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Discussion

Reply: Davies et al. (2012), Hydraulic fractures: How far can they go?

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1. Introduction

Davies et al. (2012) measured the heights of stimulated and natural hydraulic fractures caused by high fluid pressure from eight sedimentary successions from around the world. They found the tallest natural hydraulic fractures to be ~1133 m in height and the tallest upward propagating stimulated hydraulic fractures, generated by fracking operations for gas and oil exploitation to be 588 m in height. This provided a rationale for an initial, safe separation distance of 600 m between aquifers and the deeper shale gas and oil reservoirs where hydraulic fractures are being stimulated. Three months after the paper went online, Geiser et al. (2012) published a new method, tomographic fracture imaging, which potentially detects the movement of a fluid pressure pulse in pre-existing natural fracture systems located close to where stimulated hydraulic fractures are forming. These fracture systems are not necessarily natural hydraulic fractures, but could be joints and faults formed due to folding or faulting. They found the maximum vertical extent of these to be ~1000 m. Here we respond to the comment made by Lacazette and Geiser (2013) and consider the implications of the new findings of Geiser et al. (2012) for the conclusions we made (Davies et al., 2012).

2. The hydraulic fracturing controversy

Hydraulic fractures are stimulated to increase the rate of fluid flow from low permeability oil and gas reservoirs (e.g. shale). The aim of Davies et al. (2012) was to test the hypothesis that hydraulic fracturing has caused methane contamination of drinking water in the USA and to provide an evidence base for the safe vertical separation distance between shale reservoirs and aquifers. The contamination hypothesis was explicit in the title of the Osborn et al. (2011) paper 'Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing' and popularised by the 2010 film '*Gaslands*'.

The approach adopted by Davies et al. (2012) was entirely empirical and based upon measuring the heights of natural and stimulated hydraulic fractures. We did not consider the vertical extent of fractures unrelated to pore pressure caused by tectonic stresses exceeding the tensile strength of the rock. Also for the stimulated hydraulic fractures we relied upon the microseismicity measurements of Fisher and Warpinski (2011). From this database of thousands of the tallest hydraulic fracture systems, we derived probability of exceedance plots for hydraulic fracture heights. These provide a range of probabilities of natural and stimulated hydraulic fractures extending vertically beyond specific distances. The results indicated that no stimulated hydraulic fractures heights measured using microseismicity and published by Fisher and Warpinski (2011) propagated upwards past 588 m in height and the chances of an artificially stimulated hydraulic fracture propagating vertically past 350 m was only 1%.

3. Is a 600 m vertical separation distance safe?

Davies et al. (2012) was purely statistical and therefore blind to factors such as local geology and operational variables such as the volume of fracturing fluid used which would need to be considered for safe operations at a specific site. If the geology of a region where

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hydraulic fracturing is carried out is characterised by evidence for vertically extensive fluid flow (e.g. mud volcanoes which can extend vertically for >>1 km), then this introduces a significant risk that there are open pathways for fluid migration. But there may also be natural barriers to fracture propagation, known as ‘frack barriers’, which could limit the extent of fractures so that the tallest fractures are <<600 m.

Lacazette and Geiser (2013) in their comment propose that fluid pressure pulses triggered by hydraulic fracturing move vertical distances of ~1 km through pre-existing natural fracture systems, hundreds of metres further than the maximum propagation distance for stimulated hydraulic fractures (Fisher and Warpinksi, 2011; Davies et al., 2012). This is detected using a new tomographic fracture imaging method (Geiser et al., 2012). The work of Davies et al. (2012) remains valid as a statistical analysis of stimulated hydraulic fracture height measurements derived using microseismicity. But this avoids the important question; does the new tomographic fracture imaging method reveal pre-existing fractures, not necessarily generated by natural hydraulic fracturing, that allow for a far more vertically extensive transmission of fracking or pore fluid? If so what are the implications?

The new method is a passive seismic monitoring technique which may detect energy released as a result of the transmission of fluid pressure pulses. The method assumes that energy emission is linearly related to the sum of the area of failure over time and that regions of highest crack density have the highest semblance value. They also state that they use a summation method to capture a greater fraction of the acoustic energy generated by fracturing, allowing imaging of very weak activity. In the form the method is presented by Geiser et al. (2012), there are three shortcomings. Our first concern is that perhaps because of proprietorial reasons, the exact workflow they use to detect this pressure pulse is not described in detail.

Secondly, they are unclear on the exact physical process that is potentially being detecting. Geiser et al. (2012) hypothesize that it may be some sort of the Biot ‘slow wave’ (Biot, 1962). Lacazette and Geiser (2013) propose that two processes are potentially operating, the transmission of a fluid pressure pulse in the fracture due to its direct connection with fracking, and coupling of stress in the rock matrix by in-situ fluid. Thirdly, although they document some validation of their method (e.g. using boreholes which detect

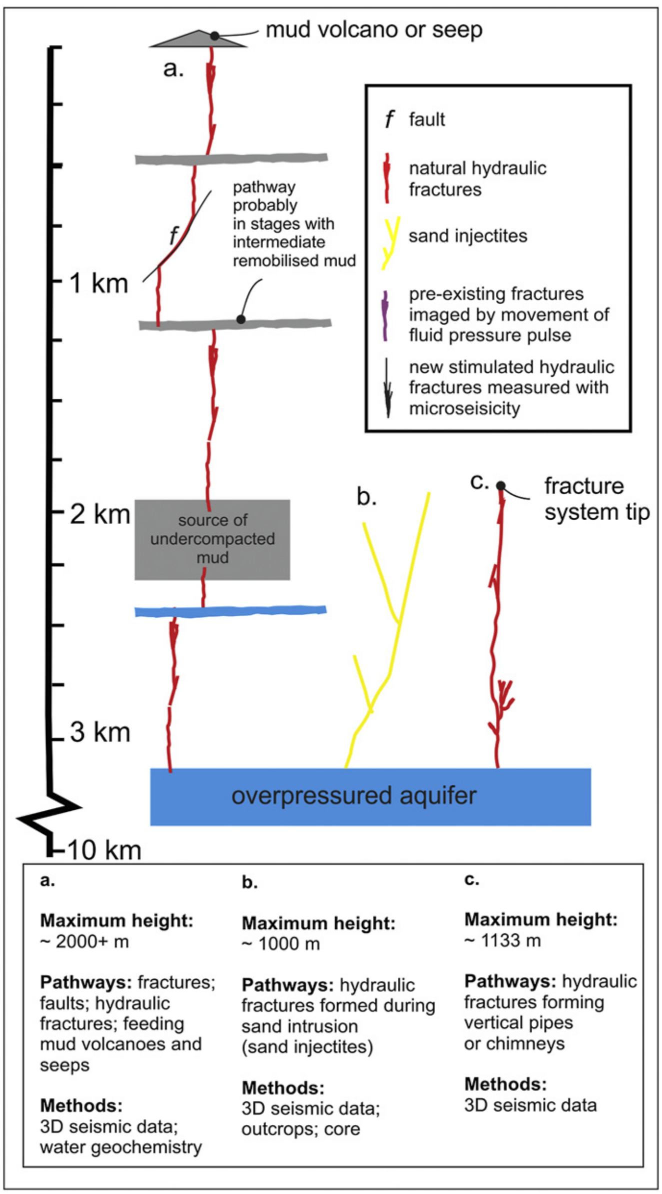

Figure 1. Approximate maximum vertical extent of fluid transmission in natural fracture systems. (a) Fractures, faults and hydraulic fractures normally located within the crest of anticlines can allow fluid flow in mud volcano systems (Kopf et al., 2003; Davies and Stewart, 2005; Stewart and Davies, 2006). Fluid flow may be in stages to intermediate fluid reservoirs and the fluid has been traced to reservoirs >2 km in depth (Kopf et al., 2003); (b) injectites are thought to extend a maximum of up to ~1 km, form due to hydraulic fracturing and the remobilisation of sand, driven by overpressure (Hurst et al., 2011); (c) chimneys or pipes are probably clusters of hydraulic fractures imaged with seismic reflection data (Løseth et al., 2001; Hustoft et al., 2010; Moss and Cartwright, 2010).

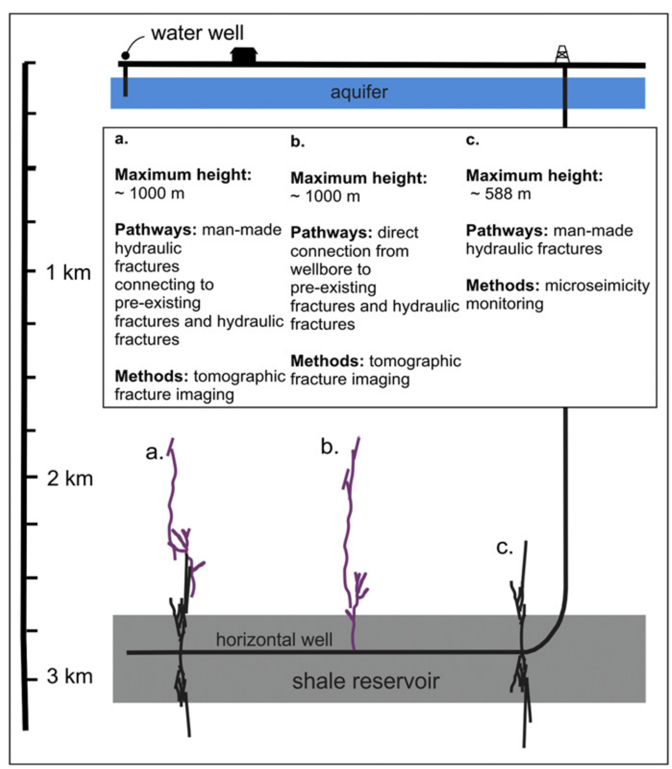

Figure 2. Potential maximum vertical extent of fluid transmission and fluid pressure pulse transmission related to fracking operations. (a) and (b) fluid pressure pulses may be transmitted through pre-existing fracture systems of 1 km in vertical extent (Geiser et al., 2012); (c) stimulated hydraulic fractures may extend for ~ 600 m vertically (Fisher and Warpinski, 2011; Davies et al., 2012). The vertical scale is indicative as the depth of the shale reservoir varies.

fractures located in similar positions to those imaged), more validations need to be published before the method is fully substantiated.

Despite these issues, the method and results are potentially a very significant addition to existing seismic approaches used to monitor fracking operations. If the method performs well it will extend the ability of passive seismic monitoring to map fractures activated over time-scales longer than the nucleation time of stimulated hydraulic fractures. It may dramatically improve our understanding of the extent of pre-existing fracture systems and ultimately verify whether fractures allow fluid transmission to shallower levels than previously thought possible, over human time-scales.

4. Implications for the protection of water supplies

It has long been know that fracture systems of 1000 m extent occur in sedimentary rocks (Løseth et al., 2001) and Davies et al. (2012) showed that three-dimensional seismic data can image natural hydraulic fractures that extend this far. If we assume fractures (hydraulic or otherwise) are also being imaged by the tomographic fracture imaging approach then the key question is whether they remain open after the fracking operations to enable the ascent of fluid. Confining stresses would cause fractures to close-up when pumping stops and the pressure in the fluid drops so a system of open fractures to shallow levels is difficult conceive. It would require there to be sedimentary strata at the level of the reservoir that are permeable and natural ovepressure that keeps the conduits open and active. But we cannot be certain that there are no permeable routes through pre-existing fracture systems. It is important to state that after thousands of fracking operations, there are no proven examples of contamination of drinking water aquifers due to hydraulic fracturing. But we take the opportunity to incorporate the new measurements of Geiser et al. (2012) in a new summary diagram of the heights of fractures potentially stimulated by the fluid injection during hydraulic fracturing operations (Fig. 1). We also provide the maximum heights for a range of natural vertical fluid flow pathways, which include hydraulic fractures and other routes, such as joints and faults (Fig. 2).

The new work of Geiser et al. (2012) highlighted in the Lacazette and Geiser (2013) comment shows that consideration of local geology and specifically the existance of vertically extensive fracture systems are important parts of risk assessments prior to fracking operations. In this reply we have taken the opportunity to include the potential existance of other types of vertically extensive fracture system evidenced by active mud volanoes and seeps which were not described in our earlier paper (Davies et al., 2012). Such phenomena are easily recognised and their locations are well known so they can readily be avoided.

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