Fuel 203 (2017) 843–852

Contents lists available at ScienceDirect

Fuel

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

A sensitivity analysis of the effect of pumping parameters on hydraulic fracture networks and local stresses during shale gas operations

Rachel F. Westwood *, Samuel M. Toon, Nigel J. Cassidy [1]

School of Geography, Geology and the Environment, Keele University, Keele, Staffordshire ST5 5BG, United Kingdom

HIGHLIGHTS

- First parametric modelling study of shale gas fracking using operational parameters.
- Flow distance and fracture area can be controlled using pump time at dP < 2 MPa.
- Evaluation of lateral distance for safe fracking to minimise felt seismicity.
- Reducing lateral distance needs a compromise with flow distance and fracture area.

ARTICLE INFO

Article history:
Received 11 January 2017
Received in revised form 25 April 2017
Accepted 2 May 2017

Keywords:
Hydraulic fracturing
Numerical modelling
Pumping parameters
Stress
Shale gas
Faulting

ABSTRACT

The shale gas industry has significant impact on economies around the world, however, it is not without risk. One of the primary concerns is felt seismicity and recent earthquakes, caused by fault reactivation related to hydraulic fracturing operations, have escalated uncertainty about hydraulic fracturing methods. Mitigating these risks is essential for restoring public confidence in this controversial industry. We investigate the effect that changing two operational parameters (flow rate and pumping time) and differential pressure have on the flow distance, fracture network area and the minimum lateral distance that hydraulic fracturing should occur from a pre-existing fault in order not to reactivate it (lateral respect distance); thus reducing the risk of felt seismicity. Sensitivity analyses are conducted using a Monte Carlo approach. The lateral respect distance is obtained from calculations of the Coulomb stress change of the rock surrounding the injection stage, for four stress threshold values obtained from the literature. Results show that the flow rate has the smallest rate of change for fracture area (3700 m^2 per 0.01 m^3/s) and flow distance (8.3 m per 0.01 m^3/s). We find that differential pressure has the largest impact on stimulated fracture area, when less than 2 MPa, at 31,029 m^2/MPa. The pumping time has the most significant effect on the flow distance (48 m/h) and the stress threshold value the most significant effect on the lateral respect distance. This study suggests that to reduce the lateral distance, a compromise is required between flow distance and fracture area. The results obtained by this research provide invaluable guidance for operational practice in determining the potential area of the induced fracture network and generated stress field under realistic hydraulic fracturing conditions, an important aspect for risk assessments.

1. Introduction

Hydraulic fracturing for shale gas is a controversial energy option and not without risks. In the UK alone, the Shale Gas economy is estimated to be valued at four billion pounds per year [1], but there are significant concerns about the environmental impact on its development within a national context [2]. Felt seismicity is one of the primary concerns and in April-May 2011, public anxiety increased as hydraulic fracturing of the UK's first well for shale gas exploration, near Blackpool in Lancashire, caused two felt earthquakes (M_L 2.3 and 1.5) [3,4]. Just prior to this, felt seismic events due to hydraulic fracturing operations had also been experienced in the Eola Field in Oklahoma, USA [5] and the Horn River Basin in British Columbia, Canada [6]. Later, in 2013, hydraulic fracturing operations caused felt seismicity in Doe-Dawson, British Columbia, Canada [7] and Ohio, USA, where there have been a number of

* Corresponding author at: Learning and Professional Development Centre, Keele University, Keele, Staffordshire ST5 5BG, United Kingdom.

E-mail addresses: r.f.westwood@keele.ac.uk (R.F. Westwood), s.m.toon@keele.ac.uk (S.M. Toon), n.j.cassidy@bham.ac.uk (N.J. Cassidy).

[1] Present address: School of Engineering, University of Birmingham, Edgbaston, Birmingham B15 2TT, United Kingdom.

http://dx.doi.org/10.1016/j.fuel.2017.05.004
0016-2361/

'unusual' events [8,9]. More recently, Crooked Lake in Alberta, Canada has experience a sequence of 160 events [10]. Events greater than M4.0 have been observed near Fox Creek, Alberta [11,12] and Fort St James in British Columbia [13].

There have been a number of events in Ohio, Arkansas and Oklahoma, associated to shale gas operations, but which were a consequence of re-injection of wastewater [14,15]. Hundreds of thousands of shale gas hydraulic fracturing episodes have occurred without issue; however, it is these few instances of felt seismicity that the public remembers. It is, therefore, essential that the risks and uncertainty are fully understood and minimized in order to restore public confidence in the exploration and exploitation of shale gas and hydraulic fracturing. This is particularly the case in the UK, where permission has recently been granted for a number of exploratory wells.

The detection of the minimum resolvable fault displacement can depend on a number of factors. However, current 2D seismic reflection technology has detected faults in coal mining with a throw as small as 4–5 m [16]. This allows operators to evaluate the surrounding geology and assess the current stress state, location, size and criticality of any weaknesses and the possibility of these slipping when a change in stress is applied. The magnitude of any induced event that occurs along a fault can be estimated using Kanamori and Anderson's [17] relationship between magnitude and fault size, constrained by slip length. The maximum magnitude of events normally associated with hydraulic fracturing would have a rupture length of less than a few hundred metres and a slip of only millimetres [18].

The process of hydraulic fracturing creates a network of new induced fractures and reactivated dilated pre-existing natural fractures. Fractures propagate in the plane containing the maximum and intermediate stresses. By analysing data of microseismic event clouds from thousands of hydraulic stimulations, two papers have agreed that the vertical extent at which hydraulic fractures extend is less than 600 m from the well perforation [20,21]. An initial numerical modelling study to examine the lateral distance of the Coulomb stress change from hydraulic fracturing operations and the effect that this may have on pre-existing faults was presented in Westwood et al. [19]. The study adopted a Monte Carlo approach and showed that it is the failure threshold that has the most significant impact on the horizontal respect distance (the minimum lateral distance that hydraulic fracturing should occur from a pre-existing fault in order not to reactivate it), with values ranging from 63 m to 433 m depending on the combination of fracture intensity and failure threshold. Vasuvedan and Eaton [22] demonstrated that Coulomb stress analysis could be applied to hydraulic fracturing using a source mechanism of a combination of strike-slip and reverse movement. The modelling work of Rutqvist et al. [23] found that shear and tensile failure occur simultaneously and that, when a fault is present, events are larger than the small microseismic events generated by the hydraulic fracturing process. Yoon et al. [24] modelled the response of a geothermal reservoir, using Discrete Element Modelling, to fluid injection and found that cyclic pumping rather than a constant pump rate decreased the occurrence of induced seismicity.

Sensitivity studies have investigated whether the total fracture volume, aperture, and porosity are sensitive to the fracture length [25] and the effect that cohesion, the in situ-stress ratio, the internal friction angle [26] and injection rate [26,27] have on the natural fractures. It was found that the total fracture volume, aperture, and porosity are not sensitive to the fracture length. The injection rate impacts on fracture complexity, with an increased rate increasing the stimulated fracture area [26] and fracture length [27]. Cohesion, internal friction angle and the in situ-stress ratio all affect the morphology of the fracture network, with fractures orientated toward the maximum stress direction enhancing the fracture network complexity [26]. All of these results were based on one Discrete Fracture Network (DFN), rather than applying a Monte Carlo approach.

In this paper we investigate some of the issues that were not addressed by previous analyses and focus on the application of operational-related parameters (such as flow rate) that have direct relevance to real-world Shale Gas operation across the globe. We conduct sensitivity analyses by applying a Monte Carlo approach that investigates the effect that pumping time and differential pressure at injection have on 1) fracture area, 2) maximum flow distance and, 3) the lateral respect distance that hydraulic fracturing should occur from a fault in order that it is not reactivated. In addition, we also apply the same method to investigate the effect that the flow (or injection) rate has on these three parameters. The model and these methods are described in Section 2, whilst in Section 3, we present the results and discuss the effect and implications of them in Section 4, before providing concluding remarks in Section 5.

2. Methods

We apply the numerical modelling approach described by Westwood et al. [19], which uses Golder Associates' Fracman 7.5 software to generate discrete fracture networks (DFN) to model natural and induced fracturing in a 3D geological volume. Hydraulic fracture simulations are run on the DFN to obtain a network of opened natural and newly created hydraulic fractures. The DFN, geological, fracture and stress parameters used in the model are provided in Table 1 and the model design is shown in Fig. 1. The elastic properties are homogeneous across the layer. The model is based on the geology at Preese Hall, near Blackpool, in the northwest of England, UK. The stresses are based on those published for the Bowland and Worston Shale formations [28]. The shales lie at a depth between 1957 m and 2690 m, with a 60 m layer of limestone sandwiched between them, with its top at 2479 m. Above the Bowland shale formation lies Millstone Grit and below the Worston shale, the Clitheroe limestone complex (Table 2).

The exact fracture intensity in this region is unknown, therefore we use a fracture intensity based on the findings of Westwood et al. [19], with a P32 (area of fractures per unit volume) of 0.15, the value which generated the largest lateral respect distance of the three values used by Westwood et al. [19]. The stress regime is defined to be strike-slip. The values of σ_H, σ_h and σ_v are obtained from those derived in the reports commissioned by Cuadrilla following hydraulic fracturing at Preese Hall [28–31]. Young's modulus is calculated from the shear and bulk modulus derived in [31] and is slightly higher than some of the shales of North America [19]. The value for Poisson's ratio is comparable to the Barnett shale [32].

Three sets of parameters are considered and calculated for a range of values. These are:

1. Differential pressure (dP). This is "the pressure difference between pore pressure and normal pressure on the fractures at injection" [33]. A parametric study is performed every 1.5 MPa from 0.676 MPa (equivalent to an instantaneous shut-in pressure (ISIP) of 37.5 MPa at Preese Hall) to 11.176 MPa (ISIP = 48 MPa at Preese Hall). This was further refined to every 0.25 MPa between 0.676 MPa and 2.926 MPa. This range was selected from the ISIP values obtained at the Preese Hall well from minifrac and formation integrity tests (FIT) [30].

For all simulations:

- Flow rate = 0.117 m^3/s