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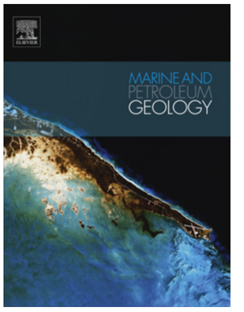

Comment on Davies et al 2012 - Hydraulic Fractures: How far can they go?

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Comment on Davies et al 2012 - Hydraulic Fractures: How far can they go?

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In the paper "Hydraulic Fractures: How far can they go?" Davies et al (2012) make an important contribution to addressing the problem of hydraulic fracture propagation distance. They analyze the mass of published data on both natural and induced fractures and demonstrate that the probability of **induced** fractures growing more than 350 meters vertically is < 1%. The purpose of this comment is to discuss an additional layer of complexity of hydraulic fracture fluid movement revealed by a new passive seismic imaging method. The additional complexity is interaction between the hydraulic fracture treatment and the preexisting natural fracture system.

Davies et al (2012) recognize that natural fracture systems can extend vertically and laterally for distances over 1 km. However, at the time of their writing they were unaware of a new method of surface-based microseismic imaging that detects subtle seismic activation of natural fractures during hydraulic fracture treatments. The method, Tomographic Fracture Imaging™ (TFI™), is described in Geiser et al (2012). TFI directly images both artificial hydrofractures and seismically active natural fractures as complex surfaces and networks. It is a very sensitive direct imaging method, not a method of connecting or interpolating microearthquake hypocenters. TFI™ detects microseismic activity that is missed by conventional microearthquake-based methods.

Natural fracture systems consist of joints (natural extensional fractures) and faults (natural shear fractures). Natural fractures may become seismically active during a fracture treatment through at least two and perhaps more mechanisms. The first mechanism is fluid pressure increase in the fracture via a direct fluid connection with the treatment well. By "direct fluid connection" we mean that a fluid pressure pulse can be transmitted either through the inter-connected pore system of the rock, through connected fractures, or both. Note that a fluid pressure pulse can be transmitted with or without significant fluid flow. By "significant fluid flow" we mean a change of the fluid composition in the affected natural fracture. The second mechanism is changes in the resolved shear stress on, or the fluid pressure within, a natural fracture due to inflation. Poroelasticity couples stress in the solid skeleton of the rock to the in-situ fluids so that stress changes can affect the fluid pressure in a natural fracture without fluid flow. "Inflation" is the elastic deformation of the rock volume around the treatment well due to introduction of the frac fluid. Such inflation is routinely observed during tiltmeter studies of hydraulic fracture treatments. The routine observation of surface deformation with tiltmeters demonstrates that such elastic deformations propagate over 1 km vertically.

As yet we have no a priori method for distinguishing the two mechanisms using only TFI™. However, in two of the 15 TFI™ studies completed to date there was independent evidence to test the two mechanisms. In both case fluid and fluid pressure communication was either confirmed (see subsequent discussion on the Mallory 145 Multi-Well Project) or was supported because the rate of fracture propagation was on the order of 20 m/sec (Geiser et al, 2006) as opposed to the 1000's of m/sec if activated by stress waves.

The earth's brittle crust is a pervasively fractured, self-organized critical system (e.g. Leary, 1997) in a state of frictional equilibrium because of pervasive fracturing (Zoback, 2007). Consequently, fluid pressure increase in a fracture under resolved shear stress reduces frictional forces and allows slip, which generates microseismic activity. Hubbert and Rubey (1959) show that slip on a fracture requires only that the fluid pressure in the fracture changes, not that any injected fluid reach the stimulated feature. The Hubbert and Rubey (1958) hypothesis was confirmed by Raleigh et al (1976). Ziv and Rubin (2000) show that stress or pressure changes of <0.01 atmosphere can stimulate seismicity. Consequently, seismic activation of a fracture can occur far from a well. Recent work by others (e.g. Zoback et al, 2012) presents direct evidence that hydraulic fracture treatments can induce shear on preexisting natural fractures by injection of fluid or transmission of fluid pressure into the fractures.

Seismic activation of natural fractures during hydraulic fracturing is important because an extensive body of literature accumulated over the last 17 years shows that hydraulic transmissivity of natural fractures correlates positively with resolved shear stress (e.g. Barton et al, 1995; Heffer et al, 1995; Tamagawa and Pollard, 2008; Hennings et al, 2012; Heffer, *in press*). Fractures under high resolved shear stress are more easily perturbed than fractures under lower resolved shear stress. Consequently, imaging seismically active fractures reveals at least part of the potentially transmissive natural fracture network. Note that an absence of seismic activity does not necessarily indicate the absence of transmissive zones because very weak, highly transmissive features (e.g breccia zones) may not generate observable seismic activity due to fluid flow or pressure changes.

We routinely monitor hydraulic fracture treatments using Tomographic Fracture Imaging™. The resulting images show induced hydraulic fractures extending outward from the wellbore and seismic activation of the natural fracture network over horizontal distances exceeding 1 km and vertical distances up to nearly 1 km. Davies et al (2012) cite measurements of vertical natural fracture networks offshore Namibia that exceed 1 km. Induced fractures could intersect natural fracture networks with similar dimensions. However, Fisher and Warpinski (2011) point out that the earth's stress field and rock mechanical properties create what is effectively a seal for vertical cracks at about 700 meters below the surface. Thus upward propagating fractures are stopped well before the approximately 300 meter maximum depth of potable ground water aquifers.

In most cases no corroborating data is available to demonstrate whether seismic activation of natural fractures is by transmission of a fluid pressure pulse through a connected system of fractures (with or without significant fluid flow), by elastic deformation, or both. In this discussion we focus on one well-documented study of a roughly 500 meter thick sequence of stacked reservoirs that were stimulated with four vertically stacked horizontal wells – the Mallory 145 Multi-Well Project (MAL145). This study demonstrates direct fluid connection during hydraulic fracturing over roughly 500 meters vertically (the separation of the uppermost and lowermost laterals) and over a kilometer laterally. In this case the frac fluid was N_2 gas, which is highly mobile. Some aspects of this study are described in Geiser et al (2012), Moos et al (2011), Franquet et al (2011), and Mulkern et al (2010). Here we provide additional description focused on the potential extent of frac fluid movement in natural fracture systems.

Figure 5 of Geiser et al (2012) shows a TFI of a dense fracture network activated by hydraulic fracture stimulation of the four vertically stacked laterals. Figure 6 of Geiser et al (2012) shows the network for a single well with the chemical tracer distribution for that well. This network extends to the well located approximately 1.5 kms southwest of the treatment wells. N_2 was detected at that well within an hour of frac initiation at one of the horizons thus confirming lateral communication through the natural fracture system. Chemical tracer data provided further evidence of fluid communication over these distances (Mulkern et al, 2010; Geiser et al, 2012). The sealing unit was a series of shales interbedded with tight sandstones. Borehole imaging and remote sensing data (unpublished) confirmed that the ancient natural fractures present at the surface have similar orientations to those in the reservoir. However, all seismic activity clearly terminated at the reservoir seal, which was about 725 meters below the surface (see Figure 8 of Geiser et al, 2012). Extensive chemical data on the reservoir gases (unpublished) shows that gas compositions within this compartment are similar, indicating natural connectivity within the compartment.

The MAL145 reservoirs may not be representative of all unconventional reservoirs. Although the pays are all unconventional gas reservoirs (tight sand, shale, and siltstone) the reservoir is a known fractured reservoir and some wells produce naturally – without stimulation. Correlation of open-hole production logs with borehole images and Stonely wave data shows that natural fractures in the study volume produced gas prior to stimulation and were transmissive. Seismic activation of fractures occurred only within the naturally connected reservoir compartment. Although in general the microseismic activity imaged by TFI does not prove direct fluid communication, chemical tracer and other data at MAL145 do prove fluid communication. Because of the observed transmissivity of natural fractures in the reservoir compartment, we find it likely that the N_2 was transmitted throughout the 0.9 km vertical interval that showed subtle seismic activity.

In conclusion, although we agree with Davies et al (2012) regarding propagation of artificial hydraulic fractures, hydraulic fracture fluid and fluid pressure pulses can move greater distances in preexisting natural fracture systems. Fluid pressure pulses can be transmitted without significant flow, i.e. without changing the original fluid composition in the fracture network.

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