Written evidence submitted by Dr. James Verdon and Prof. Michael Kendall

SUMMARY

S1. Hydraulic fracturing has the potential to trigger seismic events that can be felt by local populations. However, such events are unlikely to be of sufficient magnitude to cause damage to buildings or other infrastructure. Moreover, felt seismic events are a rare occurrence, with a handful of recorded cases from hundreds of thousands of completed hydraulic fracture stimulation treatments.

S2. A "traffic light scheme" has been proposed to mitigate induced seismicity in the UK. The current thresholds are very conservative. However, there are uncertainties as to exactly how the system will be implemented that should be addressed.

S3. "Microseismic monitoring" can be used to track hydraulic fractures as they propagate. Such data can be used to optimise hydraulic fracturing operations, but can also be used to identify geohazards such as faults. Data from the USA shows that it is common for hydraulic fractures to interact with faults. However, even where this happens, larger, felt seismic events are not generated, and fractures do not tend to propagate to abnormally shallow depths such that they might pose a risk to groundwater.

S4. Microseismic data can be used to assess the risk of inducing felt seismicity. While we recognise that DECC will wish to continue with the TLS at present, we recommend that in the longer term both DECC and operators look to develop alternative systems that make use of microseismic data to mitigate induced seismicity.

S5. Multiple lines of evidence, including geophysical data, geochemical analysis, and modelling studies have indicated that the hydraulic fracturing process itself does not pose a risk to shallow groundwater supplies. Instead, where issues have arisen in the USA they have been the result of failure to ensure wellbore integrity, or of failures in the handling and disposal of fluids and materials at the surface. These issues are common to all oil and gas activities, and the UK has a strong environmental record in this regard.

WITNESSES

Dr. James Verdon *holds the position of BGS Senior Research Fellow in Geophysics in the School of Earth Sciences at the University of Bristol. He works on issues of injection-induced seismicity in oil, gas and geothermal reservoirs. He received his PhD in 2010 on Geomechanical Modelling and Microseismic Monitoring of Geological* CO_2 *Storage, and has been awarded the Keith Runcorn Prize from the RAS for Best Doctoral Thesis in Geophysics. He has published over 25 papers in leading international scientific journals. He is a member of the American Geophysical Union, the Royal Astronomical Society, and the European Association of Geoscientists and Engineers.*

Prof. Michael Kendall *is the BGS Professor of Geophysics in the School of Earth Sciences at the University of Bristol. His research interests cover pure and applied seismology, with connections to mineralogy, tectonics and engineering. He has led seismic field experiments in geologic settings ranging from the Canadian Arctic to remote parts of Ethiopia. He has published over 160 papers in leading journals and in 2011 he was elected fellow of the American Geophysical Union. He leads the Bristol University Microseismicity Project, an industry and NERC funded JIP involved with seismic monitoring in CCS, shale gas, geothermal and volcanic systems.*

STATEMENT OF EVIDENCE

1. Hydraulic fracture stimulation, like any activity that causes stress changes in the subsurface, has the potential to trigger "felt" seismicity (i.e., seismic events of sufficient magnitude to be felt by local populations). However, such incidents are extremely rare. Of the hundreds of thousands of hydraulic fracturing treatments completed around the world, we are aware of only a handful examples of felt seismicity, listed in Table 1.

Dates	Location	M_{MAX}	Reference
04/2009 – 12/2011	Horn River Basin, B.C.	3.8	B.C. Oil and Gas Commission (2012)
01/2011	Garvin County, Oklahoma	2.9	Holland (2013)
04/2011 – 05/2011	Lancashire, U.K.	2.3	Clarke et al. (2014)
07/2014	Carter County, Oklahoma	3.2	Darold et al. (2014)
09/2013 – 10/2013	Harrison County, Ohio	2.2	Friberg et al. (2014)
03/2014	Mahoning County, Ohio	3.0	Skoumal et al. (2014)

Table 1: Case examples where hydraulic stimulation is believed to have triggered "felt" seismic events.

2. Earthquakes are induced when hydraulic fracturing alters the stress acting on a fault. If the altered stress state exceeds the stability criteria, the fault will slip, triggering a seismic event. In order for a fault to be re-activated during hydraulic fracturing, it is generally accepted that the fault must be optimally oriented in the present-day in situ stress field such that it is already be close to the critical stress state. Seismicity induced in this manner is often referred to as a "clock-advance", in that the induced events are likely to have occurred naturally at an unspecified time in the future. Typically, most faults are not close to their critical stress, meaning that even if a hydraulically stimulated fracture intersects them, felt seismic events will not be induced.

3. It is widely accepted that the maximum magnitude (M_{MAX}) of injection-induced seismic events is determined by the injected volume. McGarr (2014) develops an empirical relationship, $M_O = G\delta V$, where M_O is the seismic moment released, G is the shear modulus of the rock, and δV is the injected volume. Typically, $G \approx 20\text{x}10^9$Pa. Typical hydraulic fracturing treatments use 1,000 – 2,000m^3 of fluid, resulting in a maximum seismic moment of 4x10^{13}Nm, corresponding to an $M_{MAX} \approx 3$. This volumetric limit is the likely reason why hydraulic fracturing has not generated events substantially larger than magnitude 3. Events of this magnitude can be felt by local populations, however they are unlikely to cause damage to buildings or other infrastructure. The UK typically experiences about 10 earthquakes of similar magnitude per year. The USGS equate magnitude 3 – 3.9 events with MMI scales II – III: which are described as: "*Felt only by a few persons at rest, especially on upper floors of buildings*" and "*Felt quite noticeably by persons indoors, especially on upper floors of buildings. Many people do not recognize it as an earthquake. Standing motor cars may rock slightly. Vibrations similar to the passing of a truck*".

4. At present, the Department of Energy and Climate Change (DECC) intend to use the "Traffic Light Scheme" (TLS) to regulate induced seismicity during hydraulic fracture stimulation, whereby an operator must proceed with caution if events larger than magnitude 0 are detected, and stop immediately if events larger than magnitude 0.5 are detected. This is a very conservative limit, corresponding to ground motion that is an order of magnitude smaller than that caused by slamming a door (Westaway and Younger, 2014). However, it should be recognised that this limit is intended to preclude the possibility of a larger event occurring after stimulation has ceased.

5. While the TLS is a very conservative measure, there are some issues as to its current implementation that should be addressed. Firstly, there are several different measures of earthquake magnitude that can be used to describe the size of an earthquake. Most common are "local magnitude", M_L, and "moment magnitude", M_W. Local magnitude is a simple measure, relating the recorded amplitude at a given distance to an earthquake magnitude. Moment magnitude is determined from a full inversion of the event source parameters, and is a true representation of the moment released by an earthquake. While both measures are scaled such that they are similar, they will not necessarily produce the same magnitude for a given event. This is particularly true for smaller events: Ottemoller and Sargeant (2013) show that M_L and M_W may differ by as much as 0.5 magnitude units, for example. There is scope for controversy if an event exceeds a TLS limit on one magnitude scale, but does not on another.

6. Secondly, all magnitude measurements are subject to error. For large events the signal strength is large, and measurement errors are therefore small. However, for the small events needed to operate the TLS (magnitude 0.0 – 1.0), signals are weak, and measurement errors may therefore be large (e.g. Stork et al., 2014). Furthermore, the estimated magnitude can be influenced by the type of monitoring sensor better. It is not clear how such measurement errors will be incorporated into the TLS.

7. Thirdly, operation of the TLS requires that a decision be made as to whether an event has been induced by hydraulic stimulation, or whether it is a natural event. For the small magnitude events relevant to the TLS, this will not be trivial (e.g., Maxwell, 2013). Scientific criteria by which an earthquake can be classed as "natural" or "induced" are not well established: there has been in many cases extensive and lengthy academic debate over whether a particular earthquake was "induced" or not. Typically, an earthquake is determined to be "induced" if it occurs close to the site of an operation (although no maximum distance has been defined), has a temporal correlation with activities (although no time delay between injection and an event has been defined), and represents the first instance of seismicity of this character in the area (Davis and Frohlich, 1993).

8. Earthquake scaling relationships published by the BGS imply that over 5,000 earthquakes with magnitude greater than 0.0 occur naturally in the UK every year. The vast majority of these go undetected by existing monitoring networks. Therefore it will not be possible to determine whether an event of magnitude 0.0 or 0.5 that occurs during hydraulic stimulation is the first instance of such seismicity in an area, and therefore whether it can be classed as "induced". While baseline monitoring can improve coverage (e.g. Horleston et al., 2013), 6 months to 1 year of additional monitoring is unlikely to be sufficient to fully characterise the natural rate of occurrence of small magnitude (0.0 – 1.0) events in an area. Similarly, at what distance from the stimulation site, and how long after stimulation, might an event occur for it to be considered "induced"? Even from an academic perspective, this is a subject that attracts substantial discussion. Given the heated nature of present public debate over shale gas, these uncertainties could be the source of significant controversy, especially as it is not currently clear who will make the final decision over whether an event is "natural" or "induced".

9. Hydraulically stimulated fractures can be mapped in real time as they form using a technique known as "microseismic monitoring". As the fractures propagate into the shale, they generate small amounts of seismic energy as a series of fracturing events. These events are analogous to earthquakes, but orders of magnitude smaller in amplitude, so they are commonly referred to as "microseismic events". These events cannot typically be detected above background noise levels at distances greater than 500 – 1,000m. Therefore an array of geophones (typically 10 – 20) is installed in a monitoring borehole at or near to the stimulated zone to detect events. Alternatively, given a sufficient number of geophones, weaker signals can be extracted using a beamforming-and-stacking approach (Duncan and Eisner, 2010). In such a system, a large number of geophones (typically 1,000 or more) are installed as an array at the surface. Cuadrilla have indicated that they will use this second type of monitoring array for their proposed operations in Lancashire (Cuadrilla Bowland Ltd., 2014).

10. Figure 1 shows an example of microseismic monitoring being used to map 3 hydraulic fracture stages conducted from 2 vertical wells. The microseismic events reveal the lateral and vertical extent of the fractures, and the direction in which they have propagated. In the USA, microseismic monitoring is used by operators primarily to optimise their operational efficiency and hydrocarbon recovery. Operators use microseismic data to:

- Optimise the spacing of their horizontal wells, and the spacing of fracture stages within these wells.
- Optimise injection volumes, rates and pumping strategies (using "hesitation fracs" or "zipper fracs", for example).
- Detect horizontal and/or vertical barriers to fracture propagation.
- Identify where fractures are propagating beyond the targeted hydrocarbon-bearing zones.
- Estimate the stimulated reservoir volume, and to construct fracture models to simulate future hydrocarbon production rates.
- Identify geohazards, such as faults.

11. Despite these advantages, microseismic monitoring is used on approximately 10% of hydraulic fracturing stages conducted in the USA. In his speech in December 2012, the Secretary of State for Energy and Climate Change stated that "*operators will also be required to monitor the growth in height of the frac away from the borehole. This will allow the operator to evaluate the effectiveness of the frac, but also ensure that the actual fracture is conforming to its design, and that it remains contained and far away from any aquifers*". We presume that this statement refers to the use of microseismic monitoring, although we would welcome further clarification in this regard. We anticipate that microseismic monitoring of hydraulic fracture stimulation will be widely used in the UK industry.

12. Microseismic monitoring can be used to identify potential environmental risks posed by hydraulic fracture stimulation. In particular, interactions between faults and hydraulically stimulated fractures are commonly imaged in the USA. Figure 2 shows examples where hydraulically stimulated fractures have interacted with pre-existing faults, as imaged by microseismic data. Some service contractors have estimated that they see evidence for interactions between hydraulically stimulated fractures and faults in approximately 30% of the wells they have monitored (M. Mueller, P.M. Duncan, Microseismic, Inc., *pers. comm.*). Similarly, Fisher and Warpinski (2012) state that "*such faults are commonly and easily seen in the microseismic data*". It is often asserted that faults are rare in North American shales, and that this represents a substantial difference between the USA and the UK. However, microseismic data reveals that faults are not uncommon in the USA.

13. While examples of hydraulically stimulated fractures interacting with faults are common, cases of "felt" seismic events are rare. It is clear that even where hydraulic stimulation intersects a previously unidentified fault, induced seismic events of sufficient magnitude to be felt by the public are unlikely. Nevertheless, most operators will seek to avoid faults where possible for operational reasons. Moreover, microseismic data can provide an effective means of mitigating induced events, revealing where hydraulically stimulated fractures have intersected faults.

14. The stated aim of the TLS is to preclude felt seismicity. However, as described above there remains substantial uncertainty as to how the TLS will operate in practice. In contrast, microseismic data can provide a more complete understanding of how stimulation is effecting the subsurface, and a more quantitive assessment of the risk of inducing a felt event. We are aware that DECC intend to use the TLS during preliminary shale gas operations in the UK. We recommend that the TLS remains under review, and that operators are encouraged to use microseismic data, in addition to the TLS, to mitigate induced seismicity (as described by Hallo et al., 2014, for example). In the longer term, we recommend that DECC continue to require operators to ensure that their activities do not produce seismic events, but that more flexibility is allowed as to how operators make use of a combination of TLS and microseismic data to achieve this goal. Such an approach would be more in keeping with the type of "goal-setting" regulation that is typically favoured.

15. Microseismic data is also used to ensure that hydraulic stimulation does not pose a risk to shallow, potable water sources. Fisher and Warpinski (2012) collate microseismic data from numerous shale plays in North America, concluding that in no case have hydraulically stimulated fractures propagated near to shallow aquifers. This has been the case even in more geologically complex plays, such as the Woodford Shale (described in Fisher and Warpinski, 2012). In over 90% of the cases reported by Fisher and Warpinski (2012), fractures remain within 200m of the injection zone. The few cases where fractures have propagated further represent cases where hydraulic fractures have intersected faults, in which case less than 1% of fractures have extended more than 350m from the injection zone, and the maximum recorded upward propagation was 588m (Davies et al., 2012). Our research group has independently processed microseismic

datasets from shale gas plays in the USA, and our observations have been consistent with the above observations.

16. In addition to microseismic data, modeling studies have reached similar conclusions regarding the limits to fracture propagation and fluid migration, even in the presence of pre-existing faults. Rutqvist et al. (2013) conclude that "*the possibility of hydraulically induced fractures at great depth (thousands of meters) causing activation of faults and creation of a new flow path that can reach shallow groundwater resources (or even the surface) is remote*", while Flewelling et al. (2013) conclude that "*direct hydraulic communication between tight formations and shallow groundwater via induced fractures and faults […] is not a realistic expectation based on the limitations on fracture height growth and potential fault slip*". These conclusions are also borne out by geochemical data from sites where contamination from hydraulic fracturing has been alleged. Darrah et al. (2014) examined geochemical signatures at sites where fugitive methane has been found and attributed to drilling activities. They find that "*noble gas isotope and hydrocarbon data link […] contamination clusters to gas leakage […] through failures of annulus cement, […] faulty production casings, and […] underground gas well failure. Noble gas data appear to rule out gas contamination by upward migration from depth through overlying geological strata triggered by horizontal drilling or hydraulic fracturing.*"

17. These independent lines of evidence point to the same conclusion: that the hydraulic fracturing process itself does not pose a significant risk to potable groundwater sources. Where issues have arisen in North America, they appear to have been caused either by a failure to ensure the integrity of the wellbore, or by failures in handling and disposing of fluids and materials at the surface. These risks are common to all oil and gas activities, and not specific to shale gas extraction. The UK has a strong record of regulating such activities. Incidents where wellbore integrity fails such that a leak occurs, or where fluids are spilled from a well pad, are very rare occurrences.

RECOMMENDATIONS

R1. We recommend that operators deploy microseismic monitoring systems to map hydraulically stimulated fractures. Such data will enable them to optimise their operations, but more importantly it will enable them to guarantee that fractures do not propagate beyond the target zones, and that faults are not reactivated.

R2. At present, we anticipate that DECC will require operators to follow the TLS. We therefore recommend that DECC provide further clarification as to the uncertainties outlined above, namely the choice of magnitude scale to be used, how measurement errors are to be managed under the TLS, and how natural events are to be differentiated from "induced" events.

R3. In the longer term, we believe that microseismic data will be of greater use in enabling operators to mitigate induced seismicity. We recommend that DECC considers alternative systems; allowing operators to use microseismic data to ensure that their operations do not produce felt seismic events.

R4. It is very unlikely that the hydraulic fracturing process itself will lead to groundwater contamination. The principal risks are from failure of wellbore integrity or from the surface handling and disposal of fluids and materials. It is on these issues that any future regulation should focus. However, we note that these issues are common to all oil and gas extraction, and that the UK already performs well in regards to these issues.

FIGURES

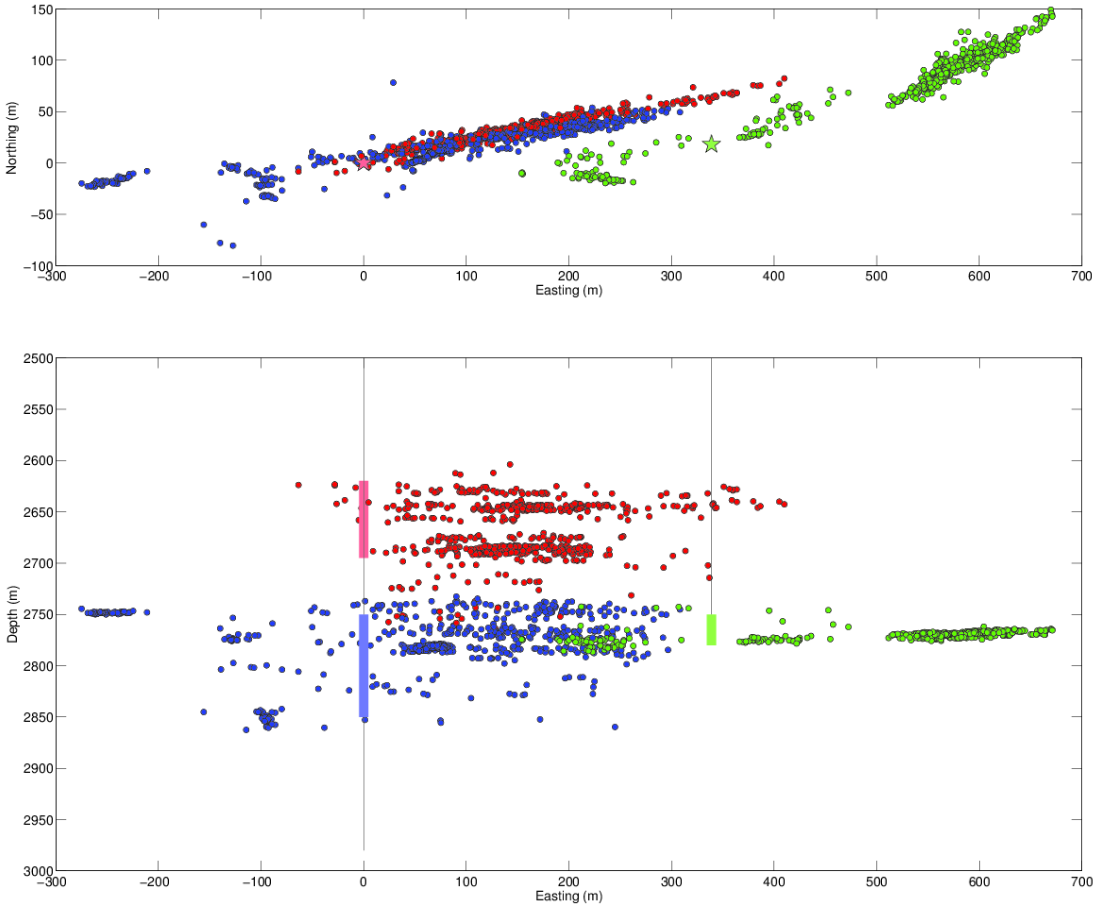

Figure 1: Example of hydraulic fractures mapped using microseismic data. The upper panel shows a map view, the lower panel shows a cross section. The positions of the 3 vertical injection stages are marked by coloured rectangles in the lower panel. Coloured dots mark the microseismic events associated with each injection stage. In each stage, fractures propagate ENE – WSW from the injection well, extending laterally for several hundred meters. Fractures do not extent vertically, and are limited to their injection zones.

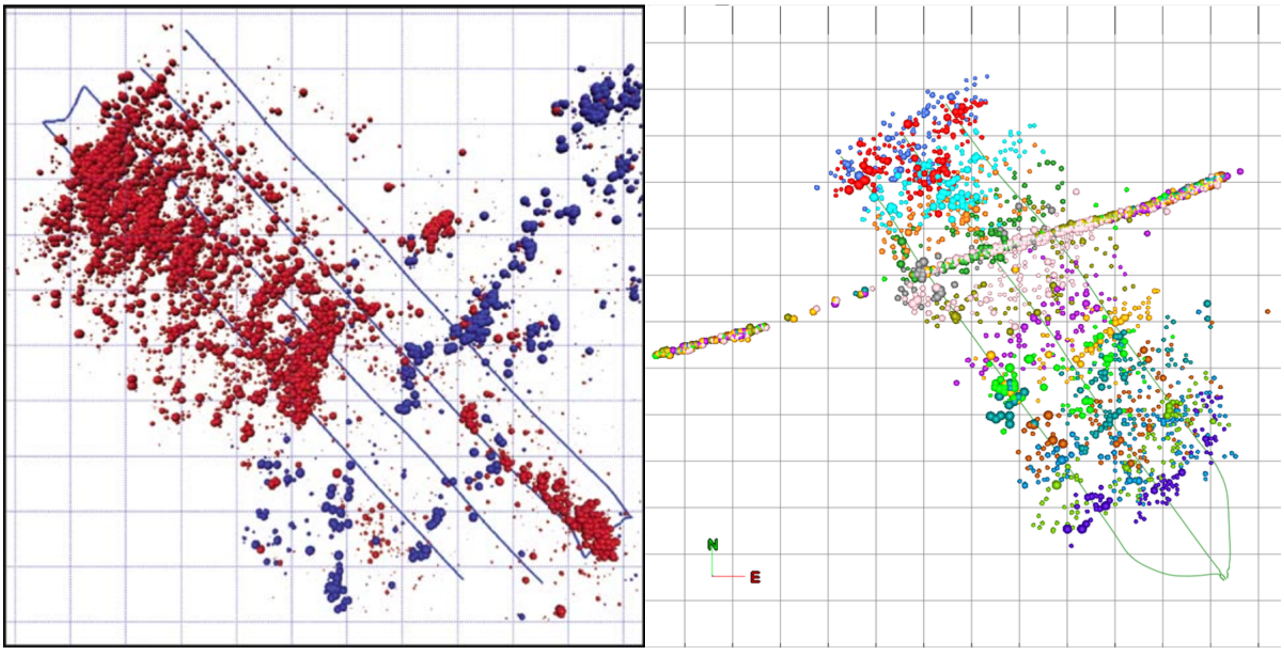

Figure 2: Examples of hydraulically stimulated fractures interacting with faults, as revealed by microseismic data. Both plots show map views of microseismic events recorded during multi-stage stimulation of lateral wells. In the left hand panel, events associated with hydraulic fractures are coloured red, while events associated with the fault are coloured blue. In the right hand panel, events are coloured by stage – the fault is clear as a linear feature cutting across the stimulated zone. Both figures kindly provided by Microseismic, Inc..

BIBLIOGRAPHY

B.C. Oil and Gas Commission, 2012. Investigation of Observed Seismicity in the Horn River Basin. [Link]

Clarke H., Eisner L., Styles P., Turner P., 2014. Felt seismicity associated with shale gas hydraulic fracturing: The first documented example in Europe: *Geophy. Res. Lett., Early View*. [Link]

Cuadrilla Bowland Ltd., 2014. Temporary shale gas exploration, Preston New Road, Lancashire: Environmental Statement: *Cuadrilla Bowland Ltd. and Arup.* [Link]

Darold A., Holland A.A., Chen C., Youngblood A., 2014. Preliminary analysis of seismicity near Eagleton 1-29, Carter County, July 2014: *Oklahoma Geological Society Open File Report*, OF2-2014. [Link]

Darrah T.H., Vengosh A., Jackson R.B., Warner N.R., Poreda R.J., 2014. Noble gases identify the mechanisms of fugitive gas contamination in drinking-water wells overlying the Marcellus and Barnett Shales: *Proc. Nat. Acad. Sci.* 111, 14076-14081. [Link]

Davies R.J., Mathias S.A., Moss J., Hustoft S., Newport L., 2012. Hydraulic fractures: how far can they go? *Mar. and Pet. Geol.* 37, 1-6. [Link]

Davis S.D. and Frohlich C., 1993. Did (or will) fluid injection cause earthquakes? – Criteria for a rational assessment: *Seis. Res. Lett.* 64, 207-224. [Link]

Duncan P.M. and Eisner L., 2010. Reservoir characterization using surface microseismic monitoring: *Geophysics* 75, A139-A146. [Link]

Fisher K. and Warpinski N., 2012. Hydraulic-fracture-height growth: Real data: *SPE Annual Technical Conference and Exhibition,* SPE 145949. [Link]

Flewelling S.A., Tymchak M.P., Warpinski N., 2013. Hydraulic fracture height limits and fault interactions in tight oil and gas formations: *Geophys. Res. Lett.* 40, 1-5. [Link]

Friberg P.A., Besana-Ostman G.M., Dricker I., 2014. Characterisation of an earthquake sequence triggered by hydraulic fracturing in Harrison County, Ohio: *Seis. Res. Lett.* 85, 1295-1307. [Link]

Hallo M., Oprsal I., Eisner L., Ali M.Y., 2014. Prediction of magnitude of the largest potentially induced seismic event: *J. Seismol.* 18, 421-431. [Link]

Holland A.A., 2013. Earthquakes triggered by hydraulic fracturing in South-Central Oklahoma: *Bull. Seis. Soc. Am.* 103, 1784-1792. [Link]

Horleston A.C., Stork A.L., Verdon J.P., Baird A.F., Wookey J.M., Kendall J-M., 2013. Seismic monitoring of drilling operations in Balcombe, West Sussex: *University of Bristol.* [Link]

Maxwell S.C., 2013. Unintentional seismicity induced by hydraulic fracturing: *CSEG Recorder* 38, 40-49. [Link]

McGarr A., 2014. Maximum magnitude earthquakes induced by fluid injection: *J. Geophys. Res.* 119, 1008-1019. [Link]

Ottemoller L. and Sargeant S., 2013. A local magnitude scale M_L for the United Kingdom: *Bull. Seis. Soc. Am.* 103, 2884-2893. [Link]

Rutqvist J., Rinaldi A.P., Cappa F., Moridis G.J., 2013. Modeling of fault reactivation and induced seismicity during hydraulic fracturing of shale gas reservoirs: *J. Pet. Sci. and Eng.* 107, 31-44. [Link].

Skoumal R.J., Brudzinski M.R., Currie B.S., 2014. Induced earthquakes during hydraulic fracturing in Poland Township, Ohio: *Bull. Seis. Soc. Am., sub judice*.

Stork A.L., Verdon J.P., Kendall J-M., 2014. The robustness of seismic moment and magnitudes estimated using spectral analysis: *Geophys. Prosp.* 62, 862-878. [Link]

Westaway R. and Younger P.L., 2014. Quantification of potential macroseismic effects of the induced seismicity that might result from hydraulic fracturing for shale gas exploitation in the UK: *Quat. J. Eng. Geol. & Hydrogeol.* 47, 333-350. [Link]

DECLARATION OF INTERESTS

Both JMK and JPV's positions are jointly funded by the University of Bristol and the BGS. In addition, JMK is the PI for an industry and NERC funded JIP, whose sponsors include major oil companies and service providers. Two of the sponsors of the BUMPS project, Cuadrilla Resources Ltd and Total S.A., are involved in UK shale gas development. In addition to their academic duties, both JMK and JPV have at various times provided consulting services to the oil industry.

30 December 2014