Written evidence submitted by James Verdon et al., University of Bristol (CCS02)

EXECUTIVE SUMMARY

With regards to the question posed by the Select Committee, 'are there any safety issues associated with capturing, transporting and storing carbon dioxide? How could they be overcome?', we submit the following:

- Large-scale subsurface fluid injection has the potential to trigger earthquakes. In addition to seismic hazard, reactivation of faults and fractures during CO_2 injection has the potential to compromise storage integrity. These risks need to be taken into account when selecting potential carbon capture and storage (CCS) sites.
- Deployment of seismometers at current large-scale CCS projects (more than 1 million tonnes of CO_2 per year) is not routine. However, two such projects, Weyburn and In Salah, have used seismic monitoring arrays, and low-magnitude induced seismic activity has been detected at both (Verdon et al., 2013). Characterisation of such seismic events, even if they are too small to be noticed by humans at the surface, is crucial for generating a complete understanding of the geomechanical response to CO_2 injection, and therefore the risk to secure storage posed.
- The detection thresholds and event location accuracies needed to assess the both the seismic hazard and the risk to storage integrity are beyond the capacity of current national seismometer networks. Therefore, dedicated seismic monitoring arrays will need to be installed at proposed CCS sites. Ideally, such arrays will be installed well in advance of injection, facilitating baseline monitoring of pre-existing, naturally-occurring seismic activity.
- Seismic monitoring should continue during the CO_2 injection phase. Identification of anomalous seismicity must be used to guide injection programs (injection rate, pressure, and the number of injection wells) to mitigate both the seismic hazard and the risk posed by fault reactivation to the hydraulic integrity of the targeted storage formation.
- We further recommend that geomechanical appraisal prior to injection should characterise rock properties, the state of stress, and the presence of any faults and fractures in and around the target reservoir,

WITNESSES

Dr. James Verdon is a NERC Early Career Research Fellow, working on issues of injection-induced seismicity in oil and gas reservoirs. He received his Ph.D 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.

Prof. Michael Kendall is Professor of Seismology and Head of 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 150 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.

Dr. Anna Stork is a Post-Doctoral Research Assistant at the University of Bristol, working on the analysis of seismic events induced by CO_2 injection and hydraulic fracturing. She received her D.Phil on the Optimisation and Application of Earthquake Location Methods from the University of Oxford in 2007.

STATEMENT OF EVIDENCE

Induced Seismicity Potential

The occurrence of a magnitude (M) 5.0 earthquake during geological disposal of waste fluids at the Rocky Mountain Arsenal during the mid-1960s established the potential for subsurface fluid injection to trigger seismicity. Subsequent examples of injection-induced seismicity, listed in Table 1, are now well established (see review papers by Nicholson and Wesson, 1990; Davies et al., 2013; and Ellsworth, 2013).

Table 1 lists known examples where subsurface injection of waste fluid has triggered seismicity, including fluid injection rates, and the volume of fluid injected at the time that the largest earthquake occurred. For comparative purposes, a typical coal-fired power plant produces approximately 3.5MT of CO_2/year. At reservoir conditions, this corresponds to an injection volume of $5\times10^6 m^3$/year, or $4.2\times10^5 m^3$/month. Assuming a 30-year project duration, this would result in a total injection volume of $150\times10^6 m^3$. Figure 1 compares injection rates and volumes known to have triggered seismic activity with the rates and volumes required to sequester the emissions from a single coal-fired power plant: the injection rates and volumes proposed for CCS far exceed those known to have triggered the seismic events listed in Table 1. Therefore, the need to monitor induced seismicity du–ring CO_2 injection operations is clear.

Induced seismicity poses two major threats to secure CO_2 storage. Should induced seismic events occur near to populations, the events themselves may pose a hazard. Moreover, we note that recent shale gas extraction operations have experienced severe delays due to a lack of public acceptance over triggered seismicity, even though the induced events were too small to have caused any significant damage (Green et al., 2012). The public appears to be less willing to tolerate seismic activity induced by subsurface operations, of any kind, than it was in the past with activities such as coal mining.

The triggering of seismicity during CO_2 injection implies the presence of active faults and fractures in and around the target formation. Supercritical CO_2, with a density of ~650 – 800kgm^{-3} at reservoir conditions, is significantly lighter than formation brines with densities of ~1050 – 1200kgm^{-3}, meaning that caprock integrity is vital to guarantee secure storage. This is a crucial distinction to make between CCS and the storage of water-based waste fluids. Active faults that run through otherwise sealing overburden layers may provide a pathway for buoyant CO_2 to migrate back to the surface. Similarly, triggered seismic events have the potential to deform well bores and/or fracture well-bore cements, again providing a pathway for buoyant CO_2 to return to the surface.

We note that the highest profile and strongest criticism of CCS derives from considerations of the geomechanical response to CO_2 injection: Zoback and Gorelick (2012) directly identify the risks posed to secure storage by geomechanical deformation; similarly, although ostensibly a paper modelling reservoir pore pressure increases during injection, the limiting factor identified by Economides and Ehlig-Economides (2009) is that there will be an upper pressure that cannot be exceeded without risking the integrity of the seal by generating fractures.

Occurrence Rates of Induced Seismicity

It is an oft-repeated canard that the injection-induced seismicity is a rare occurrence. There are over 140,000 Class II injection wells in the USA, yet only a handful have been associated with induced seismicity. However, this apparent scarcity of induced seismic events can in part be attributed to the detection limits of national seismic

Figure 1: Fluid injection rates (left) and volumes (right) known to have triggered seismic activity, in comparison to that needed to sequester the emissions from a single coal-fired power plant (green columns). The CCS scenario shows the volume of a single year of emissions. Project names are listed in Table 1.

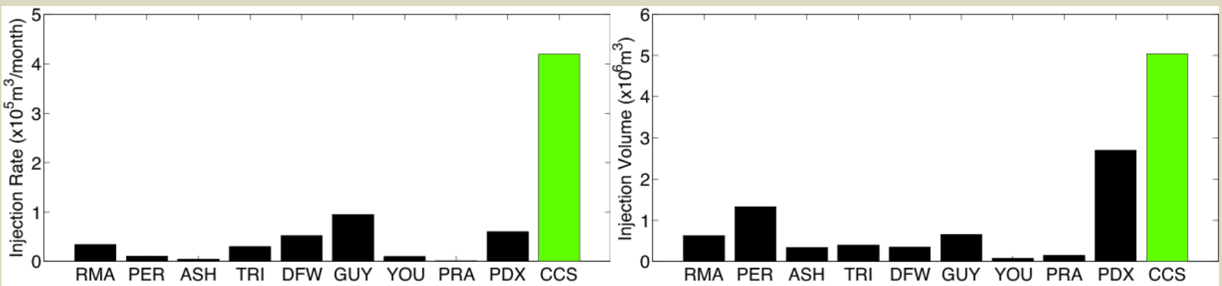


Table 1: Examples of injection-induced seismicity discussed in this paper. Notes: (1) Maximum injection rate. (2) Based on Ahmad and Smith (1988)'s maximum modelled injection rate of 0.0042m³/s. (3) Based on Seeber et al. (2004)'s estimate of 164m³/day. (4) Based on Shirley (2001)'s comment of 2.5 million barrels injected in a year. (5) Based on Frohlich et al. (2010)'s maximum rate of 11,000 barrels/day.

ID	Project	Years of injection	Maximum Magnitude	Injection volume at M_{MAX} (x10^5m^3)	Injection Rate (m^3/month)	Reference(s)
RMA	Rocky Mountain Arsenal, CO	1961-1968	5.3	6.25	34000[1]	Major and Simon (1968); Hsieh and Bredehoeft (1981)
PER	Perry, OH	1975-1986	5.0	13.3	11000[2]	Nicholson et al. (1988); Ahmad and Smith (1988)
ASH	Ashtabula, OH	1987-1994	4.3	3.4	5000[3]	Seeber et al. (2004)
TRI	Trinidad, CO/NM	1988-present	4.6	4	30000[4]	Shirley (2001); Meremonte et al. (2002)
DFW	Dallas-Forth Worth, TX	2008-2009	3.3	3.5	52000[5]	Frohlich et al. (2010; 2011)
GUY	Guy-Greenbrier, AR	2010-2011	4.7	4.6	95000	Horton (2012)
YOU	Youngstown, OH	2010-2011	4.0	0.8	10000	Ohio Department of Natural Resources (2012)
PRA	Prague, OK	2010-2011	5.7	1.5	1400	Keranen et al. (2013)
PDX	Paradox, CO	1991-2013	4.3	27	60000	Ake et al. (2005)

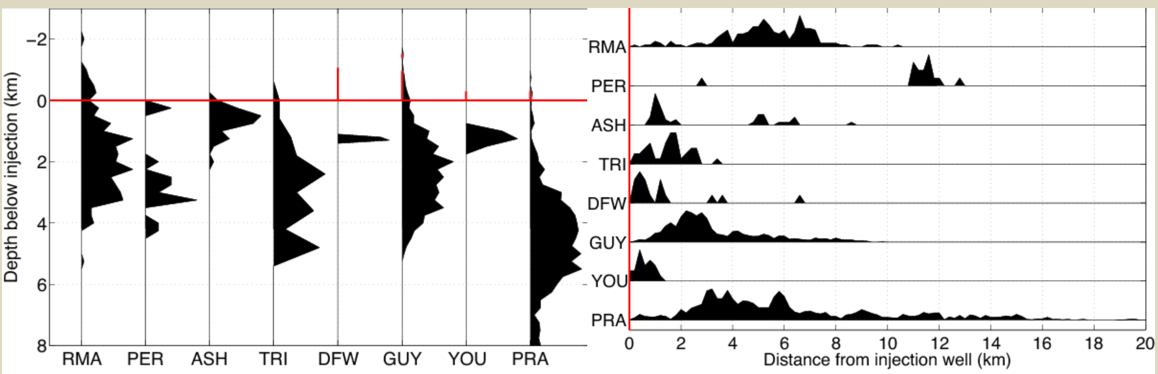
monitoring arrays, and in part to the smaller injection volumes of many wells.

Frohlich (2012) demonstrated this issue using data from the Earthscope USArray, a portable array of seismometers that crossed the Barnett Shale region (Texas) from 2009 to 2011. Frohlich found that 5% of high volume waste water injection wells had associated clusters of induced seismicity. The majority of these events had magnitudes between M2.0 – M3.0, and had gone undetected on national seismic arrays.

Any estimate of the occurrence rate of induced seismicity will be strongly controlled by the detection threshold of the seismic arrays in question. The triggering of larger seismic events that pose a significant seismic hazard is rare. However, as discussed above, triggering of smaller events (M $\leq$ 3.0) may pose a risk to secure CO_2 storage if they create or reactivate fractures and faults that provide a hydraulic connection frm the reservoir to the surface. Regional and national seismic networks often do not have sufficient detection thresholds to identify such events, and therefore their rate of occurrence is likely to be significantly underestimated.

Spatial Distribution of Induced Events

Figure 2: Normalised histograms of event depths (left), scaled such that 0 corresponds to the deepest injection level, and of lateral event distance from the nearest injection well (right). The majority of events occur at and below the injection depth, and within 20km of the injection well.



Given the risk to secure CO_2 storage posed by induced earthquakes, the spatial distributions of such events are highly pertinent. An event occurring in the sealing caprock, close to the injection point, will pose a greater risk to secure storage than an event occurring below the reservoir, or at greater distance from injection. Furthermore, the radial extent of induced seismicity may help to delineate a radius of influence for future CCS sites, defining the lateral extent away from the injection well that may be affected by CO_2 injection in some manner. This radius of influence will represent the minimum distance over which modelling and appraisal studies should be conducted prior to injection.

In Figure 2 we plot normalised histograms of event depths relative to the injection interval, and event distance from the water injection point, for the case examples that have sufficient event location accuracy to facilitate analysis of this kind. We observe that in the majority of cases, at least some seismicity occurs at the injection depth, and that the majority of the seismicity occurs below target storage interval.

It is of some significance that the majority of the induced seismicity appears to occur below the storage interval. Active faults provide potential pathways for fluid migration, meaning that active faults in the caprock pose a risk to secure CO_2 storage, so the fact that seismicity generally occurs below the injection intervals must be considered favourable for CO_2 sequestration. However, we are unsure as to why the majority of events should occur below the reservoirs, and so we cannot be certain that this phenomenon would be repeated at CCS sites.

In terms of lateral distance from the injection wells, we note that the majority (62%) of events occur within 5km of the injection wells, while 99% of events occur within 19km. Therefore we suggest a minimum radius of influence, over which geomechanical appraisal should be conducted prior to CO_2 injection, of 20km from the injection well.

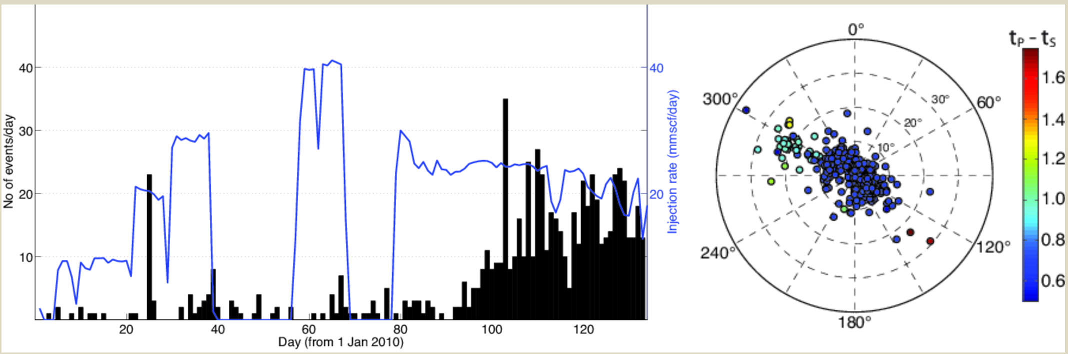
Case examples of seismic monitoring during CO_2 injection: In Salah and Aneth

Seismometer arrays have been successfully deployed at several pilot CO_2 injection projects, imaging fracture networks created or re-stimulated by CO_2 injection, including at Weyburn, In Salah, and Aneth. At least some degree of induced seismicity, albeit of small magnitude, has been detected at each site. Although detected events are too small to be felt at the surface, they have implications for the security of the storage formation.

At In Salah, the presence of a fracture network extending through the target storage formation, and into the lower part of the sealing caprock, was first identified using satellite monitoring of ground surface deformation (Vasco et al., 2010). This observation precipitated the deployment of a geophone array to monitor induced seismicity. Unfortunately, technical issues meant that only 1 of the 6 stations deployed was fully functional, which has prevented accurate location of events.

Nevertheless, during 4 months of monitoring, over 700 induced events were detected (Figure 3). The majority of these had magnitudes close to M-1.0, with the largest having a magnitude of M1.0. Although precise event location was not possible with a single geophone, the arrival azimuths of the seismic waves (trending NW-SE) and the time-differential between P wave and S wave arrivals (a

Figure 3: Induced seismic activity at In Salah. Left panel shows CO_2 injection rate, and rate of seismicity, during the first 3 months of 2010. Right panel shows the incidence azimuth and inclination of the seismic waves at the single geophone, coloured by the differential arrival times of P and S waves (a proxy for distance from the geophone).



proxy for the distance of the event from the geophone) are consistent with the presumed location of the fracture network inferred from satellite deformation data (Verdon et al., 2013).

Unfortunately, the monitoring array was installed 5 years after the beginning of injection. This means that it is not possible to determine whether this fracture network was naturally active prior to CO_2 injection, nor how it was affected during the early stages of CO_2 injection. This omission demonstrates a clear need for the installation of monitoring arrays prior to the start of injection at future CCS projects.

At Aneth, Utah, a mature oilfield was converted into a CCS/EOR operation, injecting CO_2 into the reservoir in order to extract more oil (Rutledge, 2010). As a result, waste brine that was re-injected into the reservoir was instead re-injected into an underlying aquifer. A downhole geophone array was installed to monitor seismicity induced by these processes.

During the study period (2008-2009), over 1,000 events were detected with magnitudes from M-1.3 to M0.75 (Figure 4). Event locations revealed the presence of two fracture zones that were stimulated by fluid injection. These zones were located below the oil reservoir, closer to the brine-flooding zone, which is believed to be the cause of the induced events.

These studies highlight the importance of monitoring induced seismic activity at future CCS sites. Even if the seismic hazard posed by low-magnitude events is small, monitoring of this type provides the opportunity to detect stimulated fracture networks that can have implications for the hydraulic integrity of the storage formation.

Case Study: Closely-Monitored Induced Seismicity at Paradox Valley, Colorado (Ake et al., 2005)

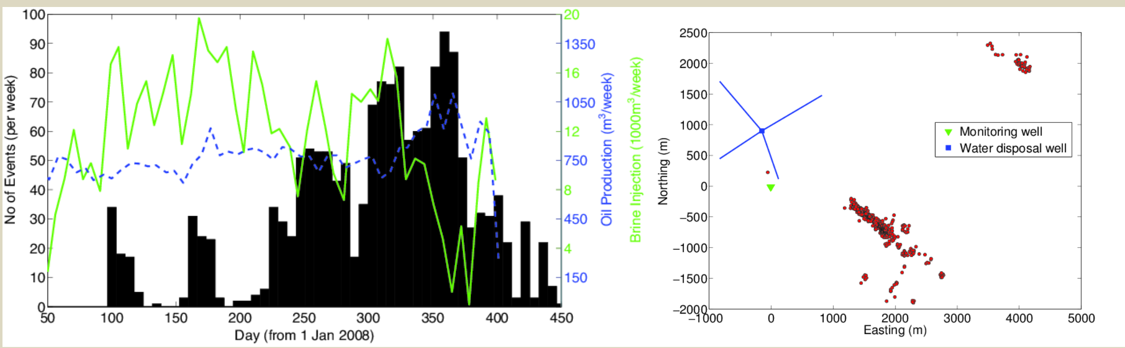
For many of case examples discussed above, seismic monitoring was deployed in response to felt earthquakes, rather than pro-actively prior to the start of operations. One exception to this rule is the Paradox Valley brine injection project, Colorado, as outlined by Ake et al. (2005). This case example shows how comprehensive seismic monitoring can be effective in minimising the risks posed by injection-induced seismicity.

At Paradox Valley, Colorado, brine from the shallow Paradox Valley aquifer is produced and re-injected at depths of 4.3-4.8km into basal sedimentary formations and crystalline basement in order to reduce the salinity of the Colorado River. Injection testing was conducted from 1991 to 1995, prior to full-scale injection in 1996. A dedicated seismic monitoring array was installed in 1985, before the injection tests.

During the 6 years prior to injection, 6 small earthquakes were identified, none of which were located within 10km of the future injection points, establishing a baseline rate of seismicity. Between 1991 and 1995, 7 injection tests were conducted, where fluids were injected at various rates and pressures, for between 2 weeks and 8 months. During each test, seismic events were identified that were associated with the injection. Full-scale injection began in 1996, and 111 days after the onset of continuous injection, earthquakes were detected with M0.0 – M3.0, 15 of which had M $\geq$ 2.5 and were felt at the surface.

Seismicity continued, and 2,000 such smaller magnitude events had been detected by mid-1999, when two larger M3.6 and M3.5 events occurred. In

Figure 4: Induced seismic activity during CO_2/EOR and brine disposal at Aneth, Utah. Left panel shows the seismicity rate, oil production rate, and brine disposal rate. Right hand panel shows a map of event locations, which delineate two fracture zones trending NW-SE. Events are located below the oil reservoir, closer to the brine flooding zone.



response to these events, which were deemed to be unacceptably large, the injection program was modified. Every 6 months, a 20-day injection hiatus was established. These injection hiatuses were intended to allow reservoir pressures to diffuse, reducing the risk of induced seismicity. Although this modified regime did reduce overall seismic activity, in mid-2000 an M4.3 earthquake was triggered. Following this large event, the injection regime was further modified, and injection rates were reduced by 30%, maintaining 20-day hiatuses every 6 months. Induced seismicity under the new injection program reduced to acceptable rates, with no further seismic events with magnitudes greater than 2.8.

Paradox Valley provides a good example of management of induced seismicity. Baseline monitoring prior to injection provides an estimate of low-level, naturally-occurring seismicity. During operations, injection rates and pressures can be modified to reduce the risk posed by either larger earthquakes, or by events that appear to compromise the integrity of the sealing caprock.

Recommendations

The above case examples highlight the importance of deploying seismic monitoring arrays during CO_2 injection operations. Although it is commonly assumed that injection-induced seismicity is rare, Frohlich (2012) shows that events of M2.0 or greater have occurred at 5% of wells that inject at rates greater than 24,000m^3/month in the Barnett Shale area, while several pilot CO_2 injection operations have detected induced seismicity of some kind (e.g., Verdon et al., 2013).

Given the potential risks of induced seismicity posed by CCS operations, it is worth considering what actions can be taken to ameliorate these risks. Nicholson and Wesson (1990) make a number of suggestions, including: selecting sites with high transmissivity and storativity; making estimates of the stress state at potential sites; selecting sites that do not have evidence for faulting (though of course, an absence of evidence does not necessarily prove the absence of a fault); and choosing sites in regions with low rates of natural seismicity. In Table 2 we make a number of recommendations regarding geomechanical appraisal and seismic monitoring that we suggest should be undertaken prior to and during the operation of a CO_2 sequestration site.

Table 2: Recommendations for geomechanical appraisal and seismic monitoring of CO_2 sequestration operations.

Recommendation	Comments
Evaluation of historical regional seismicity	Use regional event catalogues and historical information. Historical events *may* indicate the maximum magnitude that could be generated during injection
Search for faults within radius of influence	Large events will most likely occur on pre-existing faults, which should be avoided if possible, especially if optimally oriented within the present-day stress field. Faults may be observed in 3D seismic data, in wellbores, or from surface expression. Case examples discussed above suggest a minimum search radius of 20km from the injection site.
Coupled numerical modelling of fluid-flow/geomechanical processes	Fluid-flow models compute pore pressure increases caused by injection. Geomechanical models compute the stress changes caused by pore pressure changes, allowing the geomechanical impact of the proposed injection program to be predicted.
Installation of local seismic network at least 6 months prior to injection	A local network might consist of 10 – 20 seismometers, placed such that they cover a region at least 10km in radius from the injection point. Installation 6 months prior to injection will allow any low-level background seismicity to be characterised.
Management of injection program based on observed seismicity	Injection rates and pressures can be modulated in response to observed seismicity. If rates and magnitudes of seismicity are deemed to be too high, injection rates/pressures can be reduced. If little or no seismicity is detected, injection rates might be increased if necessary. Such a scheme might be managed by a traffic light program as proposed for seismicity induced by shale gas extraction.

Of particular significance, we recommend that any faults within the 20km radius of influence be fully characterised prior to injection. Of equal importance is the need to install dedicated seismic monitoring arrays prior to injection, allowing a baseline of naturally-occurring seismicity to be established. During the operational phase, a seismic monitoring array can establish whether injection is triggering seismicity, and determine whether this poses a seismic hazard, or a risk to storage integrity. If rates and magnitudes of seismicity are deemed to be too high, injection rates/pressures can be reduced. Such a scheme might be managed by a traffic light program as proposed for seismicity induced by shale gas extraction.

Seismic monitoring arrays may take one of two options: a downhole array of geophones, or a surface seismometer array. Downhole arrays, such as that deployed at Aneth and Weyburn, have a lower detection threshold, allowing the identification of events potentially as small as M-3.0. However, their detection range is limited, being unable to accurately locate events more and 1 – 2km from the array. Such an array is most suitable when placed near to the injection well in order to detect near-field effects.

The alternative is a surface-based array of 10 – 20 seismometers, deployed over an area of 5 – 20km. Such an array would have a higher detection threshold, possibly unable to detect events smaller than M0.0. However, such an array would have a wider aperture, allowing accurate location of events at greater distance from the injection well. Such an array would be better suited to image the impact of CO_2 injection on nearby faults.

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