Hydraulic Fractures: How Far Can They Go?

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ABSTRACT

The maximum reported height of an upward propagating hydraulic fracture from several thousand fracturing operations in the Marcellus, Barnett, Woodford and Eagleford shale (USA) is ~ 588 m. Of the 1170 natural hydraulic fracture networks offshore of West Africa and mid-Norway it is ~ 1106 m. Based on these empirical data, the probability of a stimulated and natural hydraulic fracture extending vertically > 500 m is ~ 1% and ~ 15% respectively. The datasets and statistics should help inform decisions on the safe vertical separation between hydraulic fracturing and rock strata not intended for intersection.

INTRODUCTION

Hydraulic fractures propagate when fluid pressure exceeds the least principal stress and the tensile strength of the host sediment (Hubbert & Willis 1957). They continue to propagate until the stress-intensity at the fracture tip is lower than the critical stress-intensity of the rock being fractured. These conditions can occur naturally (e.g. Cosgrove 1995) but they can also be stimulated to recover oil and gas (Simonson *et al.* 1978), or during injection of water into geothermal boreholes (e.g. Legarth *et al.* 2005; Julian *et al.* 2010) and unintentionally as the result of subsurface blowouts (e.g. Tingay *et al*. 2005).

Natural examples are commonly described in outcrops at centimetre to metre scale (e.g. Cosgrove 1995) – Fig. 1ab – the vertically most extensive are ~ 50 m in height (e.g. Engelder & Lash 2008). Sand filled fractures (injectites) have been documented to extend further (Hurst *et al.* 2011). But three-dimensional (3D) seismic data now show that natural hydraulic fractures can extend vertically for much greater distances than this (see Løseth *et al*. 2001; Zuhlsdorff & Spieß 2004; Cartwright *et al*. 2007; Davies & Clarke 2010). Hydraulic fracturing as a reservoir stimulation technique for improved hydrocarbon production dates back to the late 1940s (Montgomery and Smith 2010). Measurements of the microseismicity they cause (e.g. Maxwell *et al*. 2002) have shown that they can extend for several hundred metres upwards and downwards from the wellbore (Fisher & Warpinski 2011). Multiple stages of hydraulic fracture stimulation on multiple wells are routine for the recovery of oil and gas from low permeability sedimentary reservoir in several shale gas provinces in the USA (e.g. King 2010). Shale gas exploration is starting in many other countries with sediments from Neogene to Cambrian age being potential future drilling targets. Therefore constraining the maximum vertical extent of hydraulic fractures in sedimentary rocks is critically important, as it will help avoid the unintentional intersection of shallower rock strata (Fig. 2).

Mathematical methods for estimating hydraulic fracturing height are simplistic (Fisher & Warpinski 2011) and it is generally accepted that we cannot yet accurately predict fracture propagation behaviour in detail, so to date much of what we know of how fractures will behave *in situ* conditions comes from operational experience (King *et al.* 2008). Future shale gas targets could be in sediment of Neogene to Cambrian age, in a variety of different stress regimes and in rocks with varied mechanical properties. Therefore at this stage our approach is to include a wide range of examples of hydraulic fractures, with different trigger mechanisms, different geometries and from different geological settings to provide a holistic analysis.

Although hydraulic fractures are 3D, here we compile new and existing data on the extents of only the vertical component of both natural and stimulated hydraulic fracture systems hosted in sediment from Neogene to Devonian in age from five different locations (Fig. 3a). We briefly report on key statistics, compare them and consider what controls the extent of upward fracture propagation.

Hydraulic fracturing

Hydraulic fractures can propagate naturally, for example in the formation of injectites (e.g. Hurst *et al.* 2011) or can cluster forming vertical networks commonly termed chimneys, pipes or blowout pipes (e.g. Cartwright *et al.* 2007). They are thought to be triggered as a result of critical pressurisation of pore fluid (Osborne & Swarbrick 1997). There exact origin is not certain, but their most likely cause is hydraulic fracturing due to critical pressurisation (Zuhlsdorff & Spieß 2004; Cartwright *et al*. 2007; Davies & Clarke 2010). This may be followed by stoping, fluid-driven erosion, collapse of surrounding strata (Cartwright *et al.* 2007). Gases that have come out of solution during fluid advection may also have a contributory role in their development (Brown, 1990; Cartwright *et al.* 2007). The earth's tallest examples form pipe-like clusters that are recognised on seismic reflection data on the basis of vertically aligned discontinuities in otherwise continuous reflections (Fig. 3b and Cartwright *et al.* 2007).

Stimulated hydraulic fractures are created to significantly increase the rate of production of oil and gas from fine-grained, low permeability sedimentary rocks such as shale. Commonly a vertical well is deviated so that it is drilled approximately horizontally through the shale reservoir (Fig. 2). The production casing is perforated and hydraulic fractures stimulated by injecting saline water with chemical additives. 'Proppant' (for example sand) is used to keep the fractures open (see King 2010). Hydraulic fracture stimulation from a horizontal borehole is usually carried out in multiple stages with known volumes and compositions of fluid (e.g. Bell & Brannon 2011). Rather than pipes forming clustering commonly occurs along planes, which theoretically are orthogonal to the least principle stress direction. So there are fundamental differences in the geometry of the fracture systems, the reasons for which are not yet understood.

Hydraulic fractures can be also be stimulated unintentionally for example as an underground blowout (e.g. Tingay 2003) and they can unintentionally be caused by the injection of waste water at high enough rates to generate pore pressures which exceed the pressure required for hydraulic fracturing (e.g. Løseth *et al.* 2011).

DATASETS

Hundreds of pipes have recently been identified on 3D seismic reflection surveys in continental margin settings (Davies and Clarke 2010; Hustoft *et al.* 2010; Moss & Cartwright 2010). We compile new data based upon these surveys on the vertical extents of 1170 pipes (e.g. Fig. 3ab). Pipe heights were measured by recording their bases and tops in two-way-travel time and converting these to heights using estimated seismic velocities for the host successions (Davies & Clarke, 2010; Moss & Cartwright, 2010; Hustoft *et al.* 2010). Errors are related to the seismic resolution and the estimation of the velocity of the sediment and are probably < 20%. Because of the limits of vertical seismic resolution the numbers of hydraulic fractures that have vertical extents of less than 100 m are probably underestimated. We have not included in this study the vertical extents of injectites because their mode for formation with the entrainment of sediment is quite different (e.g. Hurst *et al.* 2011).

The vertical and horizontal extents of stimulated hydraulic fractures used to recover hydrocarbons can be estimated using the energy released by the hydraulic fracturing which is recorded as microseismicity in a nearby borehole (e.g. Maxwell *et al*. 2002). We used a compilation of microseismic events (Fisher & Warpinski, 2011). They presented measurements of the fracture tops and bottoms for ‘thousands’ of mapped fracture treatments performed in the Barnett, Woodford, Marcellus and Eagle Ford shale gas formations recorded from early 2001 to the end of 2010 (their figures 2-6 respectively). Because we did not have access to the primary database our measurements were made by digitising their published graphs (Fig. 3c). This will have introduced errors but again this will be mainly with the shorter hydraulic fractures (with vertical extents < 100 m) therefore the numbers of these are also underestimated. This does not change our main conclusions as it is the taller fractures that we focus upon. There are also errors associated with the microseismic method, mainly associated with estimating the velocity of the rock between the hydraulic fracture and the monitoring well (e.g. Maxwell *et al*. 2002).

There is significant uncertainty in the depth of the initiation of fracture systems caused by underground well blowouts, hence we do not draw on this source of data in this paper. But the depth of the fracture initiation is well constrained where waste water is being injected, so here we use a recently reported example from the Tordis Field, offshore Norway where the fractures eventually intersected the seabed (Løseth *et al.* 2011). This example provides some additional context for the natural and stimulated datasets described.

RESULTS

Natural hydraulic fractures

Offshore of Mauritania 368 vertical pipes were identified over an area of 1880 km^2 (Davies & Clarke 2010 - Fig. 3ab) and it was possible to measure the vertical extent of 360 of these. They are hosted on a passive continental margin, probably within fine-grained turbidites and foram-nannofossil hemipelagites (Henrich *et al.* 2010). A graph of frequency against vertical extent shows the most common vertical extent is between ~ 200 m and ~ 300 m. The tallest conduit is ~ 507 m (Fig. 4a). The average vertical extent is 247 m.

Offshore of Namibia, we measured 366 vertical chimneys in a succession composed of fine grained claystones of Miocene to Recent age (Moss & Cartwright 2010. The average vertical extent is 360 m. The maximum vertical extent is ~ 1106 m (Fig. 4a). Vertical chimneys also form offshore mid Norway within the Oligocene to Recent fine grained mudstone and siliceous mudstones of the Brygge, Kai and Naust Formations (Hustoft *et al.* 2010). 66% of these terminate at the seabed. Of the 446 pipes the average vertical extent is 338 m. The maximum vertical extent is ~ 882 m (Fig. 4a). Graphs of hydraulic fracture height against the probability of non-exceedance of this height for each dataset show the probability of a natural hydraulic fracture exceeding a range of vertical extents (Fig. 4b). Based upon these data the probability of a natural hydraulic fracture extending vertically > 500 m is ~ 15% (Fig. 6ab)

Stimulated hydraulic fractures

Our compilation of data from the USA shales (Fisher & Warpinski, 2011 – Fig. 3c) shows that generally the Marcellus is the shallowest reservoir, then the Barnett, Woodford and the Eagleford. The maximum upward propagation of fractures initiated in these reservoirs is 536 m, 588 m, 288 m and 556 m respectively but in each case the vast majority of hydraulic fractures propagate much shorter distances (Fig. 5ab). For upward propagating hydraulic fractures, the trend is that shallower strata generally host taller fractures (Fig. 5abcd). Therefore the probability of an upward propagating fracture exceeding a height of 200 m, for example, is highest for those initiated in the Marcellus then the Barnett, Woodford and Eagleford shale reservoirs. There is no such relationship for downward propagating fractures. Based upon these data the probability that an upward propagating hydraulic fracture extends vertically > 500 m is ~ 0.8% (Fig. 6ab). We cannot accurately estimate the average vertical extent as we could not accurately measure those fractures that were < 100 m.

Unintentionally stimulated hydraulic fractures

At the Tordis Field, offshore Norway, waste water produced due to oil production was injected at ~ 900 m below the surface. This caused hydraulic fractures to propagate approximately 900 m to the seabed. Pressure profiles from the injection well show a stepped fracturing of the overburden (Løseth *et al.* 2011). The injection lasted for approximately 5.5 months, while the leakage to seafloor may have occurred for between 16 and 77 days (Løseth *et al.* 2011).

INTERPRETATION AND DISCUSSION

Vertical extent

Offshore mid-Norway there are controls on the locations of the bases of the pipes as many emanate from overpressured strata and 66% terminate at the present-day seabed (Hustoft *et* *al.* 2010) and these controls cause the peak in the frequency versus depth plot between 300-350 m (Fig. 4a). Both of these factors have an influence the shape of the probability of exceedance versus height curves (Fig. 4b). In contrast only 12 of the 360 pipes from offshore Mauritania terminate at a palaeo-seabed and a small number of pipes in the Namibe Basin do this. Despite these limitations of the datasets it is clear most of the natural hydraulic fractures reported here are 200-400 m in height and that very few natural fracture systems reported to date propagate beyond a height of 700 m. The tallest is 1106 m, which is comparable to the tallest injectites documented (Hurst *et al.* 2011). Lastly natural hydraulic fractures generally propagate upwards further than stimulated hydraulic fractures (Fig. 6ab).

The vast majority of stimulated hydraulic fractures have a very limited vertical extent of < 100 m (Figs. 3c and 5a) and the tallest is 588 m. These taller hydraulic fractures probably form by intersecting existing faults which has been recognised because the clustering and the magnitude of microseismic events changes (Warpinski & Mayerhofer, 2008).

Controls on vertical extent

The vertical extent depends on how long it is possible to continuously maintain high enough fluid pressure to keep a fracture set open and for propagation of its tip to take place. Stimulation of hydraulic fractures in shale gas reservoirs normally takes place over time periods of only 1-2 hours for a single fracturing stage. When this period has been increased, for example in the Barnett Shale, where pumping for an 11.7 hour period took place with a total volume of c. 5565 m^3, the maximum height of hydraulic fractures was only ~ 266 m (Maxwell *et al.* 2002). During pumping periods of up to 11.3 hours into the Barnett Shale the relationship between height and pumping time and volume was shown not to be strong (Shelley *et al.* 2011) and fractures stopped propagating vertically after only 1-3 hours. In the shale gas provinces local geology such as variations in lithology, provide natural barriers to propagation because they of higher confining stress or high permeability which allows the fluid to bleed off (Fisher & Warpinski, 2011). For example in the Barnett shale the Viola and Ellenberger limestones located below the Barnett Shale can limit the downward propagation of hydraulic fractures (King *et al.* 2008).

We propose that natural hydraulic fractures have greater vertical extents for a number of reasons. There is much more fluid and much longer timescales available for the fracture propagation. A volume of ~ 6 x 10^9 m^3 is reported for an aquifer in the North Sea (UK) (Heward *et al.* 2003). Although the flux of only some of the fluid from an aquifer would cause pressure to drop to hydrostatic levels and therefore only some of this fluid would have a role in pipe development, there are orders of magnitude higher volumes of fluid available than used in fracture stages in shale gas wells. Gas that comes out of solution during ascent of fluid in natural hydraulic fractures could also have a contributory role in propagation (Cartwright *et al.* 2007). Those recorded here are hosted within fine-grained, relatively homogenous successions on continental margins where there are fewer mechanical boundaries and generally low permeability strata that do not allow fluid to bleed off and therefore pressure to drop. Lastly there are significant geometrical differences between natural and stimulated hydraulic fractures and we at present do not know what influence this has on height. Despite these differences there are similar trends in the datasets. The vast majority of both natural and stimulated hydraulic fractures are < 500 m in vertical extent (Fig. 6a). This is because of variations in-situ stress, weak interfaces, material property contrasts and high permeability layers in sedimentary successions, particularly heterogeneous ones, which provide natural barriers to fracture propagation.

At the Tordis field, where the average rate of injection was 7000 m^3 a day for 5.5 months (total volume ~ 1,115,000 m^3). Fractures grew from ~ 900 m depth to the surface. But this volume of fluid is over ~ 123 times greater than typically used for fracture stages in the shale gas reservoirs and over a time period hundreds of times longer.

Løseth et al, (2011) reported that pressure profiles from the injection well show a stepwise fracturing of the overburden and that fractures actually propagated for 900 m reaching the surface (the seabed). They were also demonstrated at centimetre scale through the mine-back experiments carried out in the USA where stimulated fractures were exposed by excavating them (e.g. Cipolla *et al*. 2008). Propagation continues once the stress at the new boundary exceeds the least principal stress and the tensile strength of the host sediment and the stress-intensity at the fracture tip is lower than the critical stress-intensity of the rock being fractured. Therefore to develop the vertically most extensive fracture systems there needs to be long periods of injection of high pressure fluid (probably >> 1 day). There would be several steps in the propagation of the fracture system, breaking through permeable beds and mechanical boundaries. Mechanically homogeneous successions with low permeability will result in vertically more extensive fractures than heterogeneous formations with variable permeability and confining stress.

Implications and further work

Further research should include additional datasets from other settings to further increase confidence that exceptional propagation heights are captured. For example testing whether there are relationships between the maximum height of fractures and the type of stress regime (i.e. conducive for shear failure or tensile failure), or looking at fracture propagation from other rock types with different volumes of pumped fluids.

There are some geological scenarios where there could be connectivity of permeable reservoirs through a significant thickness of overburden. For example sand injectites can cut through ~ 1000 m of shale (e.g. Hurst *et al.* 2011) and this could, given long enough pumping time cause critical pressurisation of shallower strata and therefore shallower fractures. These types of scenario could be modelled.

Stimulated hydraulic fractures have been proposed as a mechanism for methane contamination of aquifers located 1-2 km above the level of the fracture initiation (Osborn *et al.* 2011). Because the maximum upward propagation recorded to date in the Marcellus shale is 536 m this link is unlikely (Davies, 2011; Saba & Orzechowsk 2011; Schon, 2011).

CONCLUSIONS

Natural hydraulic fracture networks have the potential to propagate upwards further there stimulated ones. Taller stimulated hydraulic fractures tend to form in shallower strata and the maximum upward propagation recorded to date is ~ 588 m in the Barnett shale in the USA. Based upon the data presented here the probability that a stimulated hydraulic fracture extends vertically beyond > 500 m is < 1%. This compilation should be added to with new empirical data in order to best inform industry and academic geoscientists and engineers, regulators, non government organisations and publics for safe shale gas operations.

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FIGURES

Figure 1 (a) Examples of natural hydraulic fractures in shale (b) close-up of a natural hydraulic fracture filled with shale clasts (both (a) and (b) from onshore Azerbaijan).

Figure 2 Schematic diagram showing stimulated hydraulic fractures within a shale gas reservoir, natural hydraulic fractures initiated at a naturally overpressured reservoir, the vertical extent of hydraulic fractures reported here and the separation between shale gas reservoir and shallower aquifer.

Figure 3 (a) Map of the globe showing location of the five datasets. (b) Seismic line from offshore Mauritania showing a representative vertical pipe imaged on 3D seismic reflection data. (c) Graph of stimulated hydraulic fractures in the Barnett Shale (after Fisher & Warpinski, 2011) showing how the vertical extents of fractures were measured. All depths are in true vertical depth (TVD). The Black dashed line - depth of the stimulation of the hydraulic fractures. Coloured spikes – separate hydraulic fractures propagating upwards and downwards from depth of stimulation.

Figure 4 Graph of frequency against vertical extent for natural hydraulic fractures (pipes) identified on 3D seismic data from (a) offshore Mauritania, (b) Namibe Basin (c) mid Norway.

Figure 5 Graphs of frequency against hydraulic fracture height for (a) upward and (b) downward propagating fractures in the Marcellus, Barnett, Woodford and Eagleford shales. Graphs of probability of exceedance against height of (c) upward propagating fractures and (d) downward propagating fractures.

Figure 6 (a) Graph of frequency against fracture height for all stimulated and natural hydraulic fractures. (b) Graph of probability of non-exceedance against fracture height for stimulated and natural hydraulic fractures.

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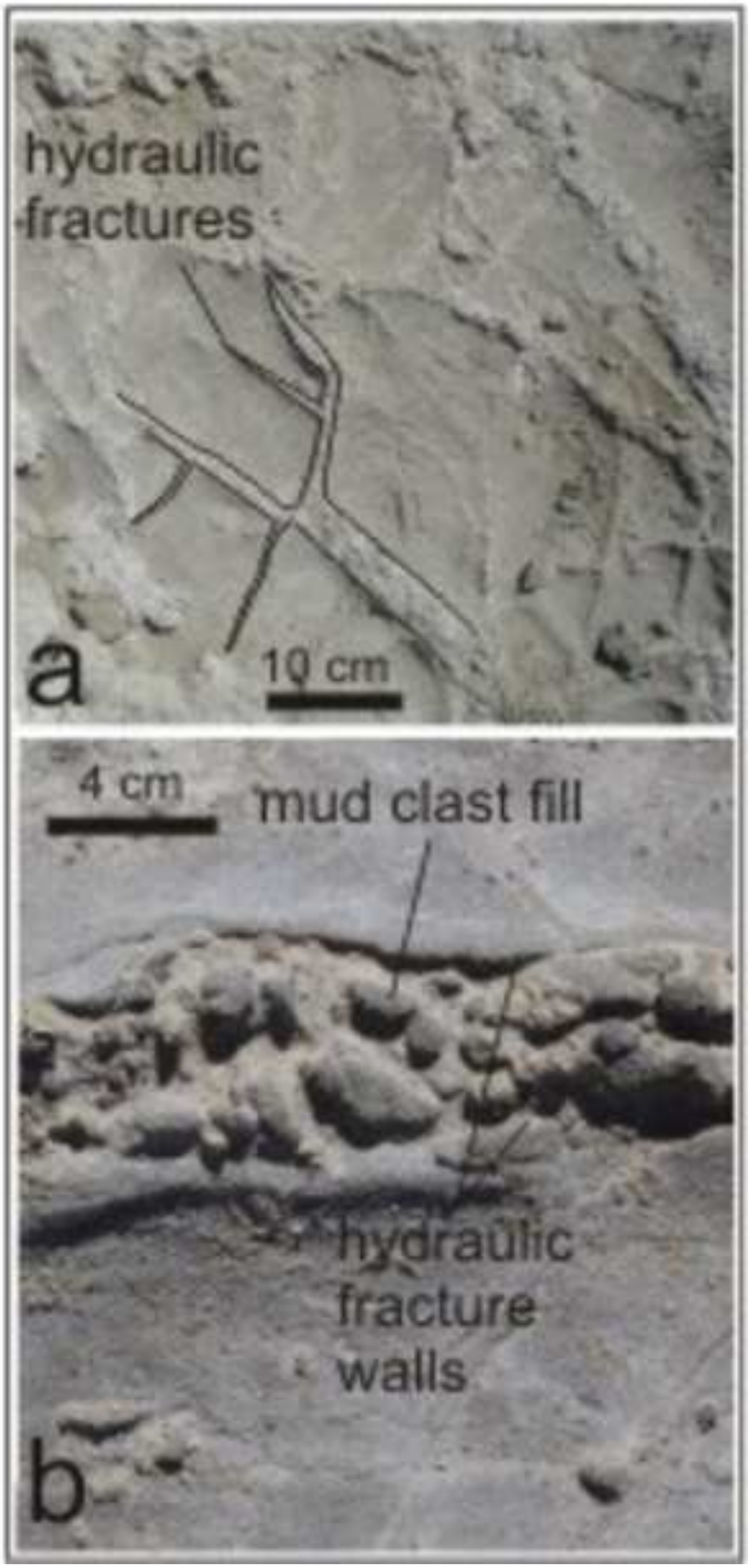

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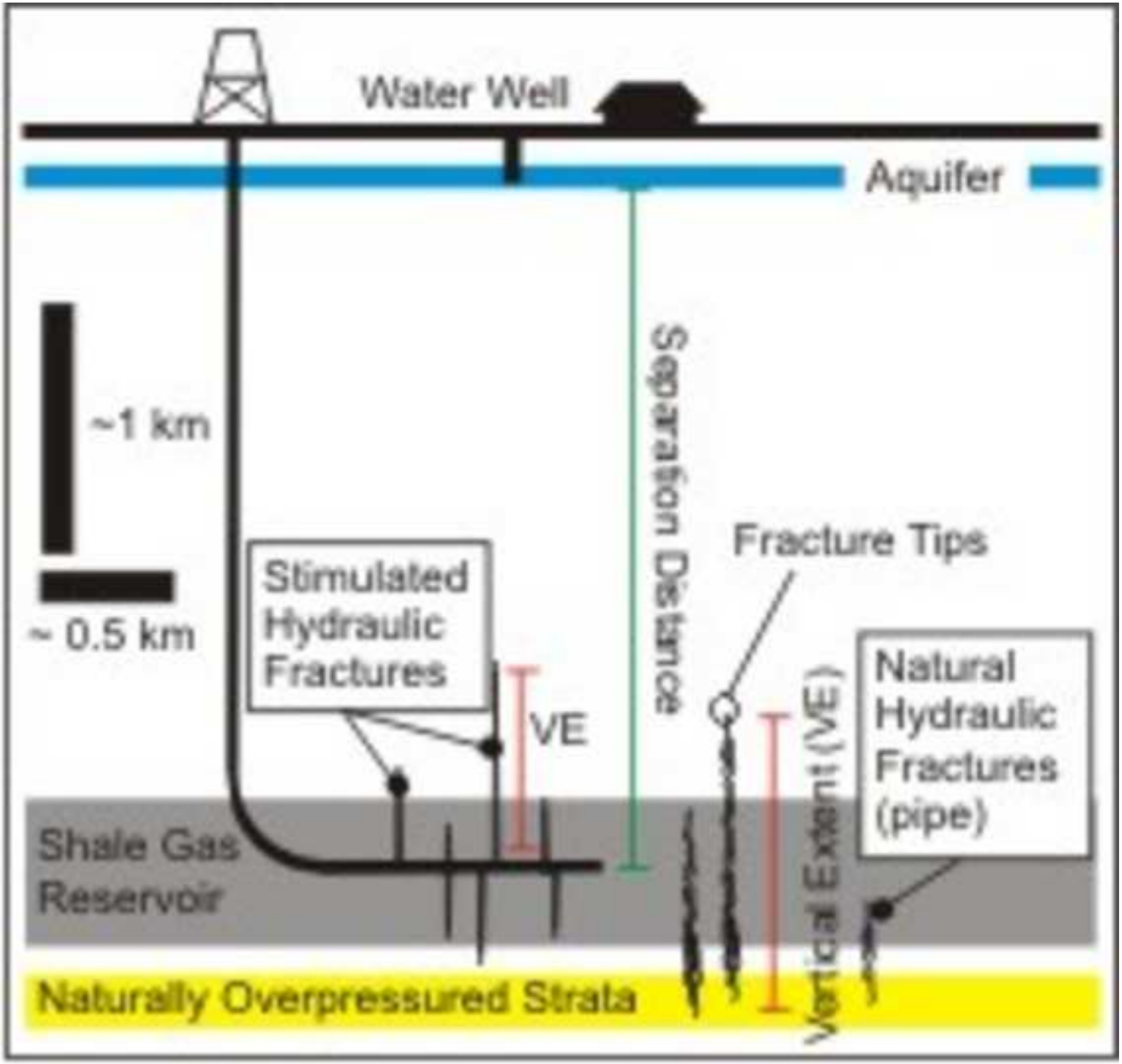

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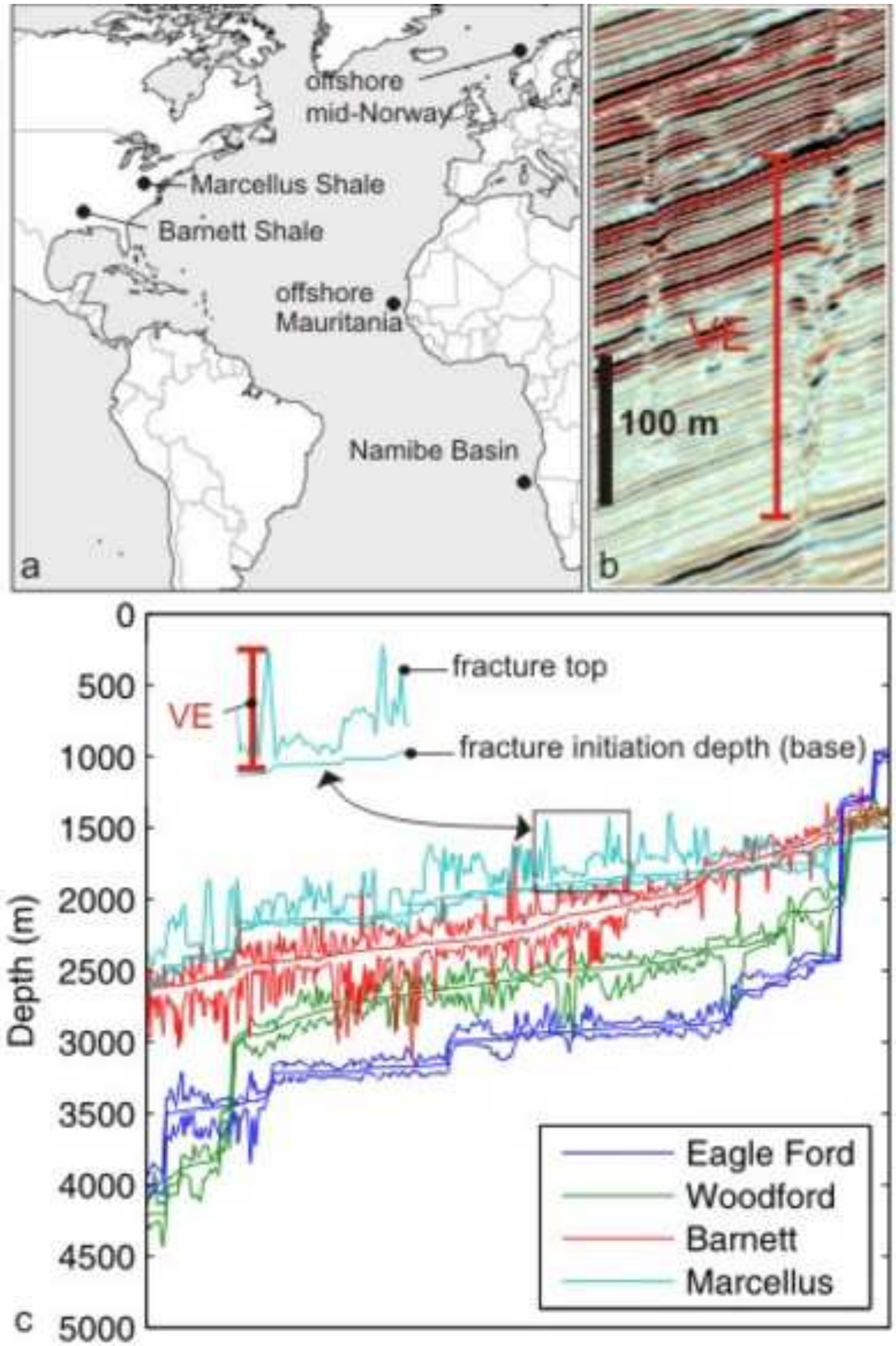

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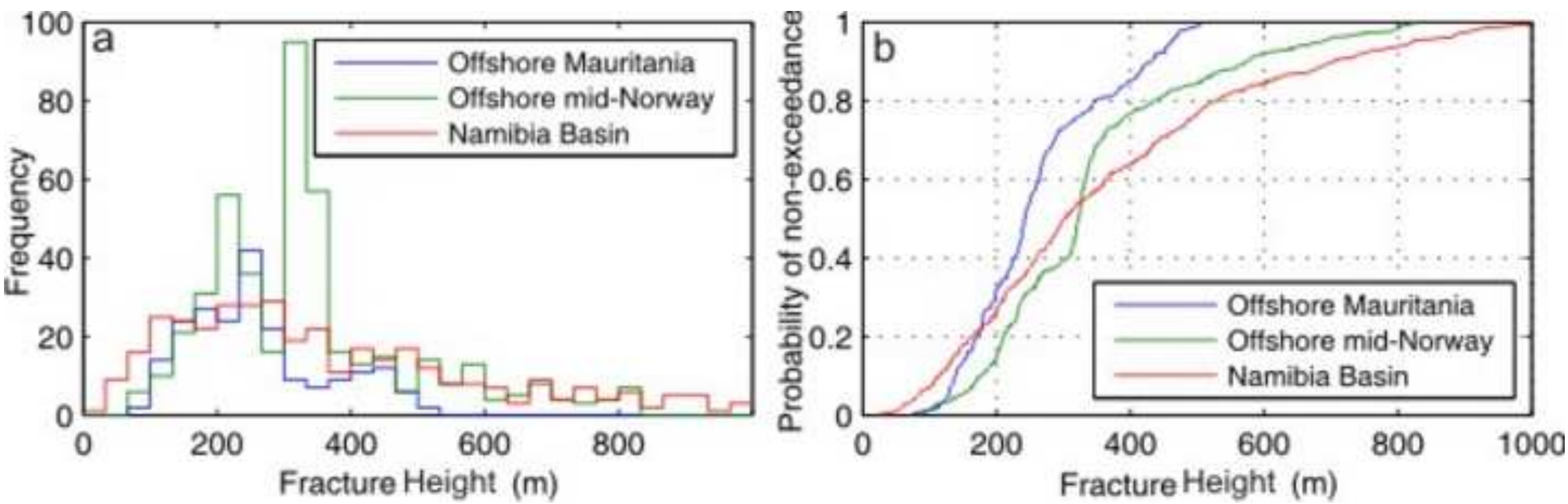

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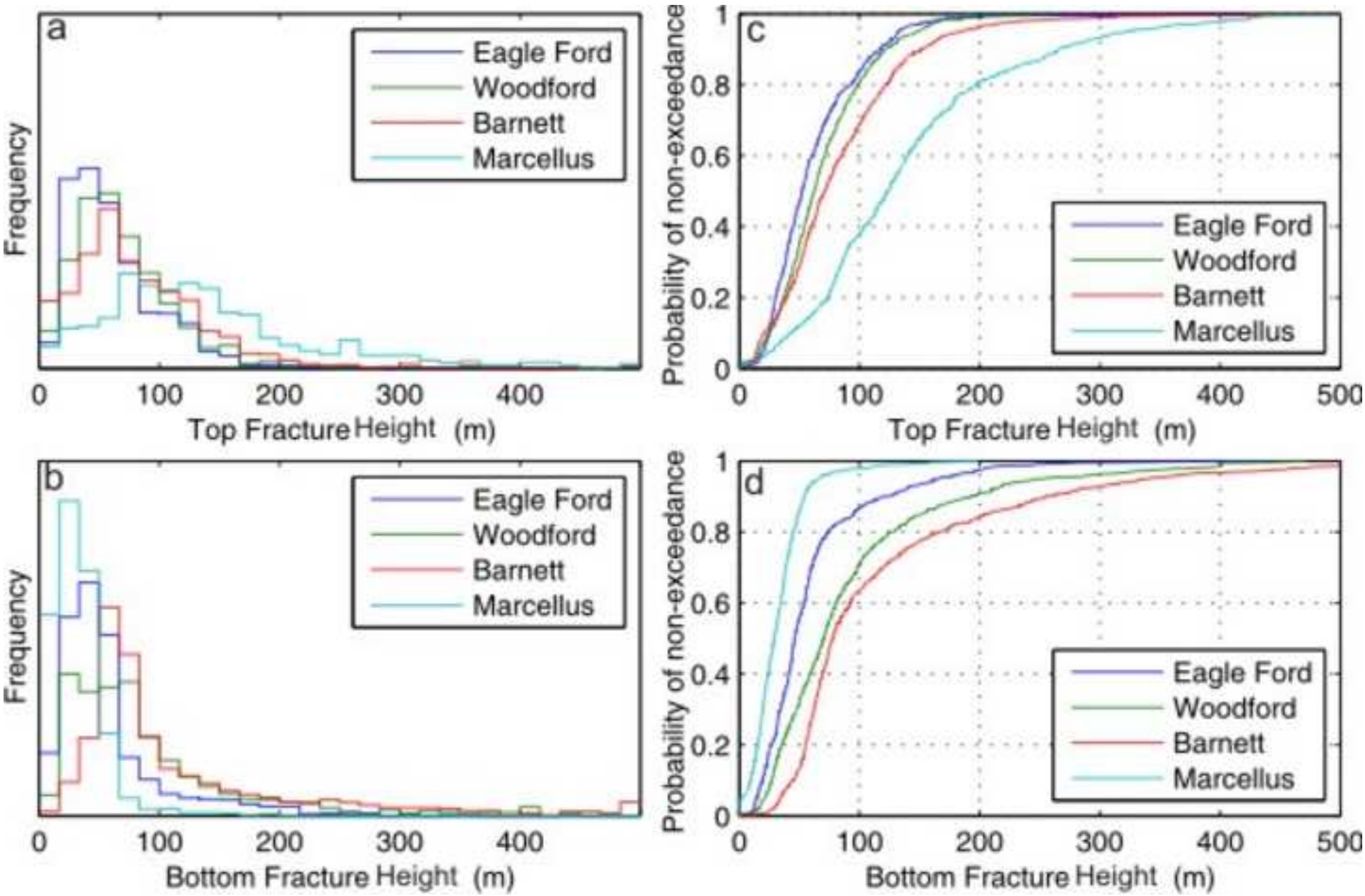

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