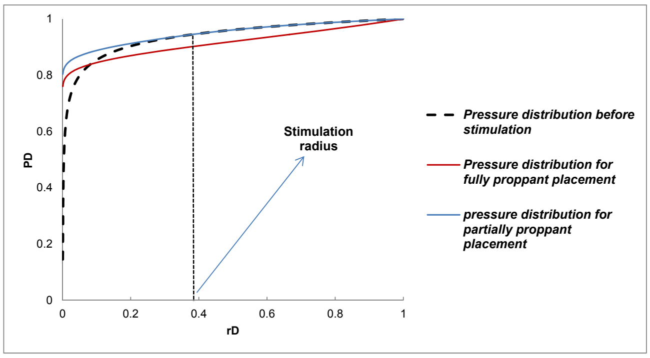

Figure 3. Pressure distribution during production.

for the full proppant placement scenario compared with the pressure distribution for the non-stimulated one. This is because of the negative effect of proppant placement on the permeability in this area. Proppant placement, however, significantly increases the permeability of the reservoir around the wellbore for a full proppant placement scenario compared to the non-stimulated one. Hence, the total pressure gradient for a full proppant placement scenario is much lower than that for the non-stimulated reservoir. For the partial proppant placement scenario, pressure distribution is the same as that in the non-stimulated one (above the pressure distribution for the full proppant placement scenario) up to the stimulated radius. From then on, the permeability starts increasing due to the arrangement of proppants in the fracture system.

In Figure 4, permeability distributions are presented for both partial and full proppant placement scenarios in different injection pressures. It is illustrated that the higher the injection pressure is, the higher the stimulation radius and the higher the permeability in the stimulated area are.

In Figure 5, stimulation radii are presented for different injection rates. It can be seen that the higher the injection rate is, the higher the stimulation radius is.

In Figure 6, the normalised productivity indexes (stimulated productivity index divided by non-stimulated productivity index) are presented for both the partial and full proppant placement scenarios in different injection pressures. It can be observed that the higher the injection pressure (injection rate) is, the higher the productivity index is. It can also be seen that for all injection pressures, the productivity index for the partial proppant placement scenario is higher than that for the full proppant placement one.

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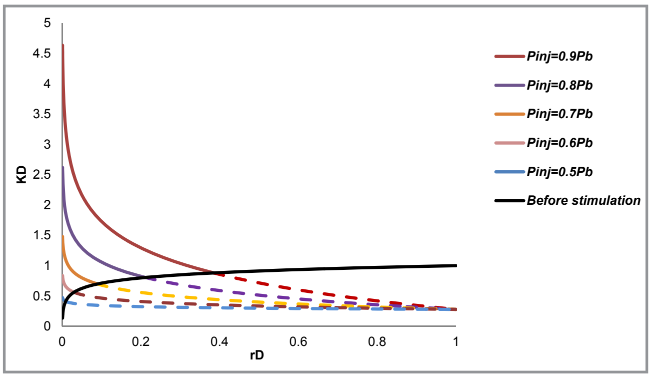

Figure 4. Production permeability distribution for different injection pressures. (The solid lines are for partial proppant placement, and the dashed lines represent full proppant placement).

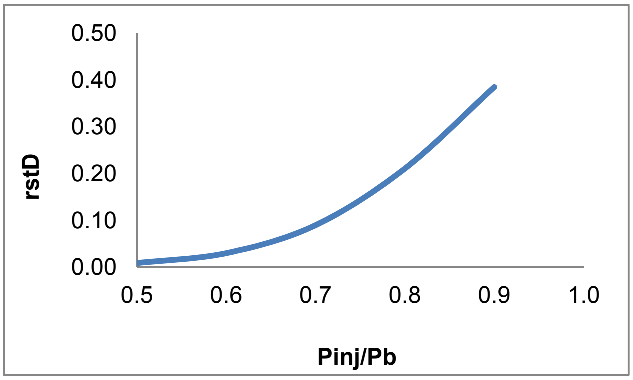

Figure 5. Stimulation radius versus injection pressure.

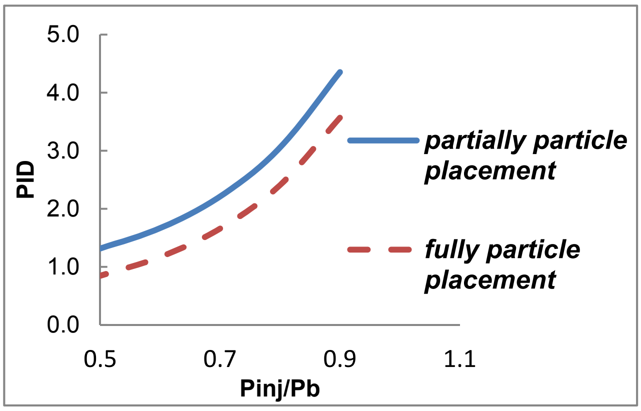

Figure 6. The productivity index versus injection pressure.

CONCLUSIONS

1. An analytical, stress-based mathematical model describing fluid flow and rock deformation has been developed for graded proppant injection using a coupled flow and geomechanical model.
2. The most influential parameter affecting the well productivity index during graded proppant injection is injection pressure (injection rate). A higher injection pressure results in greater opening of the cleats and increases the stimulation radius. Finally, it leads to an increase in the productivity index.
3. As the technique aims to stimulate the existing fracture systems (without inducing new fractures), the maximum injection pressure must be lower than the reservoir breakdown pressure.
4. For each injection pressure (rate) there is a critical stimulation radius ahead of which proppant placement decreases the production permeability. This occurs because, where the radius is larger than the critical stimulation radius, the effect of flow resistivity—due to proppant placement—is dominant compared to increasing the opening of the fractures. Proppant placement, therefore, decreases the permeability in this area.
5. The results for the application of the model to a field case showed an increase of more than four times in the productivity index.

APPENDIX

Khanna et al (2012a, 2012b) showed that the hydraulic resistance in the stimulated natural fractures results from the following two competitive factors:

1. the additional tortuosity due to the presence of the particles; and,
2. deformation of propped fractured channels during production due to rock stresses.

There are, therefore, two competitive factors affecting fracture system conductivity: proppant concentration; and, fracture deformation. If the concentration is higher, the resistance against the flow is higher and, consequently, the permeability is lower. On the other hand, if the concentration is lower, the distance between the particles is higher and, consequently, the rock deformation between the particles is higher. This deformation would decrease the fracture opening. Hence, there is an optimal concentration of proppant for the maximum conductivity of the fracture system to be reached (Fig. 7).

Khanna et al (2010a, 2012b) studied the effect of proppant placement in the cleat on the permeability using computational fluid dynamic methods. In these models, a dimensionless particle packing aspect ratio (β) was introduced. This parameter represents the ratio between the diameter of the proppant and the distance between the centres of two adjacent proppants. Then they introduced a hydraulic resistance correction factor (Eq. 43) as a function of β. The reduction of cleat permeability due to proppant placement can be found through multiplying the permeability by the hydraulic resistance correction factor, as illustrated by Figures 8 and 9.

$$f(\beta,0)=\frac{0.3197\beta^2-0.7181\beta+0.4057}{\beta^2-0.4789\beta+0.4048} \tag{43}$$

They also studied the effect of cleat deformation on cleat permeability using finite element analysis and Hertz theory. The combined effect of the proppant placement and cleat

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deformation can be seen in Figure 9, in which the hydraulic resistance correction factor is a function of dimensionless particle packing aspect ratio and dimensionless stress. Dimensionless stress is the normal stress to the cleat, which causes the deformation of the cleat, divided by the coal modulus of elasticity.

Figure 9 shows that the optimal proppant aspect ratio (β) must be determined for each state of stress as it is a function of the reservoir stress. Figure 10 shows how the optimal proppant aspect ratio (β) is found in each dimensionless stress. Then, by putting this optimal proppant aspect ratio (β) in Figure 9, the value for the correction factor is found.

Detailed calculations of optimum proppant concentration based on Hertz contact theory and computational fluid dynamic studies are presented by Khanna et al (2012a, 2012b) and Bedrikovetsky et al (2012).

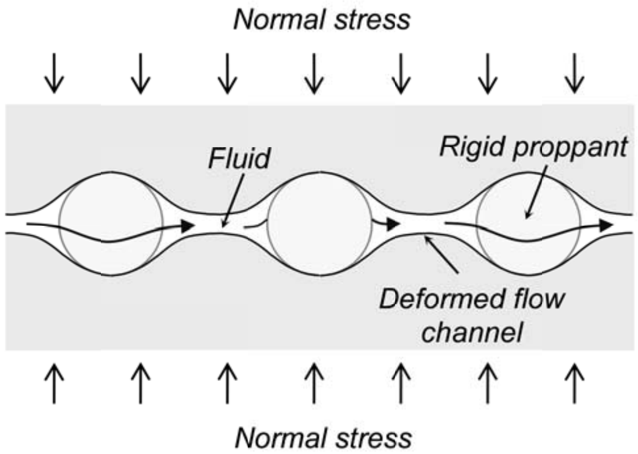

Figure 7. Deformation of the cleat due to rock stresses and the additional tortuosity of the flow path due to the presence of the proppants (Khanna et al, 2012b).

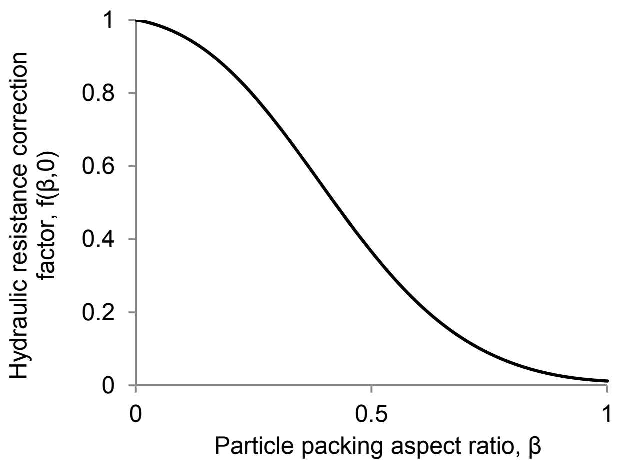

Figure 8. The hydraulic resistance correction factor versus the packing aspect ratio (Khanna et al, 2012b).

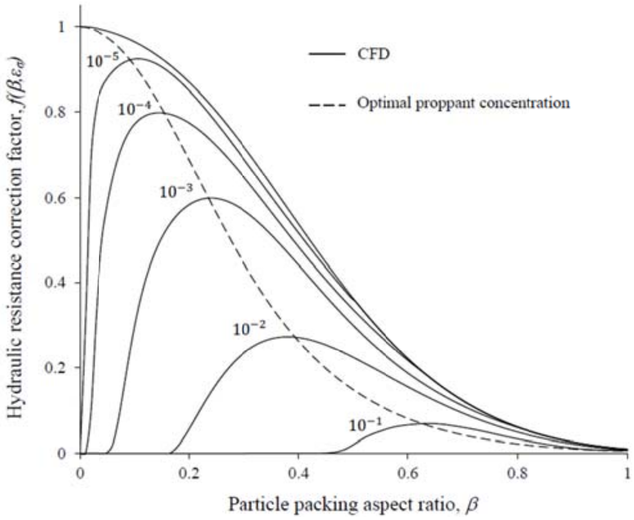

Figure 9. The resistance correction factor ($f(\beta,\sigma/E)$) for different packing aspect ratios ($\beta=2r_s/l$) and dimensionless stresses ($\varepsilon_\sigma=\sigma_n/E$)(Khanna et al, 2012b).

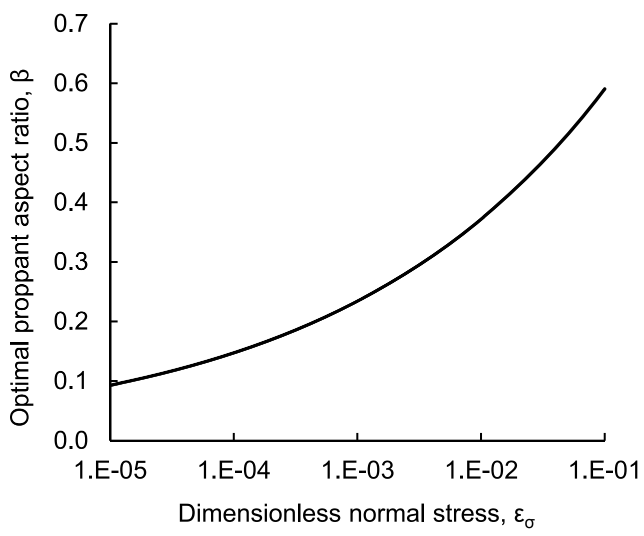

Figure 10. The optimal proppant aspect ratio versus stress (Khanna et al, 2012b).

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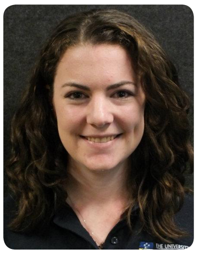

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Chapter 4

Experimental study of graded proppant injection in coal bed methane reservoirs

4.1 Enhancement of CBM well fracturing through stimulation of cleat permeability by ultra-fine particle injection.

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Australian Petroleum Production and Exploration Association (APPEA) Journal 54, 155-166, 2013.

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Author Contributions

By signing the Statement of Authorship, each author certifies that their stated contribution to the publication is accurate and that permission is granted for the publication to be included in the candidate's thesis.

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Contribution to the Paper	Laboratory design and study, planning of the article data interpretation and writing the manuscript		
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Contribution to the Paper	Supervised development of work, help in data interpretation, manuscript review and assessment		
Signature		Date	15/01/2015

Name of Co-Author	Ray Johnson
Contribution to the Paper	Article review and assessment
Signature	Date 12/1/2015

Enhancement of CBM well fracturing through stimulation of cleat permeability by ultra-fine particle injection

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ABSTRACT

Coal permeability declines due to fracture closure during the dewatering stage. A new technique for stimulation of natural coal cleats through ultra-fine and ultra-light high-strength particle injection into a coal fracture system is proposed. Coupling this technique with hydraulic fracturing treatment resulted in particles entering cleats under leak-off conditions.

The following optimal water-based coreflood experimental conditions were determined by applying Derjaguin-Landau-Verwey-Overbeek (DLVO) theory to the interaction between glass particles and the coal matrix: stability of a particle-based suspension (no agglomeration); repulsion between particles and the coal matrix; and, immobilisation of coal natural fines. At these conditions, these particles were placed inside cleats and were not attached to the cleat entrance, leading to less external cake formation; no formation damage due to fines migration was observed. The experimental study was carried out on some bituminous coal samples. Micro-sized glass particles were injected into a coal core at minimum effective stress until core permeability decreased to a value predetermined by a mathematical model. An increase of the effective stress to its maximum value by injection of particle-free water resulted in an approximate three-times increase in coal permeability, when compared to the original value.

The proposed technique can be used for stimulation of a natural fracture network in conventional and unconventional reservoirs, as well as for the enhancement of conductivity of micro-fractures around the hydraulically induced fractures. These particles can be used as a non-damaging leak-off additive during hydraulic fracturing stimulation treatments leading to long-term fracture conductivity.

KEYWORDS

Coal, coal seam gas, stimulation, ultra-fine particle injection, stress, liquid permeability, well fracturing.

INTRODUCTION

Coal seam reservoirs are usually low permeable, therefore increasing permeability has significant influence on enhanced gas recovery of coal bed methane (CBM) by increasing gas flow in cleat system into the well bore. A unique characteristic of naturally fractured rocks (including coal seams) is that their permeability is sensitive to pressure and stress. Pressure decline during production, which results in the deformation of the matrix and fractures, therefore leads to significant reduction in the permeability (Palmer, 2009).

To achieve economical production rates, most coal seam gas (CSG) wells require some form of stimulation. Hydraulic fracturing has been the most cost-effective stimulation method for CSG reservoirs (Johnson et al, 2002). Hydraulic fracturing of coal seams is mainly a process that interconnects the natural fracture network to the wellbore (Holditch et al, 1968). Permeability enhancement of the complex micro fracture network around the hydraulically induced fractures, therefore, significantly increases the efficiency of hydraulic fracturing in CSG reservoirs.

Several studies have been done on improvement of permeability of the natural fracture systems. Hossain et al (2002) and Rahman et al (2002) proposed a shear dilation stimulation model in which permeability of natural fracture systems increases during fluid injection. This model accounts for mismatches and asperities that are created due to displacement of fracture walls out of their original position. Riahi and Damjanac (2013) introduced a two-dimensional model describing an interaction between hydraulic fracture and discrete fracture networks, in which fluid injection rate and effective permeability of the reservoir are the most important factors affecting the reservoir response to interconnectivity between hydraulic fracturing and natural fracture systems. Khanna et al (2013) proposed a method for stimulation of natural fracture system by graded proppant particle injection. During fluid injection, pressure and, consequently, the opening of natural fractures decreases with increasing distance from the wellbore. Injecting fine-sized particles followed by those of larger size could, therefore, lead to sequentially filling the widened natural fractures and the creation of a partial monolayer in these fractures. This would result in expansion of the stimulated zone and increase in the well productivity index. The process could be coupled with a hydraulic fracturing treatment to stimulate natural cleat network around hydraulically induced fractures, allowing the graded proppant to enter cleats or fractures under leak-off conditions. This model, however, has not been confirmed experimentally yet.

Hydraulic fracturing treatment fractures are filled with proppant particles in a method known as frac and pack. Darin and Huitt (1959) showed that during hydraulic fracturing, in cases where an induced fracture is propped by a partial monolayer of large-sized proppant particles, larger permeability would be reached than when fractures are fully packed with small-sized, multilayer proppants. Due to technological constraints, however, placement of partial proppant monolayer has not been possible until recently. To facilitate proppant movement in narrow fractures, ultra-lightweight proppants (ULWPs) have been developed (Brannon et al, 2004). With the use of ULWPs and low viscosity fracturing fluids, partial monolayer placement in hydraulic fracturing has become possible (Chambers and Meise, 2005). The use of waterfracs with low concentration of ULWP has met tremendous success and has proved to be a promising technology (Brannon and Starks II, 2009; Cramer, 2008; Chambers and Meise, 2005; Brannon et al, 2004). Although this method has been successfully tested for hydraulic fracturing, the experimental proof for stimulation of a natural fracture system by placing ULWPs in cleat networks is not available in the literature.

In this paper permeability enhancement of well cleat coal cores has been experimentally evaluated by placing ultra-light, high-strength microparticles into their fracture system. The structure of the paper is as follows. In Section 2 the properties of coal samples and glass particles are presented. Section 3 outlines experimental procedures for particle concentrations and zeta-potential measurements for glass particles and coal. This section describes experimental setup and procedures for coal permeability measurements at various effective stresses. The paper then gives a detailed discussion of the total potential of interaction between particles and the coal matrix, which leads to the proper placement of particles in a cleat network, excluding natural fines migration in coal as presented in Section 4. In conclusion, the authors identify the major outcomes of the present study, and give practical recommendations for the application of the proposed method for stimulation of coal cleat systems.

MATERIALS

Coal

A bituminous coal block originating from Dawson Central Coal Mine (Queensland, Australia) from about 70 m of depth was used as a source material for cutting four cylindrical core plugs with well-developed cleats. Two core plugs were drilled parallel to the bedding plane (B-1, B-2) and used for particle deposition tests (Fig. 1), and the other two samples (B-3, B-4) were drilled normal to the bedding plane and used in uniaxial stress tests for the evaluation of geomechanical properties. After drilling and cutting the core surfaces, lengths and radiuses of the cores were precisely measured with a micrometer.

Before starting particle deposition tests, core samples (B-1, B-2) were tightly wrapped with Teflon to prevent water leakage between the outer surface of a core and the Viton sleeve. Porosity of these samples was measured by three different methods: helium porosimetry, imbibition method and fracture porosimetry with 0.6 M NaCl solution. Results of these measurements are presented in Table 3. Coal samples were evacuated in a desiccator at residual pressure of 2×10^{-2} mbar for 24 hours. The mass of the samples after evacuation was measured by an analytical balance (Model KERN EW 420-3NM, Inscale Ltd.) with an accuracy of ± 0.0005 g. The samples were then saturated by 0.6 M NaCl solution in MilliQ water, by ingress of solution into desiccator. Since the coal samples were saturated with a brine solution, the effect of sorption of methane on the coal sample's permeability was not taken into account.

Particles

B-1 B-2

Figure 1. Photographs of coal cores.

Fracture openings in natural cleat systems are much smaller than fracture widths during hydraulic fracturing; existing commercial proppants, therefore, are not suitable for stimulating natural fracture networks due their large size. Ultra-fine, ultra-light and high-strength hollow borosilicate glass microspheres Sphericel 110P8 and Sphericel 60P18 (Potters Industries LLC) were used for injection into the coal cleat network. Properties of these particles and their size distribution, as supplied by the manufacturer, are shown in Table 1. Particle size distribution given in this table, however, is not sufficiently discriminative in respect to a wider size distribution to give us a more accurate value—weighted mean particle size. A more detailed size distribution of these particles was measured by the Mastersizer 2000 particle size analyser (Malvern Instruments Limited).

EXPERIMENTAL

Particle concentration and zeta-potential measurements

Concentrations of particle-based suspensions were measured by PAMAS S4031 GO (PAMAS GmbH), a portable particle counter. The number of particles across their size distribution range was converted to particle volumetric concentration (ppm). In all tests the concentration of particles in suspensions was 50 ppm.

To calculate total potential of interaction, electrophoretic mobilities of injected particles and the coal matrix were measured by the Zetasizer Nano Z (Model ZEN3600, Malvern Instruments Ltd.). Electrophoretic mobilities were converted to zeta-potentials using Smoluchowski model (Hunter, 1981). Verification of the Zetasizer was carried out by measuring electrophoretic mobility of zeta-potential transfer standard with –42.0 mV ± 4.2 mV (Number: 411201, Malvern Instruments Ltd.). The obtained zeta-potential value of –38.9 mV agrees with that reported by the manufacturer of the standard within the reported uncertainty.

Experimental setup

A hydrostatic core flooding system was used for permeability measurement tests (Fig. 2). This coreholder system is connected to a data acquisition system, which allowed monitoring and control of the inlet, back and differential pressures, and inlet flow rate of suspension. Differential pressure was maintained within approximately 6% of reading, and overburden pressure was controlled within ± 0.3%. A suspension with ultra-fine glass particles was placed inside a stainless steel high-pressure accumulator. A high-performance liquid chromatography (HPLC) pump uses a series of manual valves to deliver either a suspension or various saline solutions through a coal sample. Control of the outlet pressure was carried out by a back-pressure regulator, measured by a gauge pressure transmitter, and allowed to maintain a stable pressure drop across the coal plug.

Experimental procedure

GEOMECHANICAL PARAMETERS

Coal cores B-3 and B-4 were tested in a uniaxial stress test rig, and Young's modulus and Poisson's ratio were calculated from the experimental axial load, axial and radial strain data. The uniaxial stress test necessitates that the core surface is flat and smooth, as mechanical load is distributed uniformly on its surface. This was achieved by applying a dental paste on the core surface, followed by drying and then polishing the paste surface (Fig. 3). Four strain gauges were attached to a core (two in axial and two in radial directions) for strain measurement. After gradually increasing uniaxial loads to the samples, axial and radial strains were measured and recorded by an automatic data acquisition system (Fig. 4).

Table 1. Properties of injected particles.

Particle name	Bulk density, kg/m³	Density, kg/m³	Particle size, μm				Max working pressure, psi
			D10	D50	D90	D97	
110P8	490	1,100	5	10	21	25	10,000
60P18	320	600	9	19	33	36	8,000

Figure 2. Laboratory set-up.

Young's modulus and Poisson's ratio of the samples were calculated as follows:

$$\sigma = \frac{F}{A} \tag{1}$$

Where σ is the axial stress, F is the load and A is the area of interception of the core;

$$E = \frac{\sigma}{\varepsilon_\alpha} \tag{2}$$

where E is Young's modulus and ε_α is axial strain; and,

$$\upsilon = \frac{\varepsilon_\alpha}{\varepsilon_r} \tag{3}$$

where υ is Poisson's ratio, ε_α is axial strain and ε_r is radial strain.

Averaged values of υ and E for coal samples B-3 and B-4 which calculated based on experimental data are presented in Table 2.

PERMEABILITY HYSTERESIS REMOVAL

To compare core permeability data throughout experiments and to observe changes in permeability, a coal sample should reach a condition when it repeatably responds to variations of effective stress (Robertson et al, 2007; Chen et al, 2011; Qiao et al, 2012)—the absence of hysteresis in permeability for increasing and decreasing the effective stress. This was achieved by setting an overburden pressure at 1000 ± 1.5 psi, and an average pore pressure was cycled from 50 psi up to 900 psi and back to 50 psi, while measuring permeability variation due to changes in the net stress.

INITIAL CLEAT POROSITY AND PERMEABILITY

Initial cleat porosity and permeability of each coal core was measured according to Gash (1991) as follows: the coal sample saturated with 0.6 M NaCl solution in MilliQ water was exposed to overburden pressure of 150 psi, and flow of the solution used for saturation was established through the sample with inlet pressure kept constant at 50 psi. The initial permeability was measured, and then the solution was displaced by gaseous Helium, which was collected and its measured mass was converted to the sample's cleat initial porosity.

EFFECTIVE STRESS COEFFICIENT

The concept of effective stress was first presented by Terzagi (1923), and is defined as the difference between total stress and pore pressure ($\sigma^{eff} = \sigma - p$). Biot (1941) proposed a coefficient α other than unity ($\sigma^{eff} = \sigma - \alpha p$) to modify effective stress principles for fluid saturated rocks, to account for the effect of rock compressibility. Effective stress law reduces the number of independent variables from two to one, which significantly simplifies the analysis of pore pressure and the stress dependency of rock properties (e.g., permeability). Walsh (1981) developed a graphical technique to calculate the effective stress coefficient. In this method permeability curves are plotted as functions of pore pressure for constant values of confining pressure, then for constant values of permeability, pore pressure data are cross-plotted as a function of confining pressure. By plotting confining pressure vs pore pressure, the effective stress coefficient (Biot coefficient) can be found as the slop of this curve. After finding the Biot coefficient from these graphs, it is possible to plot permeability as a function of effective stress.

The cross-plotting method was used to determine the Biot effective stress coefficient α. For each sample, therefore, three permeability measurement tests were conducted. In each test, the overburden pressure was set and held at an arbitrary constant value (700, 1,000 and 1,500 psi), and average pore pressure was increased from 50 psi up to 100 psi less than the respective overburden pressure. The procedure details of the cross-plotting method have been explained by Walsh (1981) and Qiao et al, (2012).

COAL PERMEABILITY MEASUREMENTS DURING PARTICLE PLACEMENT

After removing permeability hysteresis from core samples and calculating effective stress coefficients, permeability tests were conducted with and without particle injection. In all tests, the pressure difference across coal samples was kept constant at ≈ 20 psi. Pore pressure was evaluated as the mean value between inlet and backup pressures. Permeability measurements were carried as follows. At the start of each test, overburden pressure was developed and kept constant by manual pressure generator control. Pore pressure increased stepwise, and after its stabilisation, the following experimental parameters were recorded by a real-time data acquisition system: Differential pressure; inlet and backup pressures; and, suspension flowrate. The permeability of the sample was calculated using Darcy's law in real-time.

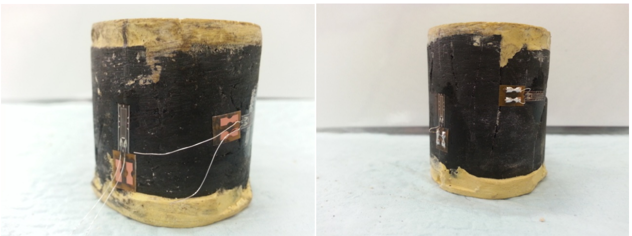
To inject particles deeply through the fracture system, the mean particle size should be lower than the average fracture opening, due to the presence of asperities on the fracture walls and the tortuosities of the flow path in the fracture network. Valko and Economides (1995) proposed a shape factor

$$\gamma = \frac{d_p}{h} \approx \frac{1}{3} \tag{4}$$

for proppant placement in hydraulically-induced fractures where d_p is particle diameter and h is mean fracture opening. For particle placement in natural fracture systems, however, criteria for this shape factor are not available in the present literature. In the present study, calculated values for the shape factor varied from 0.22–0.39, depending on the mean size of used particles and the average initial fracture apertures (Tables 1, 3).

Two competitive mechanisms, shown in Figure 5, affect permeability of the cleat network after particle placement, namely: the reduction in fracture aperture due to gradually increasing effective stress, and additional tortuosity of the flow path created by the presence of deposited proppant particles. Dense packing of the proppant particles minimises the deformation of the fracture, whereas a sparse packing minimises the additional tortuosity to the flow path. To minimise the net negative effect of the above mechanisms, an appropriate proppant concentration should be determined, at which fracture conductivity reaches its maximum value. Several parameters affect this optimal proppant concentration: Maximum effective stress; rock properties (i.e., Young's modulus, Poisson's ratio and rock compressibility); and, the mechanical strength of the proppant.

Khanna et al (2012) developed a semi-analytical mathematical model to calculate the optimal proppant concentration in narrow fractures. It was proposed a correction factor, $f(\beta, \varepsilon_\sigma)$, such that the fracture permeability after proppant placement is



B-3 B-4

Figure 3. Sample preparation for uniaxial stress tests.

Figure 4. Uniaxial stress test rig.

Table 2. Geomechanical properties of bituminous core plugs (B-3, B-4).

Coal	D, cm	L, cm	υ	E, Gp
B3	3.91	3.87	0.29	1.025
B4	3.89	4.12	0.27	0.910

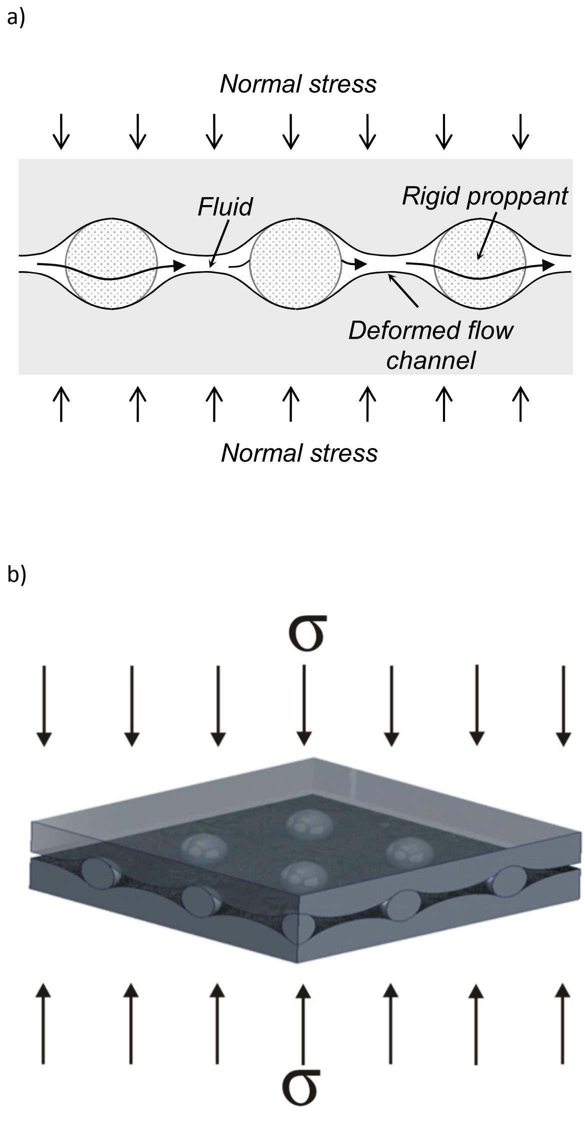


Figure 5. Deformation of the cleat due to rock stresses, and the additional tortuosity of the flow path due to the presence of the proppants. a) Two dimensional view; b) three dimensional view.

$$k_{fr}^{prop} = f(\beta, \varepsilon_\sigma) \times k_{fr} \tag{5}$$

This correction factor is a function of two dimensionless parameters: The dimensionless optimum particle packing aspect ratio,

$$\beta = \frac{d_p}{L} \tag{6}$$

where d_p is particle diameter and L is particle distance; and, dimensionless stress,

$$\varepsilon_\sigma = \frac{\sigma(1 - \upsilon^2)}{E} \tag{7}$$

where σ is normal stress to fracture walls, υ is Poisson's ratio and E is Young's modulus (Fig. 6).

The particle packing aspect is the areal particle concentration in the fracture system. When the aspect is equal to zero, then it has zero particle concentration, and when it is equal to one, it implies that the fracture system is fully packed by particles. For each rock characterised by its unique value ε_σ, therefore, it is possible to calculate an optimal particle concentration at which the correction factor, $f(\beta, \varepsilon_\sigma)$, is at its maximum value. Khanna et al (2013) used this method for modelling graded proppant injection in naturally fractured systems. If proppant particles are placed in fractures in maximum pore pressure (minimum effective stress) under optimum particle packing aspect ratio, permeability correction factor is $\approx f(\beta, 0)$. This means that after increasing the effective stress (decreasing pore pressure) up to ε_σ, permeability correction factor becomes $f(\beta, \varepsilon_\sigma)$. In the present study, the value of dimensionless stress $\varepsilon_\sigma \approx 0.0063$ was calculated using averaged experimental data for υ and E for coal samples B-3 and B-4 (Table 2), and maximum experimental effective stress data. This was followed by graphical evaluation of the maximum values for $f(\beta, 0) \approx 0.65$ and $f(\beta, \varepsilon_\sigma) \approx 0.37$ from Figure 6. According to the above model, multiplying $f(\beta, 0)$ value by k_{fr} results in minimum value of coal permeability until the particles were allowed to be placed in fractures. As the first estimation, therefore, particle placement should proceed until permeability is decreased until ≈ 65%.

RESULTS AND DISCUSSION

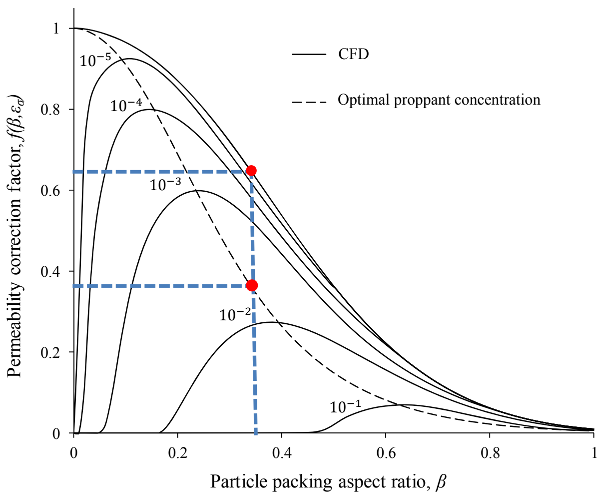


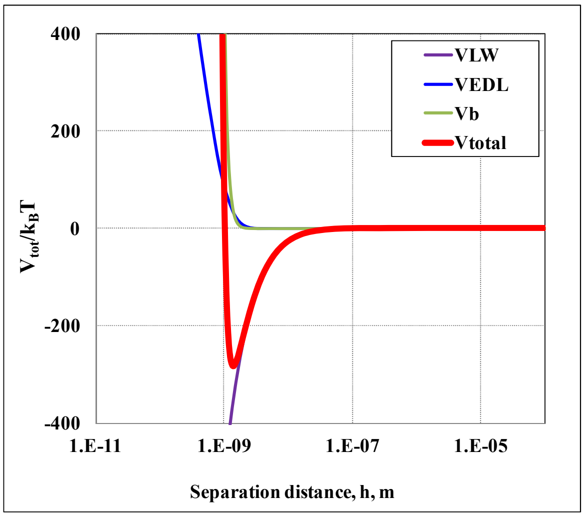
Figure 6. Correction factor vs particle packing aspect ratio for various values of the dimensionless confining stress. Values indicated above individual curves (Khanna et al, 2012).

Particle-particle and particle-coal matrix interactions

When depositing particles inside a coal cleat system, its important that particles don't agglomerate and attach to the coal matrix. Both of these processes lead to formation of an external cake on the inlet surface of the coal core sample, and prevent particles penetrating deep into the coal matrix. The DLVO theory can be used to evaluate the extent of particle-particle and particle-coal interaction at various experimental conditions, such as the salinity and pH of particle suspension.

According to DLVO theory, several interaction potentials contribute to the total potential of interaction between particle-particle and particle-wall (surface), V_{tot}, caused by attractive long-range London-van der Waals forces, V_{LW}, short-range attractive/repulsive electrical double layer, V_{EDL}, and Born repulsion, V_B, according to the following formula:

$$V_{tot} = V_{LW} + V_{EDL} + V_B \tag{9}$$



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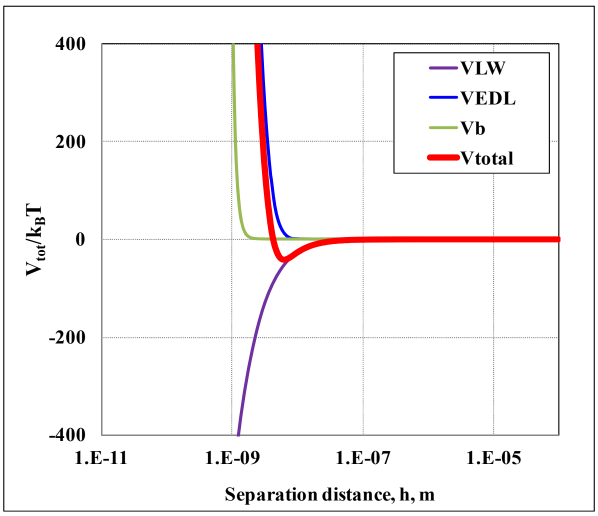

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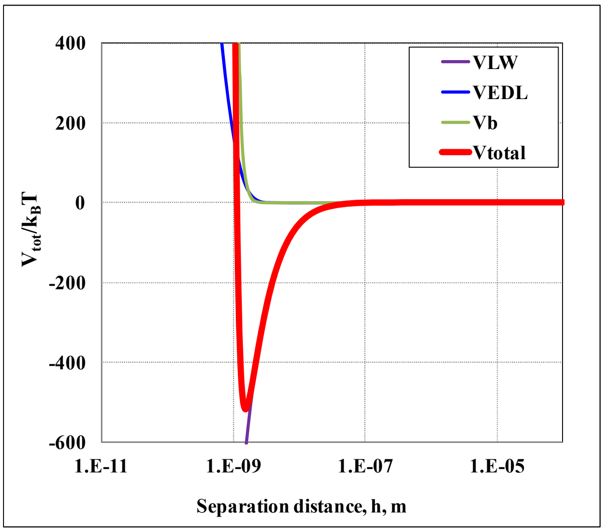
Figure 7. Effect of salinity on particle-particle DLVO interaction for small particles. a) Interaction potential for particle-particle ($S = 0.6$ M NaCl, $d_p = 10$ μm), b) interaction potential for particle-particle ($S = 0.1$ M NaCl, $d_p = 10$ μm)



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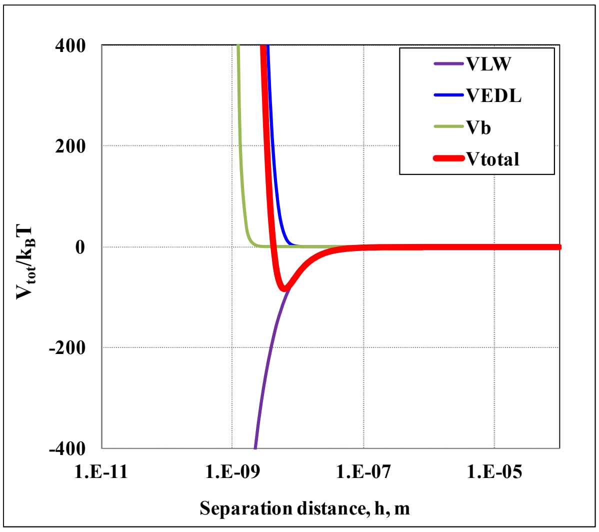
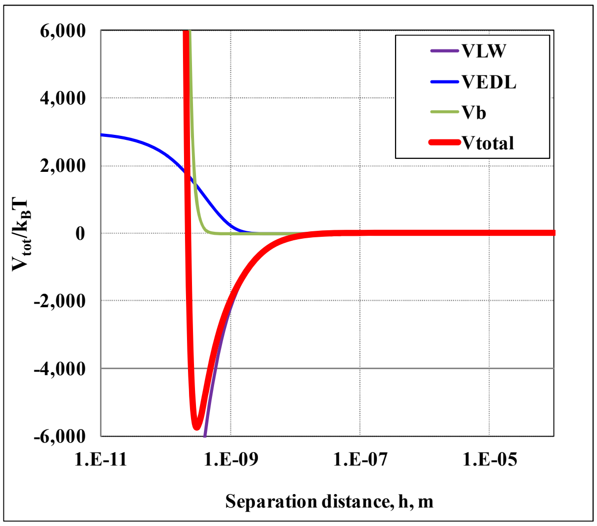


b)

Figure 8. Effect of salinity on particle-particle DLVO interaction for large particles. a) Interaction potential for particle-particle ($S = 0.6$ M NaCl, $d_p = 19$ μm), b) interaction potential for particle-particle ($S = 0.1$ M NaCl, $d_p = 19$ μm).

Formulas proposed by Gregory (1975) for sphere-plate and sphere-sphere were used for calculation of retarded V_{LW} between injected particles and the coal matrix. Since the thickness of the double layer is significantly smaller than the particle size, then V_{EDL} for sphere-plate and sphere-sphere is calculated according to Gregory (1981). Sphere-plate V was evaluated according to Ruckenstein and Prieve (1976). The total potential of interaction between particle-particle and particle-coal at various experimental conditions were calculated and shown in Figures 7–10.

As shown by Figures 7–8, decrease in the salinity of the suspension from 0.6–0.1 M NaCl makes interaction between particles more repulsive, since the depth of the primary minimum decreases by ≈ 5.5–6.5 times for both sized particles. Larger particles experience greater attraction, and, therefore, have greater tendency for agglomeration than smaller ones at both suspension salinities. For this reason, the salinity of the suspension during large particle injection should be lower than that when depositing smaller particles. The presence of shallow secondary minima on DLVO potential curves for both sized particles may not lead to agglomeration due to low particle concentration.



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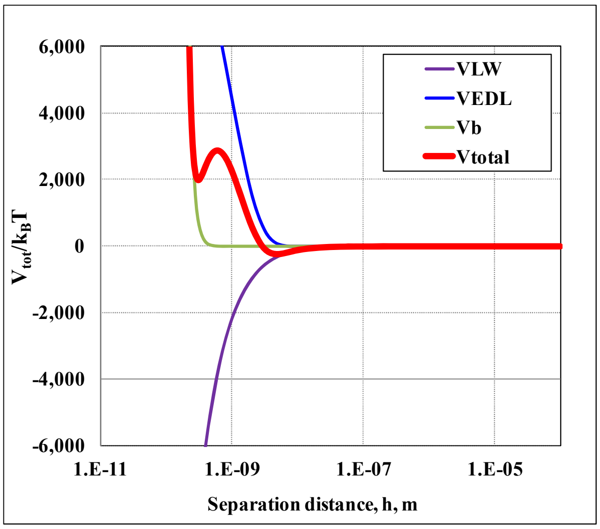


b)

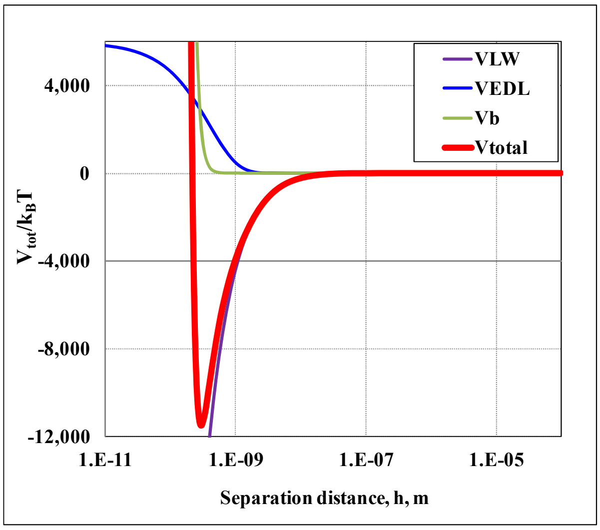
Figure 9. Effect of salinity on particle-coal DLVO interaction for small particles. a) Interaction potential for particle-coal ($S = 0.6$ M NaCl, $d_p = 10$ μm), b) interaction potential for particle-coal ($S = 0.1$ M NaCl, $d_p = 10$ μm).

Variation of salinity has a more profound effect on particle-coal interaction than on particle-particle interaction due to the different nature of materials (Figs 9–10). Reduction in the salinity for both particle sizes significantly changes the interaction between particles and the coal matrix; very high positive energy barriers of ≈ 2,800 and 5,750 k_BT prevent particles from attachment to the coal matrix surface.

In the present study, fixing the salinity of the suspension at 0.1 M NaCl makes experimental conditions favourable for both sized particle deposition into coal cleats without particle agglomeration and attachment to the coal surface—excluding the formation of external cake.

Permeability hysteresis removal and coal properties evaluation

Permeability hysteresis was observed for the entire net stress range of 950 psi during the first pore pressure cycle, reaching ≈ 24.2% at a net stress of 450 psi for the sample B-2.



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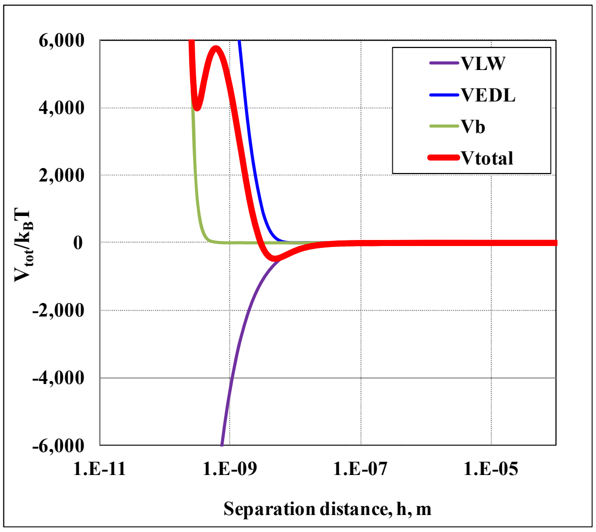

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Figure 10. Effect of salinity on particle-coal DLVO interaction for large particles. a) Interaction potential for particle-coal ($S = 0.6$ M NaCl, $d_p = 19\ \mu m$), b) interaction potential for particle-coal ($S = 0.1$ M NaCl, $d_p = 19\ \mu m$).

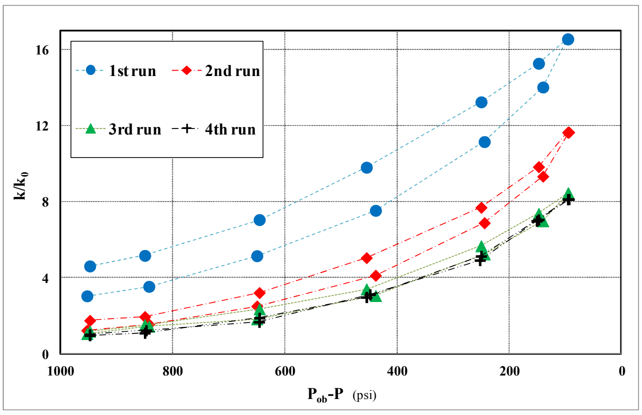


Figure 11. Permeability Hysteresis during load-disload cycles (Sample B-2, Salinity = 0.6 M NaCl).

Additional pore pressure cycles reduced the hysteresis until repeatable permeability-vs-net stress curves were obtained (Fig. 11). With each load/unload cycle, the degree of hysteresis gradually declined, and after the fourth cycle it reached the value less than experimental uncertainty for permeability, which is equal to 3.1% (Badalyan and Carageorgos et al, 2012). This allowed the authors to reach an elastic response of the coal sample. Similar load-unload curves were obtained for the sample B-1. After hysteresis removal, both coal samples are ready for particle deposition experiments.

Two coal samples showed consistent results for cleat porosity and permeability: Permeability of sample increased with its porosity (Table 3). The initial fracture opening h_0 and the fractures spacing α can be related to the initial permeability and porosity of the fracture system by assuming a regular fracture arrangement. For a matchstick arrangement of matrix blocks, the formulae for permeability and porosity are as following (Seidle, 2011):

$$\text{Ø}_0 = \frac{h_0}{500\alpha} \tag{8}$$

$$k_0 = 1.0555 \times 10^5\ (\text{Ø}_0^3\alpha^2) \tag{9}$$

Where α is cleat spacing, mm; h_0 is initial cleat opening, μm; k_0 is initial cleat permeability, mD; Ø_0 is cleat porosity. Data for measured initial permeability and porosity, and calculated values for initial cleat opening and cleat spacing, are reported in Table 3. Values of effective stress coefficients for two coal samples were evaluated as a mean value of the slopes of three $P_{ob} = f(P_{pore})$-plots, (see section on effective stress coefficient) and are given in Table 3 agreeing with each other. Later, these coefficients were used for the calculation of effective stress, and, therefore, coal permeabilities were plotted as functions of effective stress. In all consecutive experiments with particle placement the inside coal cleat network, experimental data were plotted as $k = f(\sigma^{eff})$ shown in Figures 12 and13.

Particle placement

Experimental conditions not favourable for successful particle placement and characterised by high suspension salinity were created in order to study possible implications during particle placement. As follows from Figure 12, the decreasing of effective stress (increasing pore pressure) continued until ≈ 250 psi. At this point, corresponding to the minimum effective stress, 0.6 M NaCl suspension with smaller particles (d_p = 10 μm) was injected. Consecutive coal permeability decrease was monitored and recorded in real-time. When permeability decreased by ≈ 35% of its initial value, injecting suspension was stopped. After that, a background 0.6 M NaCl solution was injected at gradually increased effective stress. Coal permeability measured at each value of effective stress showed that no increase in permeability was observed at maximum effective stress after particle placement. This is due to particle agglomeration, their attachment to the coal matrix and consecutive external cake formation at the entrance of coal cleats. Some particles penetrated into the coal cleat system leading to a permeability increase, whereas those which formed a cake are responsible for the reduction in coal permeability. Net effect of these two processes is shown in Figure 12, as invariability of permeability at maximum effective stress.

Results for total potential of interaction for particle-particle and particle-coal matrix led us to conditions at which mutual relative repulsion between particles and particles-coal was favorable for successful particle placement.

Table 3. Properties of bituminous core plugs (B-1, B-2).

Coal	D, cm	L, cm	Φ_W, %	Φ_H %	Φ_f*,%	α	k_0*, mD	h_0*, µm	a_0*, mm
B1	3.88	2.45	3.1	5.26	0.61	0.82	5.4	45.79	15.01
B2	3.88	2.96	3.53	6.27	0.64	0.9	6.22	48.1	14.52
*: ($P_{ob} - P_{inlet}$ = 100 psi)									

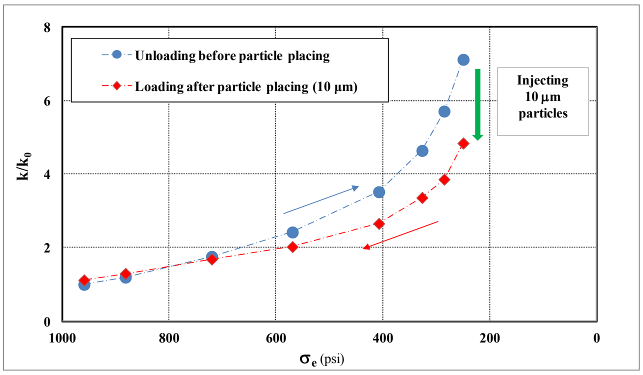
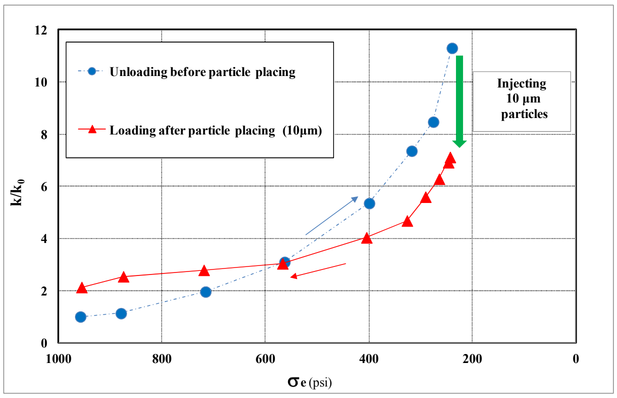


Figure 12. Normalised permeability vs effective stress (Sample B-1, Salinity = 0.6 M NaCl) before and after proppant injection in high-salinity suspension.

In the next test, sample B-2 was saturated by 0.1 M NaCl solution, and its permeability was measured at decreasing effective stress. At a minimum value of effective stress, injection of 0.1 M NaCl suspension with smaller particles (d_p = 10 μm) started. This injection resulted in a decrease of coal permeability, which was continuously monitored and recorded. After permeability reached ≈ 35% of its initial value, injection of suspension stopped. The HPLC pump started injection of the background 0.1 M NaCl solution through the coal sample at gradually increased effective stress. When the system reached maximum effective stress, permeability of the coal sample was two-times higher than that at the similar value of maximum effective stress before particle deposition. As follows from Figure 13-a, the application of lower salinity of suspension made it possible to increase permeability of the cleat system at maximum effective stress. This is supported by the DLVO curves showing mutual particle-particle and particle-coal repulsion.

By placing large-sized particles after the deposition of smaller ones, the effectiveness of the so-called graded proppant injection principle may be proved. For this purpose, after the smaller particle deposition the system was again returned to the minimum effective stress, corresponding to maximum cleat opening and 35% of the initial non-deposited sample permeability. This case, however, dealt with a changed system—the coal cleat network is filled by deposited small particles. In the next step, suspension with bigger particles (d_p = 19 μm) having the same salinity was injected until coal permeability dropped to 50% of initial non-deposited permeability. After that, a background solution with the same salinity was pumped through the coal sample. As follows from Figure 13-b, the final coal permeability at maximum effective stress was again ≈ three-times higher than before particle placement, and ≈ 1.5-times higher than permeability after smaller particle placement. This observation clearly shows that consecutive placement of larger particles after smaller ones keeps bigger fractures opened, proving the positive effect of graded particle injection in coal permeability.



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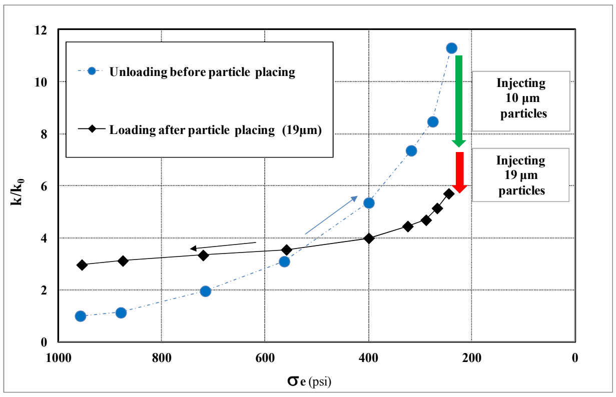

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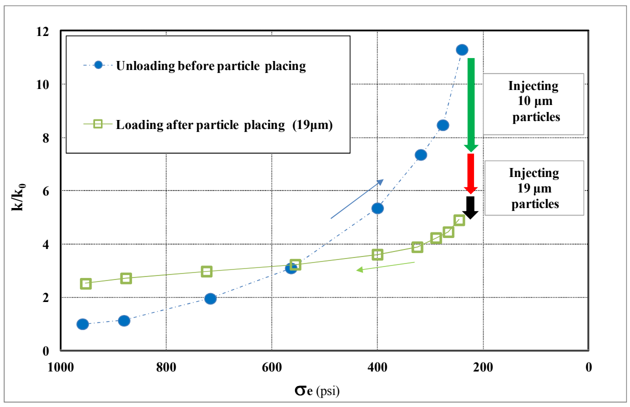

c)

Figure13. Normalised permeability vs effective stress during particle placement (sample B-2, salinity = 0.1 M NaCl). a) Small Particle placement, b) bigger particle placement after small particle injection, c) continuing bigger particle placement.

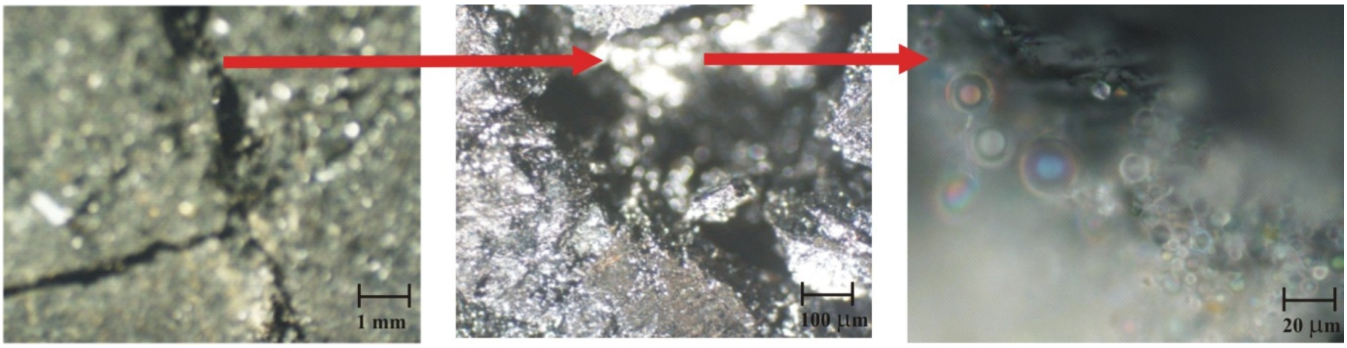

Figure 14. Images of the coal core inlet after low salinity suspension injection. a) Fractured rock scaled, b) single fracture scaled, c) deep inside a fracture.

In the third step, the particle deposition procedure was continued, and suspension with bigger particles ($d_p = 19\ \mu$m) with the same salinity was again injected until coal permeability dropped to ≈ 43% of initial non-deposited permeability. As follows from Figure 13-c, it was observed during third particle deposition that the final coal permeability at maximum effective stress decreased by 15% compared to second stage. It means that there exists a critical deposited particle concentration that should not be exceeded due to increased hydraulic resistance because of excessive fracture blockage. Based on the results of these three tests, therefore, the maximum residual permeability at maximum effective stress was achieved after reducing permeability by 50% due to particle placement in minimum effective stress.

After completion of this test, the coal sample was removed from the core holder for examination of its inlet surface using an optical microscope. As follows from Figure 14-a, no external cake is formed at the entrance of the coal cleats. After increasing microscope magnification, layers of deposited particles become visible in cleats (Fig. 14-b,c). These particles cause fractures to remain open at high effective stress.

CONCLUSIONS

Laboratory tests on proppant injection into fractured coal cores and their mathematical model treatment leads to the following conclusions:

- Injection of low salinity suspension of ultra-fine, ultra-light and high-strength glass particles into fractured coal cores at the lowest effective stress enhances the coal permeability three times by keeping fractures open at maximum effective stress.
- Coal permeability reduction at high salinity of particle suspension, leading to particle-rock attraction, is caused by external cake formation through the agglomeration of particles and their attachment to the core external surface.
- According to DLVO theory, for each injected particle size there exists a range of suspension salinities corresponded to high potential energy barriers with mutual particle-particle and particle-coal repulsion. Controlling these experimental conditions prevents particles from agglomeration and attachment to coal matrix, leading to particle deposition inside fractures and permeability enhancement.
- Injection of smaller particles followed by larger ones leads to a greater enhancement of coal core permeability compared with a single-sized particle placement.
- The proposed method of permeability enhancement stimulates the existing coal fracture systems with the maximum injection pressure being lower than the reservoir breakdown pressure.
- The proposed application of using glass particles as non-damaging leak-off additives enhances conductivity of microfractures around hydraulically induced fractures and consequently improves the efficiency of hydraulic fracturing treatments.

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4.2 Stimulation of coal seam permeability by micro-sized graded proppant placement using selective fluid properties.

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Chapter 5

Laboratory based-mathematical modelling for stimulation of coal bed methane reservoirs through graded proppant injection

5.1 Laboratory-based mathematical modelling of graded proppant injection in CBM reservoirs.

Keshavarz, A., Yang, Y., Badalyan, A., Johnson, R., Bedrikovetsky, P.

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5.2 Improving efficiency of hydraulic fracturing treatment in CBM reservoirs by stimulating the surrounding natural fracture system.

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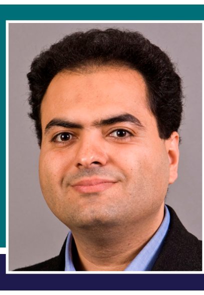
Improving the efficiency of hydraulic fracturing treatment in CBM reservoirs by stimulating the surrounding natural fracture system



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ABSTRACT

A method is proposed for enhancing the conductivity of micro-fractures and cleats around the hydraulically induced fractures in coal bed methane reservoirs. In this technique, placing ultra-fine proppant particles in natural fractures and cleats around hydraulically induced fractures at leak-off conditions keeps the coal cleats open during water-gas production, and this consequently increases the efficiency of hydraulic fracturing treatment.

Experimental and mathematical studies for the stimulation of a natural cleat system around the main hydraulic fracture are conducted. In the experimental part, core flooding tests are performed to inject a flow of suspended particles inside the natural fractures of a coal sample. By placing different particle sizes and evaluating the concentration of placed particles, an experimental coefficient is found for optimum proppant placement in which the maximum permeability is achieved after proppant placement.

In the mathematical modelling study, a laboratory-based mathematical model for graded proppant placement in naturally fractured rocks around a hydraulically induced fracture is proposed. Derivations of the model include an exponential form of the pressure-permeability dependence and accounts for permeability variation in the non-stimulated zone. The explicit formulae are derived for the well productivity index by including the experimentally found coefficient.

Particle placement tests resulted in an almost three-times increase in coal permeability. The laboratory-based mathematical modelling, as performed for the field conditions, shows that the proposed method yields around a six-times increase in the productivity index.

KEYWORDS

Coal, coal seam gas, stimulation, proppant placement, natural fracture system, hydraulic fracturing.

1. INTRODUCTION

Coal bed methane (CBM) reservoirs usually have low permeability. This low permeability yields a low productivity index. To achieve economical production rates, most coal seam gas wells require some form of stimulation (Palmer, 2010). Hydraulic fracturing is the most popular stimulation method in CBM reservoirs (Johnson Jr. et al, 2002). The mechanism and design of hydraulic fractures in CBM reservoirs differs from the fracturing of conventional reservoirs. Hydraulic fracturing of coal seams is mainly a process that interconnects the natural fracture network to the wellbore (Holditch et al, 1988; Xu et al, 2013a, 2013b). Based on highly instrumented experiments in coals, varying dimensions of the created hydraulic fracture are unlikely to be accepting of the main body of proppant introduced into the latter stages of the treatment to maintain hydraulic fracture conductivity (Johnson Jr. et al, 2010a, 2010b; Scott et al, 2010). Any process that can maintain post-frac conductivity throughout the initial complex and pressure-dependent created fractures, natural fractures and cleat networks surrounding the main hydraulic fracture could significantly increase the efficiency of hydraulic fracturing in CBM reservoirs.

The method of natural cleat system stimulation by graded proppant injection has been proposed recently (Bedrikovetsky et al, 2012; Keshavarz et al, 2014; Khanna et al, 2013). The purpose of the graded proppant injection into a natural cleat is to keep it open during the production, where the pore pressure declines with time. Pressure decreases along each tortuous flow path from the well inside the reservoir, so the fracture aperture also decreases with radius. Injecting proppant particles of very-fine mesh size at first, followed by larger particles, may sequentially fill the widened natural fractures and create a partial monolayer proppant placement in the fractures. The placed particles keep the fractures open during water and gas production. The achieved permeability is higher than the initial value. The graded proppant placement expands the stimulation zone and consequently increases the productivity index.

The graded proppant injection could be coupled with hydraulic fracturing treatment to stimulate the natural cleat network and micro-fractures around hydraulically induced fractures, allowing the graded proppants to enter cleats under leak-off conditions and, consequently, increase the efficiency of hydraulic fracturing in CBM reservoirs (Fig. 1).

In the present work, experimental and mathematical studies for the stimulation of the natural cleat system around a hydraulically induced fracture are conducted. In the experimental part, core flooding tests are performed to inject a flow of suspended particles inside the natural fractures of coal cores. By placing different particle sizes and evaluating the concentration of placed particles, an experimental coefficient is found for optimum proppant placement, in which the maximum permeability is achieved after proppant placement. In the mathematical modelling study, a laboratory-based mathematical model for graded proppant placement in naturally fractured rocks around a hydraulically induced fracture is proposed. Derivations of the model include the exponential form of the pressure-permeability dependence and accounts for permeability variation in the non-stimulated zone. The explicit formulae are derived for the well productivity index by including the experimentally found coefficient.

The structure of the text is as follows; the laboratory materials, experimental set up and experimental results are presented in section 2. Section 3 describes the laboratory-based mathematical model for the stimulation of the natural fracture system surrounding the main hydraulic fracture, including the graded proppant injection model, and productivity enhancement and parameter study. The discussion of experimental results and model validity (sections 4 and 5) conclude the paper.

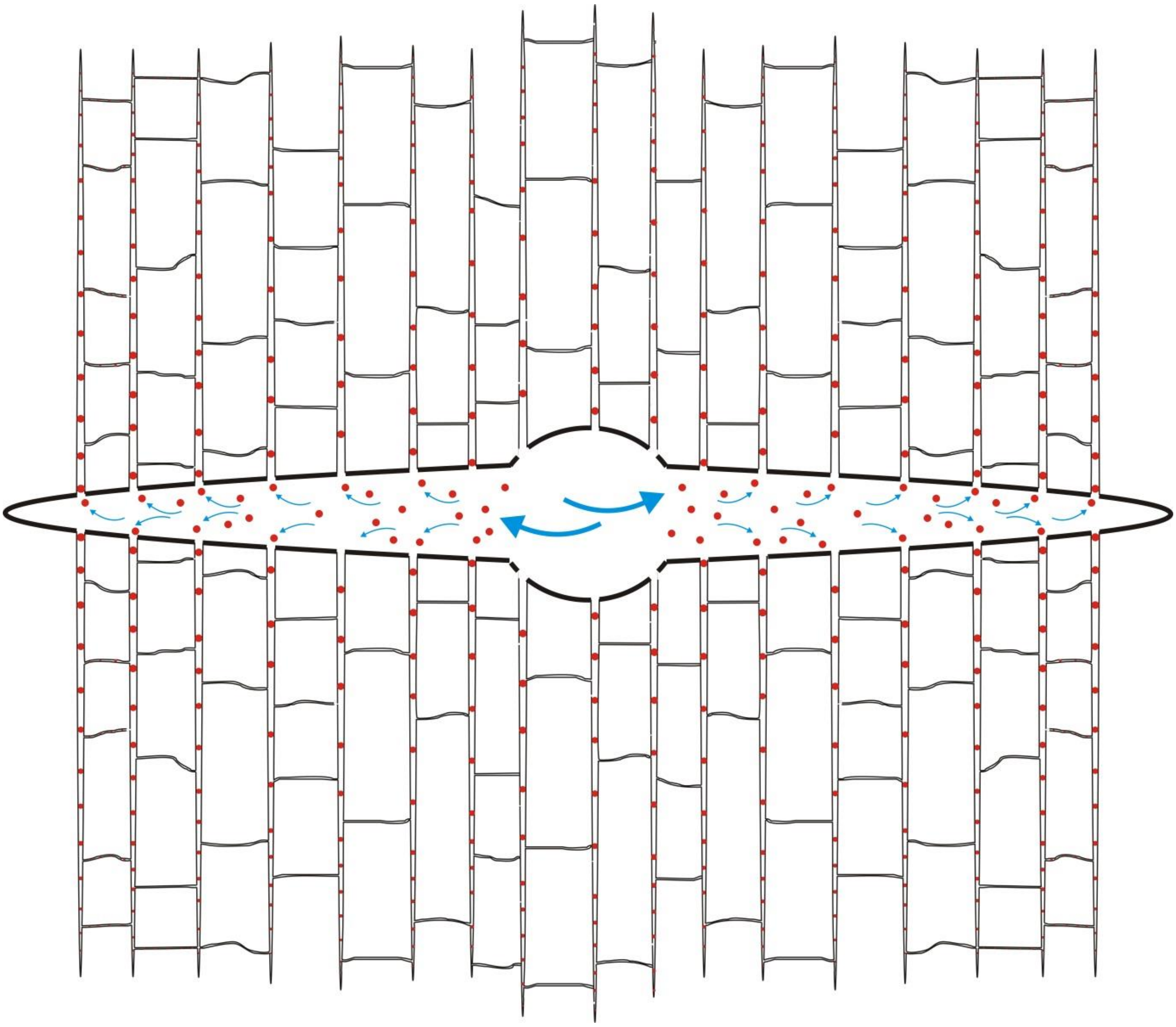


Figure 1. Schematic of graded proppant placement in a natural fracture system surrounding the main hydraulically induced fracture.

2. EXPERIMENT

This section presents the experimental materials and methods, laboratory procedures and the experimental results. Section 2.1 presents the core sample, proppant materials and experimental set up. The effective stress coefficient is calculated for the core sample in section 2.2. Details of proppant placement tests are presented in section 2.3. Section 2.4 describes the method that has been developed for calculating the optimum concentration of placed particle based on experimental results.

2.1 Materials and experimental set-up

A bituminous coal block was taken from the Affinity coal mine (West Virginia, US). Three core samples were drilled from the coal block, and are referred to in the text as C_1, C_2 and C_3. After drilling and cutting of the core surfaces, the core dimensions were measured by a digital caliper and are presented in Table 1. The bituminous coal block and core sample C_1 are shown in Figure 2.

Core sample C_1 is used for the particle placement tests. C_2 and C_3 are used in uniaxial stress tests for the evaluation of geomechanical properties. The Young's modulus and Poisson's ratio values are calculated from the experimental axial load, axial strain and radial strain data (Table 1). The average values of Young's modulus and Poisson's ratio as obtained for samples C_2 and C_3 are assumed for sample C_1; they are denoted in Table 1 as average values.

The proppant particles chosen for injection were the micro-sized hollow borosilicate glass microspheres SPHERICEL 110P8 and SPHERICEL 60P18 (Potters Industries LLC, South Yorkshire, UK). Particle sizes $r_p = 5$ μm and $r_p = 9.5$ μm were used in the tests.

All flooding tests, before and after proppant injection, were conducted by a custom-built coreflooding apparatus (Fig. 3). This coreholder system is connected to a data acquisition system, which allows monitoring and control of the inlet, back and differential pressures, and inlet flow rate of suspension. A suspension with ultra-fine glass particles was placed inside a stainless steel high-pressure accumulator.

Prior to the start of the particle placement tests, the core samples were tightly wrapped with a Teflon tape to prevent water leakage between the core outer surface and rubber sleeve, holding the cores inside a high-pressure core holder. All tests were conducted at constant ambient temperature of 25°C. Core sample C_1 was installed in the core holder and consolidated with a few load cycles before the experiments were conducted to ensure the results are repeatable. Initial cleat porosity and permeability of C_1 were measured according to Gash's method (Gash, 1991) and the values are 0.54% and 5.8 mD, respectively. The fracture aperture (h) and the fracture spacing (a) can be related to the permeability and porosity of the fracture system by assuming a regular fracture arrangement. For a matchstick arrangement of matrix blocks, the formulae for porosity and permeability are given by Equations 1 and 2, respectively (Reiss, 1980; Seidle 2011).

$$\varnothing_f = \frac{2h}{a} \quad (1)$$

$$k = \frac{1}{96} \varnothing_f^3 a^2 \quad (2)$$

The initial fracture aperture (h) and fracture spacing (a) values for C_1, as calculated by Equations 1 and 2, are 50.44 mm and 18.68 mm, respectively.

2.2 Effective stress coefficient

The concept of effective stress, which was first presented by Terzagi (1923), is defined as the difference between total stress and pore pressure ($\sigma^{eff} = \sigma - p$). In Terzagi's effective stress law, it is assumed that the total stress and the pore pressure have similar, but inverse, effects on the variation of the rock properties. To generalise the effective stress law, Biot (1941) proposed a coefficient (α) other than unity ($\sigma^{eff} = \sigma - \alpha p$) to modify the effective stress principle for fluid-saturated rocks, where the effect of total stress and pore pressure are not the same. The effective stress law reduces the number of independent variables from two to one; hence, it significantly simplifies analysis of pore pressure and the stress dependency of rock properties (i.e. permeability).

In this study a graphical technique called the cross-plotting method (Walsh, 1981) was used to determine the effective stress coefficient (α). In this method, for a given core sample, permeability curves were plotted as functions of pore pressure for the constant value of confining stress. Then, for the constant value of permeability, pore pressure data were cross-plotted as a function of confining stress. By plotting confining stress versus pore pressure, the effective stress coefficient could be found as the slope of this curve. Three permeability measurement tests, therefore, were conducted on core sample C_1. In each test, the confining stress was set at a constant value (700, 1,000 and 1,500 psi), and average pore pressure was increased from 50 psi up to 100 psi less than the respective confining stress (Fig. 4a). At permeability values 1, 1.5, 2, 2.5 and 3 mD, confining stress and pore pressure data were plotted in Figure 4b. Biot's coefficient ($\alpha = 0.91$) was determined as the average value of the slope of the curves in Figure 4b.

2.3 Proppant placement tests

Base on filtration theory in porous media, the particle jamming ratio $j = (2r_p/h)$ should not exceed 1/3rd of the average pore size to provide the particle penetration into the rock without being trapped at the inlet face (Bedrikovetsky, 2008). The particle jamming ratio should exceed 1/7th of the average pore size to avoid the capture-free particle motion in the rock; in this case, some particles remain in the cleats and do not allow cleat closure during the pore pressure depletion. To the best of the authors' knowledge, the above thresholds for fractured media are not available in the literature (Zhang et al, 2012; Rodrigues and Dickson, 2014).

For two particle sizes, $r_p = 5$ µm and $r_p = 9.5$ µm, the jamming ratios j_1 and j_2 at the minimum effective stress were calculated for core sample C_1 as 0.21 and 0.39, respectively. Both jamming ratios exceed 1/7th of the average cleat aperture. j_2, however, slightly exceeded 1/3rd of the average cleat opening.

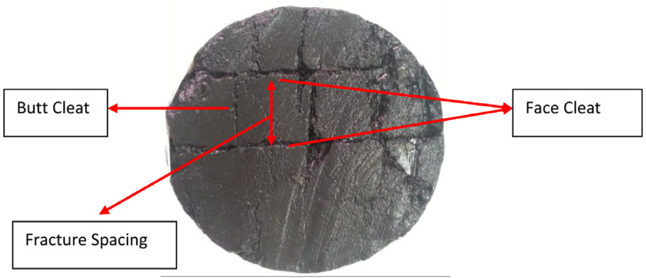
To reduce the risk of proppant particle agglomeration and particle-coal attachment, and consequently external cake formation, low-salinity water with 0.05 M ionic strength was used as the injecting fluid with and without proppant particles. In all tests, the pressure difference across the coal samples was kept constant. Pore pressure was evaluated as the mean value between the inlet and backup pressures.

The injection of particle-free water was carried out under piecewise constant pore pressure in the increasing mode until the maximum pore pressure was reached. The proppant particles were injected at a higher pore pressure to provide the maximum cleat opening. Then the injection of particle-free water was continuous under piecewise constant pore pressure in the decreasing mode until the initial pore pressure was reached.

Table 1. Dimensions and geomechanical properties of the core plugs. *D* is core diameter (cm), *l* is core length (cm), *v* is Poisson's ratio, and *E* is Young's modulus (gigapascal).

Coal	*D* (cm)	*l* (cm)	*v*	*E* (GPa)
C_1	3.86	3.17	-	-
C_2	3.86	4.73	0.3	1.13
C_3	3.87	4.30	0.31	1.25
Ave. (C)			0.305	1.19

a)



b)

Figure 2. a) The bituminous coal block from the Affinity coal mine (West Virginia, US). b) The inlet face of core sample C_1.

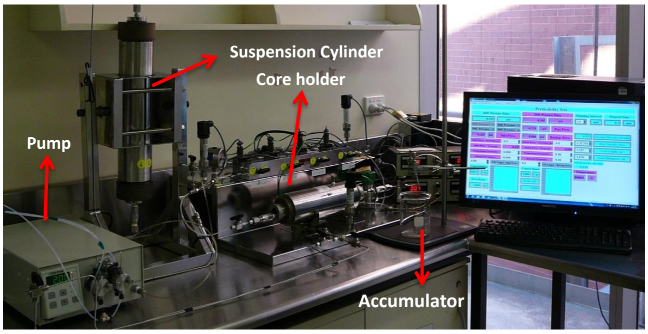
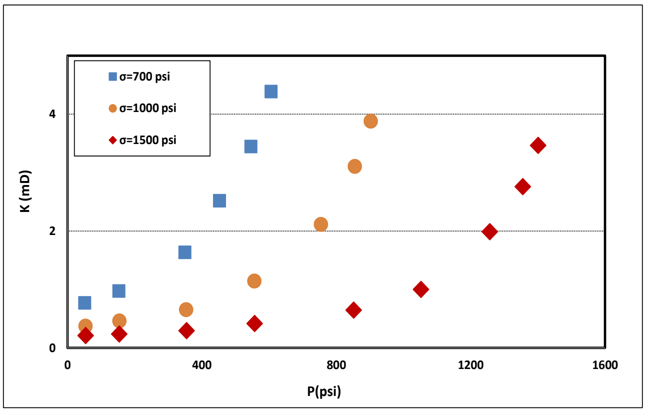


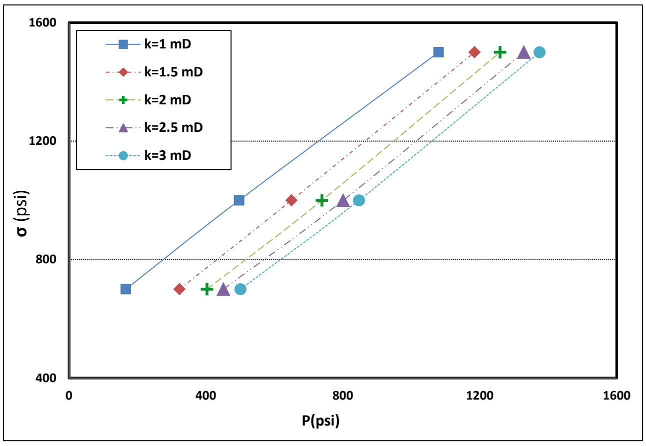
Figure 3. Experimental set up.

The sequence of floods corresponds to the proppant particle injection into the cleat system around the hydraulically induced fracture in the leak-off stage under the elevated pressures. It is followed by water production during the reservoir dewatering.

First, the core is submitted to flood with piecewise constant increasing pore pressure (blue dashed curve from point 1 to point 2 in Fig. 5). Then, 5 μm proppant particles are injected at the maximum pressure, resulting in permeability decline (green vertical arrow from point 2 to point 3). The proppant-free water injection under piecewise constant decreasing pore pressure follows (red continuous curve down from point 3 to point 4). Then, an increase of pore pressure in the same interval follows (the red curve up from point 4 to point 3). Afterwards, 9.5 μm proppant particles are injected at the maximum pressure; the resulting permeability decrease is shown by another green vertical arrow (point 3 to point 5). Waterflood under the pressure decrease is shown by the black continuous curve (point 5 to point 6). The corresponding state point moves up along the black curve (point 6 to point 5). Further proppant injection at high pressure yields further permeability decrease (green vertical arrow from point 5 to point 7). Pressure decrease flood follows the continuous green curve (point 7 to point 8).



a)



b)

Figure 4. a) Permeability versus pressure in different confining stresses. b) Confining stress versus pressure in different permeability values.

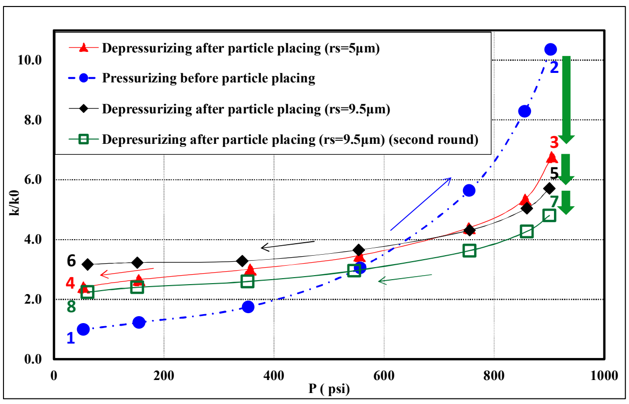


Figure 5. Permeability versus pore pressure before and after the proppant placement tests.

Figure 5 shows the results of the tests for core C_1, which are carried out for salinity and pH values of 0.05 M and 9, respectively. The initial permeability at low pressure ($p = 50$ psi, which corresponds to an effective stress of 945 psi) is equal to 0.37 mD. The blue injection line increases permeability up to 3.88 mD at $p = 900$ psi (that corresponds to an effective stress of 188 psi). Injection of 5 μm proppant particles yields permeability decreases up to 2.53 mD. The return red curve exhibits the permeability enhancement due to particle injection at high pressure and keeping the cleats open at lower pressures. The red curve ends up at a permeability of 0.9 mD, showing the enhancement against the initial core permeability of 0.37 mD.

Further injection of 9.5 μm proppant particles at the highest pressure causes a further decrease of permeability from 2.53 mD to 2.14 mD. The pressure decrease return is shown by the black curve. Further permeability increase from 0.9 mD to 1.19 mD occurs at the initial pressure.

A secondary injection of 9.5 μm proppant (green curve) decreases the effect of the remaining cleat aperture by strained proppant—the green curve comes back at almost the same permeability as the red curve.

Injection of 5 μm proppant particles keeps the cleat open during pressure depletion and causes permeability increase. Injection of larger particles (9.5 μm) at high pressure results in further enhancement of the cleat aperture and further permeability increase. Secondary large-particle injection yields the increase of the strained particle density in the cleats, which leads to the increased hydraulic resistivity with consequent permeability decline. An optimal concentration of size-excluded particles placed in cleats that yields the maximum return permeability, therefore, exists.

2.4 Optimum concentration of placed particle

Two competitive mechanisms affect the permeability of the cleat network after particle placement:

1. the reduction in fracture aperture due to gradually increasing effective stress; and,
2. additional tortuosity of the flow path created by the presence of placed proppant particles.

Dense packing of the proppant particles minimises the deformation of the fracture, whereas sparse packing minimises additional tortuosity to the flow path. To minimise the net negative effect of the above mechanisms, an appropriate proppant concentration at which fracture conductivity reaches its maximum value should be determined. Several parameters affect this optimal proppant concentration, including the:

- maximum effective stress;
- rock properties (i.e. Young's modulus, Poisson's ratio and rock compressibility); and,
- mechanical strength of the proppant.

Khanna et al (2013) developed a semi-analytical mathematical model to calculate the optimal proppant concentration in narrow fractures. A correction factor—$f(\beta, \varepsilon_\sigma)$—was proposed, such that the fracture permeability after proppant placement is $k_{fr}^{prop} = f(\beta, \varepsilon_\sigma) \times k_{fr}$. This correction factor is a function of two dimensionless parameters:

1. the dimensionless optimum particle packing aspect ratio, ($\beta = 2r_p/L$), where r_p is the particle radius, and L is the particle distance; and,

2. dimensionless stress, $\varepsilon_\sigma = \frac{\sigma_e(1 - \nu^2)}{E}$.

In the second dimensionless parameter, σ_e is effective stress, ν is Poisson's ratio, and E is Young's modulus.

The particle packing aspect ratio (β) is the areal particle concentration in the fracture system. When it is equal to zero, it means zero particle concentration; and when it is equal to 1, it implies that the fracture system is fully packed by particles. For each rock characterised by its unique value—ε_σ—therefore, it is possible to calculate an optimal particle concentration at which the correction factor, $f(\beta, \varepsilon_\sigma)$, is at its maximum value. In this study parameters β and $f(\beta, \varepsilon_\sigma)$ are calculated experimentally.

In the proppant placement tests (section 2.3) the accumulated breakthrough particle concentrations are measured after each of the three injections. Since the injected proppant concentration is known, it allows for determining the concentration of placed proppant particles and, consequently, the aspect ratio coefficient (β) as follows.

In this section a model has been developed to calculate the aspect ratio coefficient (β) based on the experimental data. This method has been developed based on the assumption of the matchstick geometry of matrix blocks in coal core.

Equations 1 and 2 are formulae for fracture permeability and porosity in a matchstick arrangement of matrix blocks (Fig. 6a). Average values for fracture opening (h) and fracture spacing (a), therefore, are found from Equations 1 and 2 when values of $\O_f$ and k_f are measured experimentally.

To find the total fracture surface of the sample, an equivalent fracture width (w; Fig. 6b) is found using Equation 3.

$$w = \frac{\O_f V_b}{hL} \tag{3}$$

In Equation 3, V_b is the bulk volume of the core sample. The total number of particles (N_{Tp}) that can be placed in the fractures (Fig. 6c), therefore, can be determined with Equation 4.

$$N_{Tp} = \frac{wL}{(2_{rp})^2} \tag{4}$$

N_p is the number of particles that are placed inside the fractures. This parameter is calculated based on the material balance of the concentration of injected suspension fluid and concentration of effluent (which is measured by a particle counter). In Equation 5, ϵ is the number of placed particles per total rooms inside the fractures.

$$\epsilon = \frac{N_p}{N_{Tp}} \tag{5}$$

In Equation 6, γ is the average of room numbers per two adjacent particles inside the fractures (Fig. 6d).

$$\gamma = \frac{2}{\epsilon} \tag{6}$$

L_Δ in Equation 7 is the average distance between two adjacent particles (Fig. 6d).

$$L_\Delta = \gamma(2r_p) - 2r_p = 2r_p(\gamma - 1) \tag{7}$$

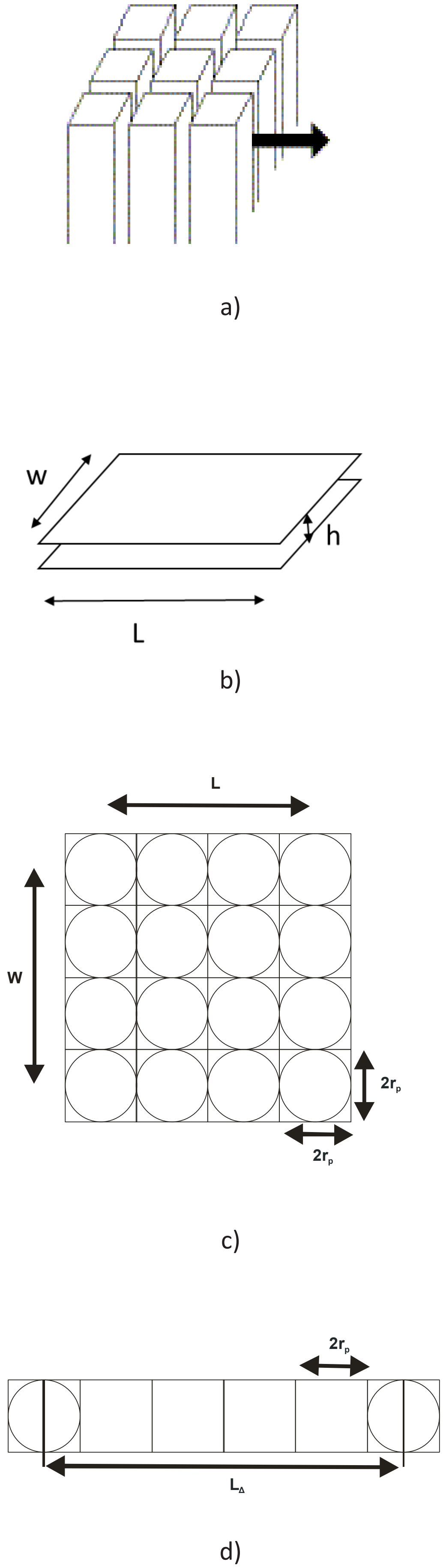


Figure 6. a) Matchstick geometry of matrix blocks. b) Equivalent fracture. c) Fracture surface fully occupied by placed proppant particles. d) Partially placed proppant particles in the fracture.

In Equations 8 and 9, β is the dimensionless aspect ratio.

$$\beta = \frac{2r_p}{L_\Delta} \tag{8}$$

$$\beta = \frac{2r_p}{L_\Delta} = \frac{2r_p}{2r_p(\gamma - 1)} = \frac{1}{\gamma - 1} \tag{9}$$

The dimensionless aspect ratio (β) values calculated by Equation 9 are presented in Table 2 for all three particle placement tests (Fig. 5).

After determination of β in each particle placement test, the permeability correction factor $f(\beta, \varepsilon_\sigma)$ in each effective stress was calculated using Equation 10.

$$f(\beta, \varepsilon_\sigma) = \frac{k(\beta, \varepsilon_\sigma)}{k(0, \varepsilon_{\sigma min})} \tag{10}$$

Figure 7 illustrates the permeability correction factor $f(\beta, \varepsilon_\sigma)$ versus the dimensionless aspect ratio (β) in different states of dimensionless stress ε_σ. Based on the results of the proppant injection tests (Fig. 5), points 1 to 7 in Figure 7 for β_1, β_2 and β_3 correspond to permeability correction factors at different effective stresses after the injection of 5 µm proppant, and the first and second injections of 9.5 µm proppant, respectively. Points with the same number have the same ε_σ. Points 1 lie on the envelope because permeability reduction in these points is only due to proppant placement at minimum effective stress. These points correspond to experimental points at minimum effective stress after proppant placement in Figure 5. Points 7 correspond to permeability points at maximum effective stress in Figure 5. The iso-ε_σ curves are plotted by fitting polynomial curves. The fitting results are shown in Figure 7. The maximum point in each iso-ε_σ curve determines the optimum aspect ratio (β*), in which maximum $f(\beta, \varepsilon_\sigma)$ is achieved. Points 2' to 7' in Figures 7 and 8 correspond to maximum permeability correction factors in different dimensionless effective stresses (ε_σ). Figure 8 illustrates that the maximum permeability correction factor is a linear function of the dimensionless effective stresses (ε_σ) in the proppant placement tests.

Table 2. Proppant aspect ratios in different placement tests.

Placement test number	r_p (µm)	β
1	5	0.137
2	9.5	0.216
3	9.5	0.285

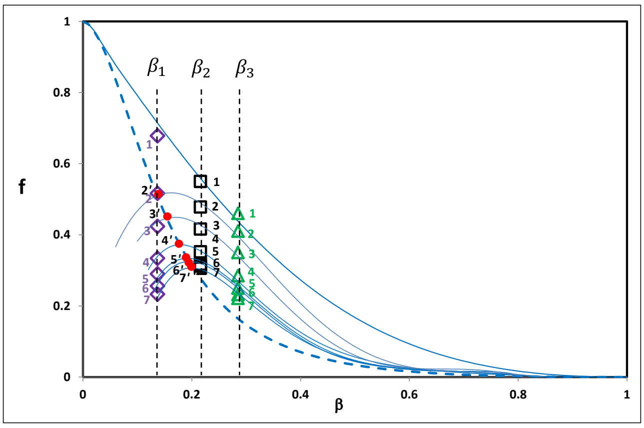


Figure 7. Permeability correction factor versus the dimensionless proppant aspect ratio in different states of dimensionless stress.

3. MATHEMATICAL MODELLING

In this section an analytical model is developed for the stimulation of the cleat system and micro-fractures around the main hydraulic fracture by placing different-sized proppant particles in the fracture system. The model presents linear flow in stress-sensitive rocks before proppant placement, and permeability and cleat aperture distributions (section 3.1). In section 3.2 the proppant placement strategy is developed. Alternated pressure and permeability distributions after proppant placement are presented by including the experimental coefficient into the model. Explicit formula for the productivity index after proppant placement is given in section 3.3. Section 3.4 conducts a parameter study using real data.

The assumptions of the model include:

- linear flow from the fracture network towards the main fracture;
- Darcy's law for the flow of injected suspension;
- the particle and water velocities values being equal;
- steady-state pressure including the incompressibility of water and proppant particles;
- the exponential stress dependence of permeability; and,
- the proportionality of permeability to the cube of the fracture aperture.

3.1 Linear flow in stress-sensitive rocks

In CBM reservoirs permeability is a function of effective stress (Pan and Connell, 2012; Seidle, 2011), as shown in Equation 11.

$$k(p) = k_0^{[3C_f\alpha(\sigma_e - \sigma_{e0})]} \tag{11}$$

In Equation 11, permeability (k_0) corresponds to the initial effective stress (σ_{e0}), C_f is the fracture compressibility, and Biot's constant (α) is a multiplier in the Terzhagy formula (Biot, 1941; Terzaghi, 1923) shown by Equation 12.

$$\sigma_e = \sigma - \alpha p \tag{12}$$

Here σ_e is the effective stress, and σ is the confining stress. Assuming constant confining stress σ, the permeability formula (Eq. 11) simplifies to Equation 13.

$$k(p) = k_0^{[3C_f\alpha(p - p_0)]} \tag{13}$$

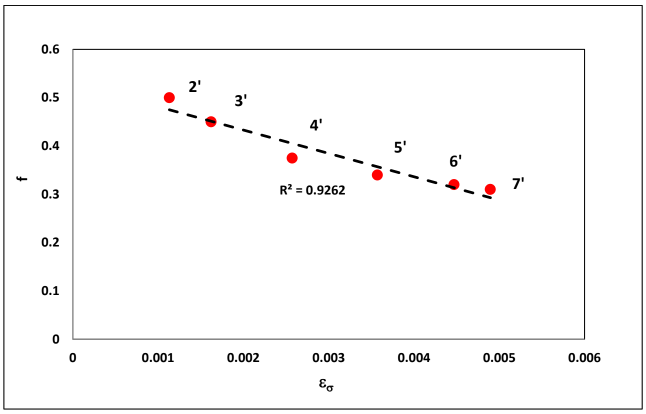


Figure 8. Permeability correction factor versus the dimensionless stress at the optimum dimensionless aspect ratios.

In Equation 13 p and p_0 are reservoir pressure and initial reservoir pressure, respectively.

To determine the permeability and cleat aperture during fluid injection into the natural fracture system around a hydraulically induced fracture, the distribution of pressure must first be determined. Assuming isotropic permeability, the distribution of pressure in the reservoir can be found using the linear Darcy equation (Eq. 14).

$$q = -\frac{k(p)A}{\mu}\frac{dp}{dx}\ , \ A = 4L_f \times h \tag{14}$$

In Equation 14, L_f is fracture length and h is fracture height.

Substituting the permeability expression (Eq. 13) into Equation 14, separating variables and integrating accounting for the reservoir pressure at the drainage zone boundary, yields the pressure distribution during either injection or production as shown in Equations 15 and 16.

$$p_{inj} = p_0 + \frac{1}{3\alpha C_f}\ln[1+\varepsilon_{qi}(L-x)]\ ,\ \ \varepsilon_{qi} = \frac{3\alpha q_{inj}\mu C_f}{4k_0 hL_f} \tag{15}$$

$$p_{pro} = p_0 + \frac{1}{3\alpha C_f}\ln[1-\varepsilon_{qp}(L-x)]\ ,\ \ \varepsilon_{qp} = \frac{3\alpha q_p\mu C_f}{4k_0 hL_f} \tag{16}$$

By constituting Equations 15 and 16 into Equation 13, the permeability distributions during fluid injection (Eq. 17) and production (Eq. 18) are found.

$$k_{inj}(x) = k_0[1+\varepsilon_{qi}(L-x)] \tag{17}$$

$$k_{pro}(x) = k_0[1-\varepsilon_{qp}(L-x)] \tag{18}$$

The fractured system permeability is proportional to the cube of the fracture aperture (Reiss, 1980; van Golf-Racht, 1982), as shown in Equation 19.

$$\frac{k}{k_0} = \left(\frac{h}{h_0}\right)^3 \tag{19}$$

Substituting Equation 17 into Equation 19 yields the fracture aperture distribution during the fluid injection (Eq. 20).

$$h(x) = h_0\left(\frac{k(x)}{k_0}\right)^{\frac{1}{3}} = h_0[\varepsilon_{qi}(L-x)+1]^{\frac{1}{3}} \tag{20}$$

The injection of a proppant suspension in water will now be discussed. It is assumed that the particle is trapped in a fracture when its aperture reaches the value of particle diameter, $h = 2r_p$. As it follows from Equation 20, the particle with radius r_p is trapped at the distance $x = x(r_p)$ (Eq. 21).

$$x(r_p) = \left[L - \frac{1}{\varepsilon_{qi}}\left(\left(\frac{2r_p}{h_0}\right)^3 - 1\right)\right] \tag{21}$$

The length of the stimulated zone (x_{st}) corresponds to the minimum size of particles (Fig. 1) as follows in Equation 22.

$$x_{st} = x(r_{p\min}) = \left[L - \frac{1}{\varepsilon_{qi}}\left(\left(\frac{2r_{p\min}}{h_0}\right)^3 - 1\right)\right] \tag{22}$$

3.2 Linear flow with placed proppant particles

As shown in section 2.4, by optimised particle placement inside the fracture system, permeability decreases as $k_{fr}^{prop} = f\,[\beta^*(\sigma_e),\ \varepsilon_\sigma(\sigma_e)] \times k_{fr}$. Parameters β^* and ε_σ are just pressure-dependent parameters by assuming confining stress is constant. Permeability formulas during production inside and outside of the stimulated zone around the hydraulically induced fracture, therefore, are calculated using Equation 22.

$$k_{pr}(x) = \begin{cases} f\,[\beta^*(p),\ \varepsilon_\sigma(p)] \times k_{in}(x) & x \le x_{st} \\ k_{pro}(x) & x > x_{st} \end{cases} \tag{23}$$

In Equation 22, $f\,[\beta^*(p(x)),\ \varepsilon_\sigma(p(x))]$ is a linear function of reservoir pressure in each length (x), which is found from the experimental results (Fig. 8). $k_{in}(x)$ and $k_{pro}(x)$ are calculated from Equations 17 and 18, respectively.

Substituting the expression for permeability (Eq. 23) into the stimulated zone (Eq. 14), separating variables and integrating in x from the point $x < x_{st}$ up to the stimulated zone boundary, yields the following formula (Eq. 24) for pressure distribution in the stimulated area around the hydraulically induced fracture.

$$\int_{p_x}^{p_{st}} f\,[\beta^*(p),\ \varepsilon_\sigma(p)]\,dp = \frac{q_p\mu}{4L_f hk_0}\int_x^{x_{st}} \frac{1}{1+\varepsilon_{qi}(L-x)}\,dx \tag{24}$$

3.3 Productivity index

To evaluate the proposed method, productivity index values for before and after proppant placement have to be calculated and compared with each other.

The productivity index before proppant placement is calculated by substituting Equation 18 into Equation 14, giving Equation 25, where p_f is the pressure at the fracture walls.

$$PI_0 = \frac{q_p}{p_0 - p_f} = \frac{q_p}{\frac{-1}{3\alpha C_f}\ln[1-\varepsilon_{qp}(L)]} \tag{25}$$

The well productivity index after the proppant placement is given by Equation 26.

$$PI = \frac{q_p}{(p_0 - p_{st}) + (p_{st} - p_f)} \tag{26}$$

In Equation 26, the fracture wall pressure (p_f) value is determined from Equation 24 by substituting $x = 0$. The term ($p_0 - p_{st}$) in Equation 26 is the pressure drop between the drainage and stimulated zone. It is defined by Equation 16. Term ($p_{st} - p_f$) in Equation 26 is the pressure drop across the stimulated zone, which is determined by Equation 24.

3.4 Case study

Figure 9 shows the normalised productivity index versus stimulated length for different fracture compressibility values. The initial data for productivity index evaluation are adopted from the Southern Qinshui Basin (Meng et al, 2011). As the target is stimulating natural fractures and cleats around hydraulically induced fractures, the injection pressure in Figure 9 for all scenarios is equal to the breakdown (fracturing) pressure (Economides et al, 2002) as follows in Equation 27.

$$p_b = 3\sigma_h - \sigma_H - p_{res} + T^* \quad (27)$$

p_b is the breakdown (fracturing) pressure, σ_h is the minimum horizontal stress, σ_H is the maximum horizontal stress, p_{res} is the reservoir pressure, and T^* is the tensile strength.

As shown in Figure 9, by applying this technique the productivity index can be improved by up to about six times in the stimulated zone, x_{st} = 0.05L. The larger the stimulated zone is, the higher the productivity index value is after stimulation. In addition, the higher the fracture compressibility is, the higher the productivity index gets. It means that this method displays better performance in more stress-sensitive reservoirs.

4. DISCUSSIONS

As permeability in CBM reservoirs is pressure dependent, pressure decline during production, which results in the deformation of the matrix and fractures, leads to significant permeability reduction (Palmer, 2009). This permeability reduction in the fracture system around hydraulically induced fractures may decrease the efficiency of the hydraulic fracturing treatment. Any process that improves or maintains the conductivity of cleat networks surrounding the main hydraulic fracture, therefore, could significantly increase the efficiency of hydraulic fracturing in CBM reservoirs.

Stimulation of micro-fractures and the cleat system around hydraulically induced fractures is achieved by enhancing the rock permeability by graded proppant placement. This technique is evaluated using the custom-built experimental set up. The experimental procedure consists of injection of low-salinity water through a fractured coal sample with piecewise gradual increase of the pore pressure, injection of suspended particles at maximum pore pressure—which correspond to maximum fracture permeability—and injection of proppant free water under a gradually decreased pore pressure. This simulates the proppant placement process in the fracture system around hydraulically induced fractures during the leak-off stage with further reservoir dewatering.

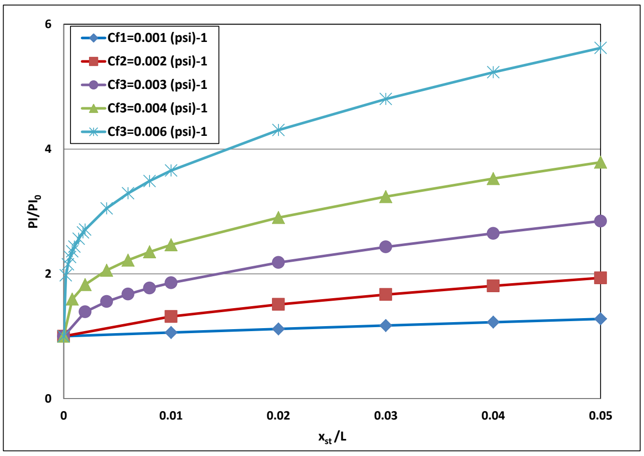


Figure 9. The productivity index versus the stimulated length after proppant placement.

The proposed laboratory-based mathematical model for the stimulation of natural fractures and cleats around the hydraulically induced fracture by graded proppant placement has numerous limitations. A more complicated model for suspension flow and proppant capture in fracture media permeability may enhance the reliability of the model. For instance, the model does not account for the retention of different-sized particles, for cleat opening size distribution, or for the filtration path tortuosity. The population balance model can be applied for permeability prediction after injection of multi-sized suspension (Bedrikovetsky, 2008; Zitha and Du, 2010). The cleat geometry and fracture network topology can be captured by percolation and effective medium theory (Bedrikovetsky, 1993; Shapiro, 2007). The above mathematical model would optimise the injected proppant concentration, size distribution and the detailed injection schedule with more reliable behaviour prediction.

During the dewatering or gas production stages, flowing fluid may entrain previously placed particles in the natural fracture system and move them towards the main hydraulic fracture (proppant backflow), resulting in the decrease of well stimulation efficiency. By maintaining low production rates at the initial stage of dewatering (minimum effective stress), this undesirable effect can be eliminated or reduced by not dislocating the placed particles. Additionally, pressure reduction in the reservoir during dewatering causes a cleat network to deform but not to collapse due to optimal placement of particles in the cleats. This prevents the removal of previously placed particles, and enhances coal cleat permeability.

5. CONCLUSION

This paper's mathematical modelling and experimental study on proppant particle placement in a cleat network surrounding a hydraulically induced fracture draws the following conclusion.

A new method was proposed for the stimulation of a naturally fractured system in conjunction with hydraulically induced fractures to increase the efficiency of the hydraulic fracturing treatment.

A laboratory-based mathematical model for studying the graded proppant injection in the fracture system around the main fracture was developed. The case-study conducted using typical CBM reservoir data demonstrates that this technique may lead to well productivity enhancement.

Different-sized proppant placement tests result in about a threefold permeability enhancement for the core sample investigated. It yields up to about a sixfold well productivity enhancement.

The most influential parameters affecting the performance of the stimulation method are fracture compressibility and the stimulation zone size. The higher the values are for fracture compressibility and stimulation zone size, the higher the productivity index is.

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Authors' biographies next page.

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Chapter 6

Summary and conclusions

Summary and conclusions:

This thesis presents a new stimulation technique, called graded proppant injection, in order to improve permeability of natural fracture systems. The purpose of the proppant injection into a natural cleat system is to keep cleats open during gas production when pore pressure declines with time. Experimental studies and laboratory-based mathematical models are developed to validate the new technology for enhanced gas recovery. The proposed method has been applied to real field conditions to predict productivity enhancement during graded proppant injection.

The first two papers describe the proposed graded proppant injection technique, i.e. the injection of particles of increasing size and decreasing concentration, for stimulation of natural fracture rocks. Basic equations for suspension flow in natural fracture rocks were derived. Stress dependent permeability models were used to predict well productivity enhancement as the result of this stimulation technique. Mathematical models for graded proppant injection were developed describing the injection stage and capture kinetics of proppant particles in natural fracture systems. Real field data used for sensitivity analyses and parameter studies showed that the most influential parameter affecting the proppant injection schedule and well productivity index is the fluid injection rate. A higher injection rate results in greater cleat aperture, deeper percolation of particles, shorter injection time and a greater increase in well productivity. It was also found that there is an optimal stimulation radius in which the maximum productivity index is achieved by applying the graded proppant injection technology.

The technique of graded proppant injection below the fracturing pressure has been experimentally evaluated by injection of micro-sized particles into coal cores (papers 3, 4 and 5). A custom-made core-flooding system has been developed for performing these experiments. The laboratory tests on one-dimensional injection of different sized particles into coal cores have been conducted under different effective stress conditions. Electrostatic interaction studies have been done to determine the physico-chemical conditions, favourable for particle-particle and particle-coal repulsion. The DLVO theory is used to study the effects of salinity and pH of suspensions on particle-particle and particle-coal electrostatic interactions. It was observed that particle injection with high salinity water does not increase coal permeability due to particle-rock attraction and particle agglomeration, causing the build-up of external and internal cakes near to core inlet thus preventing particle deep bed penetration. On the contrary, using low-salinity water with the particle-coal and particle-particle repulsions yields particle penetration into naturally-fractured coal with the consequent return permeability increase (papers 3 and 4). However, low salinity of the injected water may cause mobilisation, migration and straining of natural reservoir fines resulting in significant formation damage. Therefore, experimental studies were conducted to observe the effect of salinity variations on fines migration in coal. The goal of these studies was to determine an interval when salinity is low enough in which coal inlet is not plugged by the injected proppant, and is sufficiently high to avoid significant formation damage due to fines migration (paper 5). It was observed that the salinity interval favourable for particle-coal repulsion and insignificant fines migration for the studied coal samples is 0.1–0.05 M. Injection of low salinity proppant-based suspension resulted in 3.0–3.2 times permeability enhancement for the used coal samples.

An empirical parameter called "permeability shape factor" was introduced (paper 4). Implementation of the permeability shape factor allowed matching the laboratory data by the mathematical model developed in paper 1. The proposed mathematical model was tuned using experimental data and applied to field conditions showing a significant increase in well productivity index. It was also shown that ignoring model matching by the laboratory data leads to an overestimation of the incremental well productivity index during graded proppant injection into coal beds below the fracturing pressure.

An improved laboratory-based mathematical model was developed in the paper 5. The analytical model for axisymmetric flow was derived for exponential stress-permeability relationship and accounting for permeability variation outside the stimulated zone. Matching this mathematical model with the experimental data allowed for reliable experiment-based behaviour prediction for the wells subjected to graded proppant injection. The sensitivity analysis performed for well productivity index showed that the most influential parameters are the stimulated zone size, injection pressure and the cleat system compressibility. The laboratory-based mathematical modelling as performed for the field conditions showed that the proposed method can yield up to 3-5 times increase in well productivity index.

The proposed graded proppant injection technique was coupled with hydraulic fracturing treatment to stimulate natural cleat network and micro fractures around hydraulically induced fractures (paper 6). It allows the graded proppants to enter into surrounding cleats under leak-off conditions and consequently increase the efficiency of hydraulic fracturing in CBM reservoirs. A laboratory-based mathematical model for graded proppant placement in naturally fractured rocks around a hydraulically induced fracture was proposed. The model was developed based on linear flow from fracture network towards the main fracture in stress sensitive rocks before and after proppant placement. Alternated pressure and permeability distributions after proppant placement were presented by including an experimental coefficient into the model. Field case studies were performed to evaluate the enhancement of well productivity index by coupling the graded proppant injection technique with hydraulic fracturing treatment. Different sized proppant placement tests resulted in about 3 times permeability enhancement for the investigated core sample. It yielded up to about 6 times well productivity enhancement.

The above experimental study, mathematical modelling and field-case predictions allow recommending the developed stimulation technology of graded proppant injection for gas recovery enhancement from coal bed methane reservoirs.