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Hydraulic fracture permeability estimation using stimulation pressure data

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ABSTRACT

We describe a method, first proposed by Sil and Freymueller in 2006, to estimate permeability of hydraulic fracture from pressure data recorded during hydraulic fracturing. The method hypothesizes that the drop in the injection pressure just after the breakdown during hydraulic fracturing occurs due to flow of injected fracturing fluid inside the induced hydraulic fracture. If this is true than the fracture permeability can be estimated using diffusion equation. To test the hypothesis the pressure data recorded just after the breakdown during hydraulic fracturing of dry Tennessee sandstone is modelled with 1D pressure diffusion equation. The outcome of modelling is the value of hydraulic diffusivity which is used to estimate fracture permeability. Hydraulic diffusivity is a function of permeability, injected fluid viscosity and poroelastic modulus of rock. The injected fluid viscosity is most of the time known and the poroelastic modulus can be calculated from the velocity data measured in the lab. To validate the results, the estimated fracture permeability was compared with the fracture permeability measured as a function of confining pressure using AP608™. The results show that the estimated permeability values come in close agreement with the measured one at 500 psi.

1. Introduction

Hydraulic fracturing technique has been used for past sixty years to exploit hydrocarbons resources. We still lack the complete understanding of the processes that creates the fracture and the stimulated zone around it. Since the technique is imperative for economic exploitation of tight-gas and shale-gas reservoirs, it is necessary to optimize the technique by optimizing the processes that governs it. Over the last two decades microseismic has become the most common method to monitor effectiveness of the stimulation job. To get more understanding of the fracture mechanics one of the task of the professionals working in the energy industry has been to deduce more information than just effectiveness of the job from the various kind of data recorded during hydraulic fracturing. Thus, methods have been developed to shed light on fracture mechanics[1–4] and reservoir and fracture permeability[5–10] using microseismic. Also, methods have been developed to estimate reservoir parameters such as permeability, fluid mobility and formation transmissibility using hydraulic fracturing injection pressure data.[11–13]

Two methods have been published recently to estimate permeability from microseismic.[8,10] One of the method derives permeability using rate of growth of microseismic cloud and the other method uses geometry of the microseismic cloud. Both the method depends on the precise location of the microseismic. Moreno[14] estimated permeability using both the methods from acoustic emission data recorded during triaxial hydraulic fracturing experiment and compared the value of permeability with the measured one. He observed inconsistencies between values estimated using above mentioned methods and those obtained experimentally. The estimated values were two to three orders less than the measured one. According to Moreno,[14] the permeability values estimated using the later method are affected by the uncertainties in the location since they affect the aspect ratio. The inconsistencies in permeability values estimated using rate of growth of microseismic cloud was due to erroneous value of diffusivity used in permeability calculation. The incorrect value of diffusivity arose because it was calculated using events falling in the quasi linear fracture growth behavior which actually should be omitted.[10,14]

Microseismic is a powerful tool but it has lot of uncertainties inherent to it. Thus, there has been always a need to validate the results obtained using it whether it is permeability, stimulated reservoir volume or dimensions of the fracture. One of the other form of data that is recorded in all the hydraulic fracturing jobs and can be useful is the injection pressure data. Injection pressure data has been used recently in technique called After Closure Analysis (ACA) to estimate formation properties.[13] We present a technique in this paper which uses injection pressure data to estimate permeability of hydraulic fracture. The technique is like the one used in earthquake seismology where the transient change in water level is used to estimate enhanced permeability of the reservoir caused by passing surface wave.[15] Also, we have not yet completely understood the flow of fracturing fluid during hydraulic fracturing. To optimize the fracturing, it is very important to

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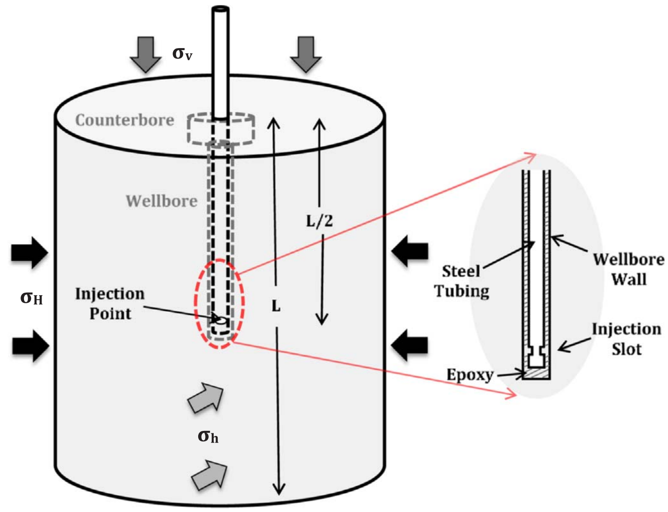

Fig. 1. Schematic of the sample used for hydraulic fracturing. The steel tubing is cemented in the cylindrical sample in such a way that the injection point is exactly at the centre of the sample. The experiments are conducted under the stress state of σ_v = 1500 psi, σ_H = 3000 psi and σ_h = 500 psi.

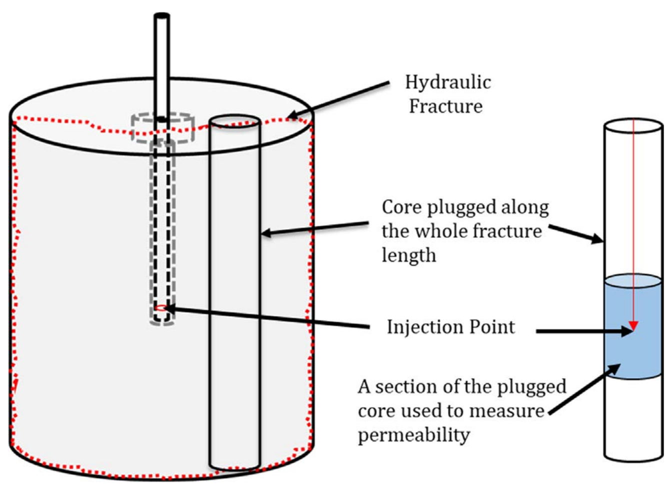

Fig. 2. Schematic showing the position of the plugged core with respect to hydraulic fracture and well bore. A section of the core (highlighted by blue color) was used to measure permeability. The section was selected in such a way that the injection point is at its centre. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article).

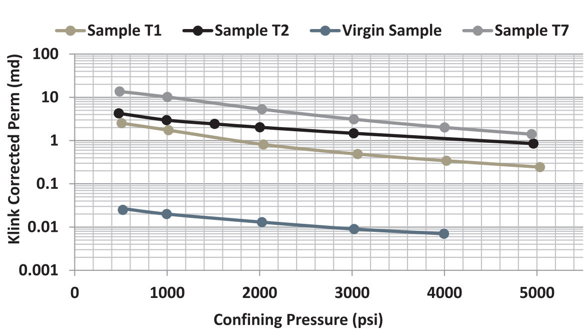

Fig. 3. Klinkenberg corrected permeability plotted as a function of confining pressure for virgin and fractured Tennessee sandstone samples. The permeability was measured using AP608™.

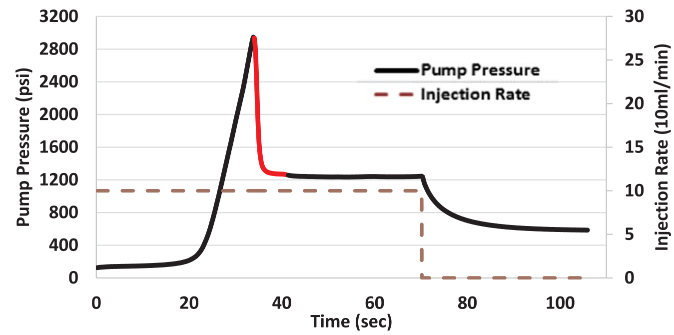

Fig. 4. A typical injection pressure curve recorded during triaxial hydraulic fracturing of Tennessee sandstone. It is hypothesized that the drop in the injection pressure just after the breakdown (highlighted in red) is due to the injection fluid flowing inside the hydraulic fracture. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article).

understand this complex fluid flow. This technique sheds light on the fluid flow mechanism during hydraulic fracturing.

2. Experimental setup

Triaxial hydraulic fracturing experiments were performed on cylindrical rock samples of dry Tennessee sandstone which were 4 in. in diameter and 5.5 in. in length. The experimental setup has been explained in detail by Patel et al.[16] A 6.35 mm diameter hole is drilled into the centre of the cylinder to a depth of 5 mm greater than the half length of the sample. A hollow steel tubing having holes at 180° phase, at 5 mm above the bottom end, is cemented into the drilled hole. The bottom end of the tube is sealed with an epoxy. This sample preparation ascertains that the injected fluid for hydraulic fracturing will be injected into the centre of the cylindrical sample (Fig. 1).

Tennessee sandstone has a porosity of 5–6% and permeability of 0.027 md at 500 psi. The porosity and permeability measurements have been done using AP608™. The circumferential velocity analysis indicates that the sandstone has very little variation in azimuthal P-wave velocity, typically 3–4%. The Tennessee sandstone is an isotropic homogeneous tight sandstone.

A vertical stress (σ_v) of 1500 psi, a maximum horizontal stress (σ_H) of 3000 psi and a minimum horizontal stress (σ_h) of 500 psi was applied during the hydraulic fracturing experiments. Vegetable oil (viscosity μ_p = 10 cP) was used as the fracturing fluid. The hydraulic fracturing experiments were carried out on several samples but the estimation of fracture permeability using mentioned method was carried out only on three samples.

3. Fracture permeability measurement

The permeability was measured using AP608™ on 1 in. in diameter core plug extracted from the hydraulically fractured samples. The plug was cored parallel to the wellbore at an azimuth and radius to capture the hydraulic fracture (Fig. 2). The plug was cored along the entire length of the fractured sample but pulse decay permeability was measured only on a section of the plug. Fig. 3 shows the Klinkenberg permeability as a function of confining pressure of virgin and fractured samples. The permeability of fractured samples is two to three orders greater than the virgin samples. Since the matrix permeability is significantly low, it is reasonable to assume that in the measured fracture permeability there is insignificant contribution of matrix permeability.

4. Methodology to estimate fracture permeability

Fig. 4 shows a typical pressure curve recorded during triaxial hydraulic fracturing of Tennessee sandstone. In the pressure curve, we observe a sharp decrease in pump pressure (injection pressure) just