Comparison of microseismic results from the Bakken Formation processed by three different companies: Integration with surface seismic and pumping data

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Summary

In May, 2010 Hess acquired its first microseismic survey in the Beaver Lodge area, North Dakota, over a 2-day time period. In conjunction with this project Hess also acquired a walk-around, offset, and zero-offset VSP to enable estimation of azimuthal anisotropy and generation of a 3D velocity model for proper microseismic event placement. Three different companies were contracted to process the data resulting in widely varying microseismic locations. Rather than accepting externally processed microseismic events that show completely different fracture geometries, Hess is developing an internal methodology to review event picking, 3D velocities, and survey geometries that will lead to dependable results.

This presentation will discuss general processing methodology differences and acquisition problems that may have contributed to the inconsistencies. Integrating surface and pumping data with the microseismic reveals that incorporating a 3D anisotropic velocity model produces more reliable results.

Introduction

In recent years there has been a surge in microseismic monitoring of frac jobs due to the high level of interest in unconventional reservoirs. These reservoirs have such low porosity and permeability they must be fractured to be produced, and operators want the ability to map where the rock is breaking. Once the fractures are delineated, they can be incorporated into reservoir models to help predict production, guide the well program, and calculate reserves. This requires a level of dependability not yet demonstrated by current practices. Geophysicists must apply the same rigor to processing microseismic as they have for surface seismic processing. Though this technology has roots in the highly-studied subject of earthquake seismology, it has often been kept within engineering departments. Many of the lessons learned by seismologists have not crossed the chasm between the geophysical and engineering realms and microseismic processing remains in its infancy.

The primary motivation behind this microseismic monitoring project was to test completions methods. The program was designed to vary injection rates and proppant concentrations and the microseismic was to map the resulting fractures. However, during processing of the data it became apparent that there was much uncertainty in the final product and Hess therefore embarked on an effort to process the data by 3 different companies to help identify the magnitude of uncertainty.

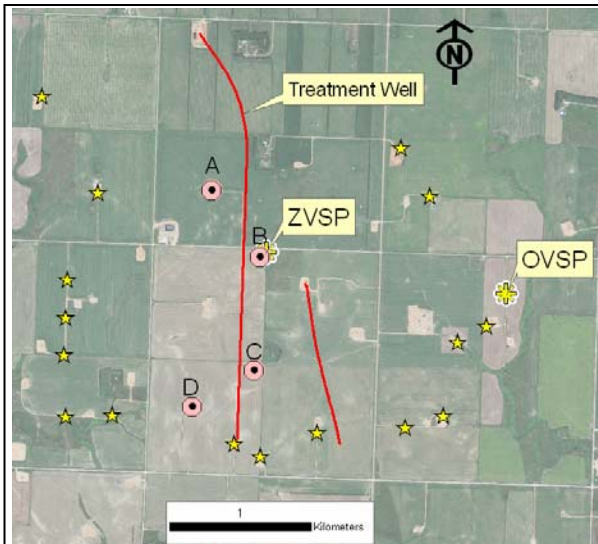

Figure 1a. Field design for microseismic project. Wells labeled A, B, C, and D are microseismic monitor wells. Yellow stars are walk-around VSP source points. Well B is location of zero-offset VSP, and the offset VSP source is indicated by an asterisk. Three stringshots were used for calibration and orientation: Well A, detected by wells B and D; Well C detected by well D; and well D, detected by wells A and C. There were 18 geophones in each well, except for well B which had 17.

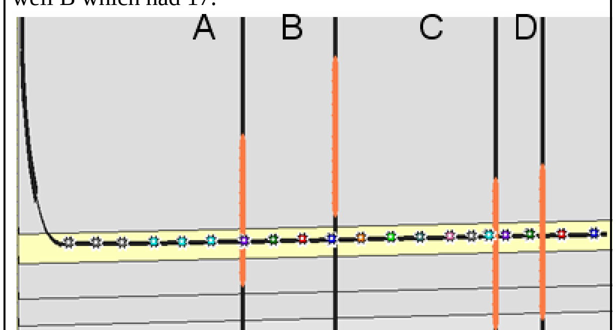

Figure 1b. Cross sectional view of the geophone geometry. Orange indicates geophones, colored stars represent stages. The lateral is drilled within the Middle Bakken (in yellow).

Comparison of Three Microseismic Results

Project Definition

The treatment was in a 3,050 m Bakken horizontal well that lies in the Beaver Lodge area on the Nesson Anticline (fig. 1). Two producing wells and two injection wells were used as monitors with 18 geophones straddling the Bakken in all wells except B, where the bottom five were damaged by heat (originally this VSP well contained 22 geophones). The entire array in the northernmost well was also damaged, but it was pulled and replaced halfway through the experiment. Since the well was completed with sliding sleeves, the following string shots had to be acquired for geophone orientation and velocity model calibraton:

1) Source in well A, detected in wells B and D prior to fraccing.
2) Source in well C, detected in well D prior to fraccing.
3) Source in well D, detected in wells A and C after fraccing.

Permit problems resulted in a depopulated source array and a non-uniform radius for the walk-around VSP, making HTI estimation challenging. Ultimately, a zero-offset VSP was acquired pre-frac but the array did not extend through the Bakken due to the damaged geophones. A post-frac walk-around VSP was acquired as well as an offset VSP from a lateral distance of 1755 m.

Processing

The microseismic data was processed by three different companies who had different approaches to solving the same problem.

Company 1 had a single well solution where the closest well to the event was used for event location. The logic was that wells at a greater distance had greater uncertainty and would introduce more error into the solution. Using traditional P-S wave picking and hodogram analysis they saw significant variation in location given by different wells, probably due to anisotropy in the area. However, their velocity model consisted of one shear and one compressional sonic log, adding some tilt to conform to local dip. They calibrated the velocity model using string shots, ball setting events, and at times assumed the first large event was located near the wellbore.

Company 2 tried the single well solution approach, but said the data was noisy and lacked P-waves. Their first attempt saw abnormal clustering of events and this procedure was abandoned. The second approach was to generate two velocity models using shear sonic logs: one to the north and one to the south, each incorporating the two closest wells. They then picked only S-wave events detected in two wells and used triangulation plus hodograms to determine the location.

Company 3 incorporated string shots, well logs, VSP information, and horizons into a 3D anisotropic velocity model. They emphasized that a longer array would have been preferred and they used the traditional P-S wave picking plus hodograms for event location.

Each company above uses different event picking and ray-tracing algorithms along with its own unique set of criteria for picking events. Although some similarities can be found, and some conclusions drawn, the final results show a high degree of variation between the three solutions.

Comparison of Results

A map and cross-sectional view of the results (fig. 2) shows the variation found from one contractor to the next. Viewing a movie of the events over time is the best way to interpret microseismic data and reveals the following about each company's result:

Company 1: Events in this version behave just as the asset team expected. Each stage is present with the events appearing near its injection point. There are very few events in the Three Forks formation directly below, the fractures grow upward into the overlying Lodgepole, and lateral fractures are asymmetrical. This version showed high magnitude events occurring two hours before stage one as well as high magnitude events a significant distance east of the wellbore belonging to stage 8. A possible fracture zone is interpreted above stage 6 where a slight structure is seen in surface seismic and events go higher than the rest.

Company 2: This version contains fewer events and its locations/timing differs significantly from the other two. The fracs grew up half as high, but went down twice as far as Company 1. Lateral growth was 80% of Company 1 to the west and 60% to the east. It's fractures are asymmetrical, and events from stage 9 are seen to the northwest a significant distance away. It also shows a possible fracture zone above stages 5 and 6, similar to Company 1. There may be a small northeast-southwest trending "fracture plane" between the two northern wells that is similar to one seen by Company 1. This version has no events located for stages 3, 4, and 16.

Company 3: This version has events fraccing down into the Three Forks an average of 5.5 times as far as Company 1 and growing up on average 0.8 times. Whereas Company 1 shows fractures growing higher prior to stage 8 and lower in section after that, this version shows the opposite, with fractures deeper in the toe and growing up after stage 10.

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Perhaps most striking in this version is the presence of events from almost all stages (including stage 1) occurring near the northern two wells, eventually forming a trend that follows a positive curvature anomaly. Most of the events to the north are low magnitude events. The early events surrounding well A up through 2:30 pm may have been caused by noise from changing the damaged array in that well.

After seeing the above differences in event location from three different vendors, the need to narrow in on the most correct answer becomes obvious. Each version was compared to seismic attributes to test for conformance to surface and reservoir features. Company 3 does show a better qualitative match between event location and positive curvature (fig. 2) and it also shows interesting relationships between event density and facies (fig 3).

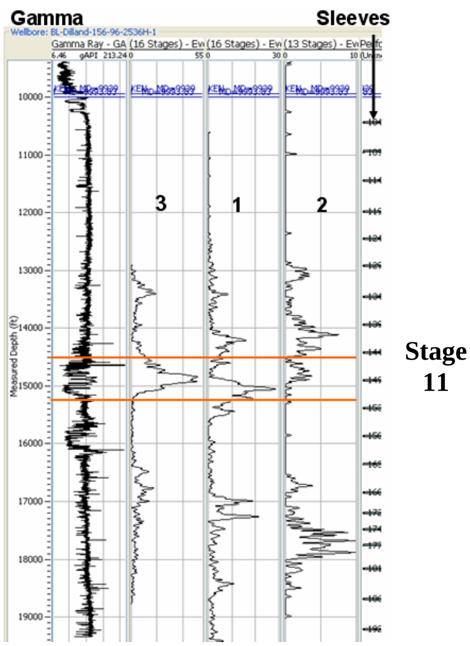

Figure 3. Horizontal Gamma log with well toe at the bottom. Logs 1, 2, and 3 are event density logs for the different versions. Orange lines straddle stage 11, where Company 3 shows high event density at the lower Gamma. Stage 9 shows this same low Gamma, but a fracture zone may preclude events.

The MWD Gamma shows intersection with a lower Gamma unit at both stages 9 and 11. Company 3 shows an increase in event density around stage 11, though none for stage 9. However, this lack of events can be explained by the regional NW-SE fracture zone that can be interpreted through stage 9 and bisects the well into two stress regimes.

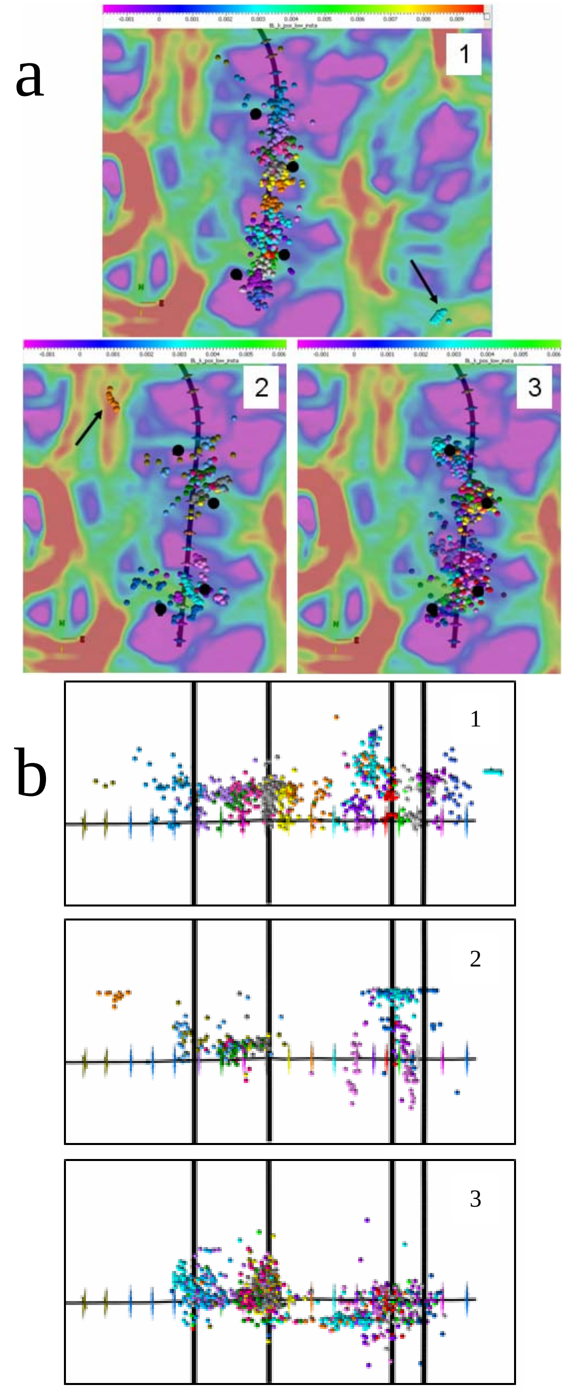

Figure 2a and 2b. Map (a) and cross-sectional (b) views of microseismic from companies 1, 2, and 3 with long wavelength positive curvature map (a) and rfc seismic (b). Only events with error less that 76 m shown for company 3. The other companies did not provide this same criteria so all their events are shown regardless of uncertainty. Events colored by stage. Arrows show anomalous events.

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This separation of the events into two regions is seen on all three datasets and on a regional structure map (not shown in this abstract). The fault may be draining the frac energy and preventing events in this area.

Some correlations have been found when comparing to completion data, but there was no obvious relationship between injection rate and event count for any of the versions.

Completions parameters, facies, and the presence of a fault are most likely controlling the stress and event count to some extent, but the degree of each must be studied in greater detail before predictions can be made for other wells.

The calculated Stimulated Reservoir Volume (SRV) for each version (fig. 4) shows very different geometries and volumes. SRV is just beginning to be linked to discrete fracture networks to give us a better understanding of how unconventional reservoirs behave. All three versions here show that fractures are neither bi-wing nor symmetrical as current models assume, thus we carry uncertainty in our predictions of well performance and reserves. It will be essential in the future to define propped reservoir using SRV geometry, and event density may indicate a higher degree of induced porosity.

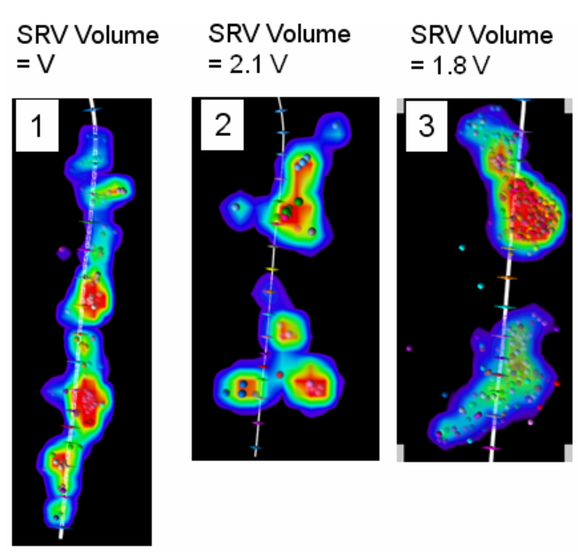

Figure 2b. Stimulated Reservoir Volume for three companies with microseismic events within Bakken only shown. Events colored by stage.

Conclusions

Three companies have processed the same microseismic dataset and have come up with varied results. Experience with other Hess microseismic surveys has suggested the Bakken may be a quieter microseismic area than other unconventional plays, so the same study in another area could show more consistent results. Different velocity models and lack of perf shots for calibration and geophone orientation most likely caused much of the ambiguity. Surface vibes would have helped orient the geophones better, especially the northern well which only detected one string shot from 2134 meters. However, the variation in event numbers between the companies shows individual exclusion criteria and picking algorithms also contribute. Due to the fact that fractures are the target of investigation, 3D anisotropic velocity models should be used, as they cause anisotropy themselves. VSP surveys before and after fracturing can confirm how velocity changes through the fracturing process, and results can be incorporated into velocity models for event location.

Oil and gas companies have consistently considered microseismic results accurate, and often change the frac program accordingly in real time. However more work is required and more comparisons made before we can approach a true understanding of how fracturing occurs in the subsurface. We can look towards seismology for a wealth of knowledge regarding earthquake event location, and we should expect a higher degree of accuracy as this fledgling technology progresses.

Acknowledgements

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EDITED REFERENCES

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REFERENCES

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