Enchanting shale gas reservoir characterization using hydraulic fracture microseismic data

Shawn Maxwell1* and Mark Norton2 present a case study showing how microseismic data can be a useful part of the mix of geotechnical information sources that, when combined, provide valuable information about shale gas reservoirs.

Shale gas has more than doubled the natural gas reserves and resources in North America according to estimates by IHS CERA, adding 1200 tcf of shale gas in the US and 500 tcf in Canada. Knowledge gained in North America during the last few decades is now being used to benefit the increased interest in shale gas around the world. In Europe, shale gas is being explored in several countries, including Poland, Austria, England, Germany, Hungary, and Sweden.

Mudstones and shales are generally considered to be the source rock for most hydrocarbon reservoirs. Many still contain large volumes of gas but, because of their low permeability, they are rarely economic to produce using conventional drilling and well completion technologies. Natural fractures can improve permeability, but in gas shales they usually do not provide adequate pathways for sufficient flow of hydrocarbons into a well. Most gas shales require long horizontal wells, positioned accurately to maximize exposure to the most productive zones, and reservoir stimulation – particularly hydraulic fracturing – to increase the rate at which hydrocarbons can be produced from the rock formation. Fluids are pumped into multiple isolated stages along the well at high pressure causing the formation to crack. The composition of the fluid used varies depending on criteria such as formation mineralogy and permeability. Solid proppant materials, typically sieved round sand grains or man-made ceramic spheres, are added to the fracture fluid. These solids hold the fractures open after injection stops, so the propped hydraulic fracture becomes a conductive path through which fluids can flow from the rock formation to the well.

Experience in North America has shown that gas production and recovery rates vary considerably, not only from one well to another but also between fracturing stages along a single well. The material properties of shales exhibit high levels of vertical and lateral heterogeneity resulting from depositional and post-depositional processes that include diagenesis, interaction with organisms, thermally activated geochemistry, and movement of mineral-laden fluids. In addition, existing fractures and local stress fields have a major impact on the effectiveness of hydraulic fracturing processes. Generating enough surface area for gas to flow requires a thorough understanding of the mineralogy and stress regimes in the rock.

Integrating information
Collecting and integrating different sources of knowledge about shale reservoirs is the key to gaining competitive advantage by avoiding non-productive acreage, selectively drilling the ‘sweet spots’ and effectively stimulating the wellbore. Surface geological studies and high quality 3D seismic data provide valuable field-wide data before development drilling. Important information acquired during and/or after drilling includes resistivity, gamma ray, neutron density measurements, as well as sonic logs, rock cores, downhole spectroscopy measurements, and production data. Integrating these sources of information helps in the understanding of reservoir heterogeneity in terms of mineralogy and organic content, as does learning how stress varies horizontally and vertically near a well bore and across the reservoir. Bringing all the information together requires advanced software to enable model-centric analysis in a shared subsurface representation. Integrated ‘seismic-to-simulation’ software allows companies to incorporate all the data elements in one subsurface model.

Microseismic data
Hydraulic fracturing results in microseismic events that can be recorded at the surface or from monitor wells to locate and help characterize the fractures. Microseismic imaging can provide valuable information about a reservoir helps to design the placement and completion of wells. In some cases, the microseismic activity induced by the stimulation is consistent with relatively simple, planar fractures while, in other cases, interaction with pre-existing fracture networks results in complex fracture networks growing in multiple orientations. Behaviour ranging from simple to complex fractures has been observed in multi-stage stimulations within single horizontal wells (Cipolla et al., 2010). The variability in fracture complexity depends on the geometry of the pre-existing network as well as the in-situ stress state. Fracture complexity is thought to be enhanced in the presence of pre-existing fractures at an angle

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Why are the microseismic events large along Well-C?
Why are there no microseismic events towards the NE?
Why do the microseismic events tend to go towards the SW?
Why is the geometry of the microseismic events different near Well-A?

Analysis of the microseismic data
Different distances between the open perforations and the monitoring well are a cause of variation in the quality and quantity of the microseismic data between treatment stages. To lessen this impact, analysis was restricted to only data from fracturing stages closest to the monitoring well.

Analysis of the magnitude of microseismic events versus distance to the monitoring array showed how smaller magnitude microseismic events are recorded close to the observation well. The analysis was used to define a lower magnitude limit – in this case a magnitude limit of -2.2 – above which events would be recorded regardless of where they were located within a distance of 1000 m, thus removing the detection-distance bias. This subset is shown in Figure 3.
Microseismic events recorded during the Well-C fracture treatments were larger in magnitude than those recorded while treating the other two wells, suggesting interaction with pre-existing faults. There is a distinct lack of seismic response NE of wells B and C within the detection limits of 1000 m around the observation well, even though events above magnitude -2.2 would have been detected if they had occurred.

Seismic moment is a robust measure of the source strength of the microseismic event and provides insight into the reservoir deformation (Maxwell et al., 2006). Figure 4 shows contours of the logarithm of seismic moment density. The seismic moment or deformation density along wells B and C is relatively high, which is consistent with fault activation. While the number of events is also high around Well-A, the deformation level is smaller than near the other wells. The deformation SW of Well-C is low, indicating relatively few small magnitude events in this region. The few events that did occur happened late in the associated stages.

The frequency-magnitude relationship was also investigated. The number of events typically follows an exponential
In summary, microseismic magnitudes, seismic deformation density, \( b \)-values, and composite focal mechanisms indicate that the large events occurring along wells B and C are consistent with activation of a pre-existing fault or fracture network striking NW-SE. Any comparable microseismic events to the NE would have been detected. Apparent asymmetry towards the SW is not related to detectability. The events near Well-A clustered in a NE-SW lineation are consistent with a simple, planar hydraulic fracture oriented orthogonal to the pervasive minimum stress direction, based on magnitudes, seismic deformation density, \( b \)-values, and composite focal mechanisms.

### Treatment data

All fracturing treatments were placed at 10 m\(^3\)/min ± 0.6 m\(^3\)/min, with the exception of stage 3 in Well-C when a high near wellbore pressure loss resulted in a lower average injection rate of 7 m\(^3\)/min. Due to the close proximity of the wellbores, similar treatment responses would be expected in wells A, B, and C. However, surface-treating pressure data indicated that not only did the wells respond differently from wellbore to wellbore, but that there were also notably different responses for different stages in the same wellbore. Stage 1 of Well-B and stage 3 of Well-C were particularly anomalous. The highest breakdown pressures of the campaign were observed in Well-C, stages 3 and 5. Well-C is located in the area with higher PR, which would lead to higher overall stresses and near-wellbore stress concentrations, and hence would be expected to exhibit higher breakdown pressures. Closure pressures were measured from mini-frac injection/fall-off tests for the first stage in each well and were 27.4 kPa/m, 22.5 kPa/m, and 23.5 kPa/m for wells A, B, and C respectively. Pressure decline data was not available for subsequent stages due to operational constraints.

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Instantaneous shut-in (ISIP) gradients at the end of each propped fracture treatment plotted at the perforation locations (Figure 7) illustrate the likely areal variation in stress regime. The relatively high ISIPs coincide approximately with the higher PR regions, possibly related to high stress. Although the
Ant-tracking does not provide a strong indication of a pre-existing fault in this region, although other faults are apparent elsewhere with a similar strike. It should be noted that ant-tracking searches for faults with an apparent throw, implicitly assuming strain release associated with earlier tectonic movements. Faults with small amounts of throw and potentially subseismic resolution are more likely to be tectonically loaded and prone to releasing seismic energy due to effective stress changes and lubrication associated with hydraulic fracturing. Therefore, the microseismically activated fault systems may be difficult to resolve with seismic reflection data. Ant-tracking results just below the reservoir provide evidence of a deeper fault network (Figures 9 and 10), and the observed microseismic deformation seems to be associated with the activation of the vertical extension of this fault.

Why are there no microseismic events towards the NE? If microseismic responses with magnitudes -2.2 or greater had occurred further to the NE, it would have been detected. While mapping of PR suggests significant reservoir heterogeneity, it is important to note that the entire reservoir has relatively low PR. It is therefore unlikely that the NE region with higher PR would have a significantly different fracturing mode than the rest of the reservoir. Deformation could have occurred without a large seismic event, but even very small magnitude events would have been detected, especially for the closest stages. It can be postulated that the hydraulic fracture interacted with the fault system described above, which acted as a barrier to the hydraulic fracture extending further to the NE. As long as the permeable open fault allows fluid penetration within the fault network, it is easy to imagine that it would be unlikely to create a new hydraulic fracture. Well-C, however, does have an indication of microseismic response to the SW of the well, occurring later in each stage, which suggests that eventually the hydraulic fracture does start to grow out of the fault network.

Production data
Daily production data for the three wells (Figure 8) show that when production on Well-B starts, production on Well-A drops, suggesting interference between the two wells. The locations of microseismic events recorded while treating wells A and B overlap, which is consistent with the possibility of well interference.

Conclusions
Why are the microseismic events large along Well-C?
The seismic deformation, b-values, and focal mechanisms all point toward interaction of the hydraulic fractures with a NW-SE striking fault system. While the fault interaction is predominantly associated with fracturing wells B and C, a small indication is found for the NE extent of the Well-A microseismic response. Ant-tracking does not provide a strong indication of a pre-existing fault in this region, although other faults are apparent elsewhere with a similar strike. It should be noted that ant-tracking searches for faults with an apparent throw, implicitly assuming strain release associated with earlier tectonic movements. Faults with small amounts of throw and potentially subseismic resolution are more likely to be tectonically loaded and prone to releasing seismic energy due to effective stress changes and lubrication associated with hydraulic fracturing. Therefore, the microseismically activated fault systems may be difficult to resolve with seismic reflection data. Ant-tracking results just below the reservoir provide evidence of a deeper fault network (Figures 9 and 10), and the observed microseismic deformation seems to be associated with the activation of the vertical extension of this fault.

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hydraulic fracture in Well-B propagated into the network created during stimulation of Well-A. The SW progression from each well is towards the direction of lower PR. As discussed in Norton et al. (2010) the PR can be inversely correlated to quartz-clay content and could be related to a change in the mode of fracturing. Material property changes will also result in associated elastic stress changes through the reservoir (see, for example, Cipolla et al, 2010). Furthermore, the faulting shown by the ant- tracking also implies elastic and inelastic stress variations, which in turn will also change the material properties. In addition, a constrained, horizontal stress effect is associated with transverse strain resulting from the vertical lithostatic load, which is given by $\sigma_{H} = \sigma_{b} = (\nu/(1-\nu)) * \sigma_{v} + \sigma_{tectonic}$ and would result in lower stresses in lower PR material. The stresses in the SW direction would be lower due to this effect, resulting in more hydraulic fracture growth in that direction. The observed ISIP gradients are also consistent with lower stresses in the lower PR regions. While the specific impact of these different factors is beyond the scope of this article, there is a clear correlation between the asymmetric SW growth and the low PR region.

Why is the geometry of the microseismic events different near Well-A?
The microseismic events associated with stimulation of Well-A are, as expected, distributed in the maximum stress direction. Therefore, Well-A appears to be anomalous simply due to the lack of fault activation seen around wells B and C.

Summary
Hydraulic fracturing of the three wells in this study resulted in significant differences in the microseismic response. Interaction of the hydraulic fractures with a pre-existing fault resulted in relatively large magnitude microseismic response along the NE edge. In some cases, relatively simple, planar hydraulic fractures were created in the expected NE-SW direction, although the fractures tend to preferentially grow towards the SW in the direction of lower PR where material properties and stresses are different. Understanding the hydraulic fracture response in

Figure 9 Microseismic events and ant-tracking image.

then moves in a SW direction similar to the rest of the wells. Therefore, the lack of microseismic event towards the NE is attributed to fracture asymmetry associated with the fault system near wells B and C.

Why do the microseismic events tend to go towards the SW?
The microseismic response from each well grows preferentially in a SW direction. For example, some events to the NE of Well-A reach as far as Well-B, although the majority of microseismic activity is in the SW direction. The furthest NE microseismic events could be related to stress-induced deformation of the fault. As previously discussed, Well-B microseismic response appears to overlap with the Well-A activity, suggesting that the

Figure 10 Ant-tracking volume and corresponding seismic section showing two interpreted faults (red dashed lines). Right side is zoomed in region showing relationship with microseismic.
this region has enabled better well placement for more optimal hydraulic fracture geometry and improved production rates, in addition to better completion designs with closer perforation clusters to increase reservoir contact in future wells.

**Acknowledgements**

This article is based largely on SPE 140449 ‘Enhanced Reservoir Characterization Using Hydraulic Fracture Microseismicity’ presented at the SPE Hydraulic Fracturing Technology Conference and Exhibition, The Woodlands, Texas, USA, 24–26 January 2011.

**References**


