Assessing the effectiveness of hydraulic fractures with microseismicity

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Summary

Passive seismic imaging is used to map the development of hydraulic fractures in relatively non-fractured and naturally fractured reservoirs. The images obtained for multiple stimulations throughout the U.S. identified non-complex preferential fracture growth patterns with constrained permeability enhanced pathways, lithologically controlled symmetric and asymmetric hydraulic fractures, and complex fracture patterns associated with fluid-flow along pre-existing fault networks. In this paper, we examine these observations in the context of establishing effective field drainage through optimal well placement.

Introduction

Having a reliable method to directly measure hydraulic fracture geometry / orientation and assess the quality of the created fractures as permeable pathways allows stimulation engineers to improve completion designs and develop strategies for effective drainage of oil and gas reservoirs. Typically, parameters such as surface pressure and injected volumes are used for real-time control of the stimulation. This is sometimes augmented with surface and downhole tiltmeters that provide relative fracture orientation and length data, but do not provide full images of the fracture volume. History matches of numerical model simulations, post-frac radioactive-tracer tests and production results are also used to assess the success or failure of hydraulic fracture based stimulations. This approach, however, is constrained by model limitations which assume fracturing occurs symmetrically about the treatment well.

In recent years, it has been suggested that passive seismic monitoring offers an opportunity to image the dimensions of hydraulic fractures by evaluating the distribution of microearthquake locations and their source characteristics (e.g., Urbancic, 1998, 1999) in both space and time (e.g., Maxwell et al., 2000). In this paper, we carry out a general assessment of the microseismic response for stimulations monitored over the past few years in the U.S.. Consideration is given to the spatial and temporal variations in microseismicity as related to fracture growth, fracture symmetry and the development of enhanced permeable pathways in faulted reservoirs. Questions concerning the recording of microseismicity, its relationship to predicted fracture lengths, and establishing effective field drainage are discussed.

Data Collection

Microsiesmic images obtained from over 20 stimulations are examined in this presentation. These include water and gel based hydraulic fractures in tight gas sands and shales. In all cases, monitoring was carried out from a single well, with an 8 to 12 level retrievable array of triaxial geophones located above the reservoir within close proximity to the treatment well. Prior to each stimulation, the array of geophones was clamped in place. Perforation shots in the treatment well were recorded and used to determine the orientation of the individual geophone sondes. Signals were continuously monitored and a complex trigger logic was employed to discern events from background noise in real-time. Figure 1 shows an example of the recorded signals along with the automated P- and S-wave arrival times. The events were automatically located based on arrival times and azimuths (orientation to the event source), as shown in Figure 2, and their source characteristics determined (corrected for attenuation). Visual images of the stimulation were obtained in real-time and combined with engineering data (2-D fracture mechanics model output and stimulation parameters such as surface pressure and proppant concentration; e.g., Figure 3). The real-time analysis, in a number of cases presented, allowed the well completion engineers the opportunity to modify their stimulation procedures during the treatment.

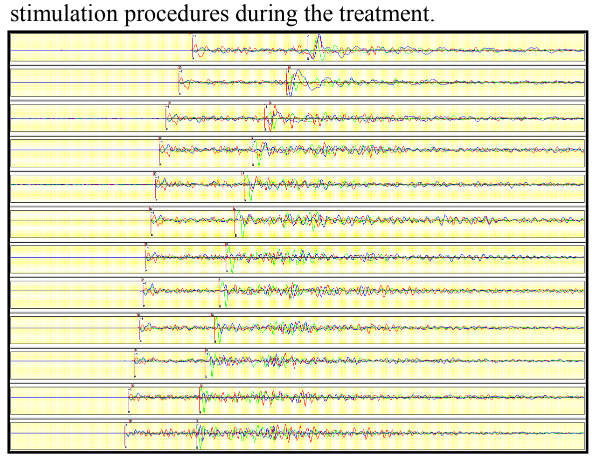

Figure 1. Triaxial sonde waveforms with each component of the triaxial superimposed. Top to bottom corresponds to the shallowest to deepest levels.

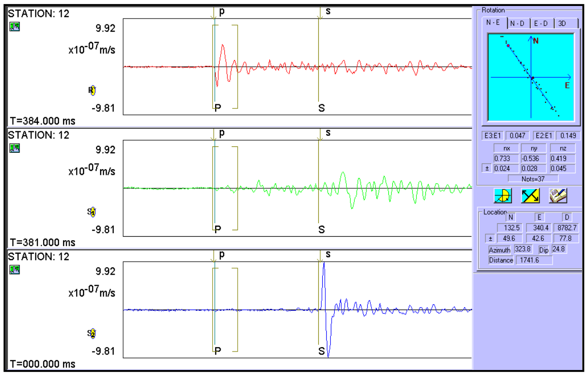

Figure 2. Hodogram analysis of a triaxial signal. The amplitudes of the different components are used to determine the azimuth to the source (upper right window).

Microseismic Images

In Figures 3 and 4, microseismic events, ranging in magnitude from $-2.7 \leq M \leq -0.2$, for four different treatments are shown along with the surface pressure, proppant concentration, and event distribution as a function of time. As observed, the microseismic response for each treatment varies from one treatment to the next, regardless of monitoring well position. In all cases, treatment, resulted in a significant growth of the fracture away from the treatment well. Overall, the events, which represent individual failures with a set orientation and length, define a relatively non-complex grouping of fractures with well defined overall hydraulic fracture orientations. The asymmetric growth in Figure 3 is inconsistent with fracture model predicted symmetric fracture heights and lengths, suggesting that either the model employed is not adequate for this application.

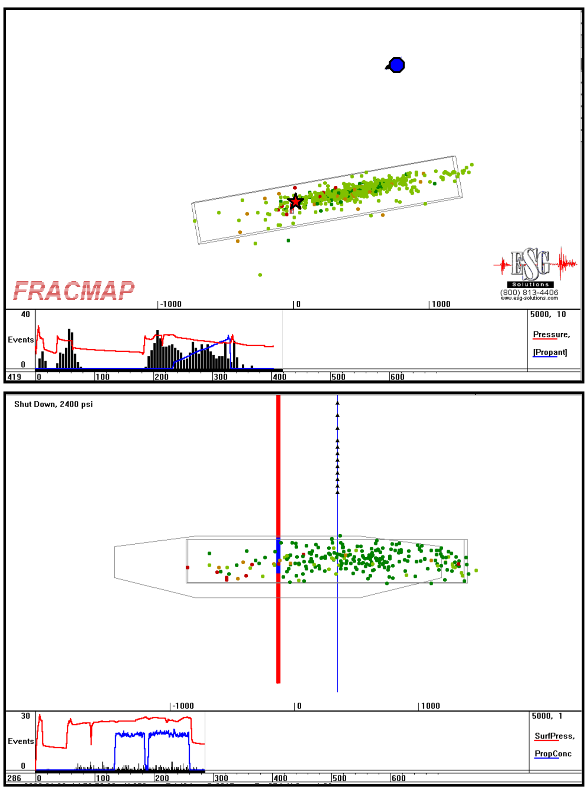

Figure 3. Microseismicity scaled by magnitude for two stimulations in plan and longitudinal and normal to the fracture views. Both the treatment (star) and monitoring (circle) wells are as shown. Magnitudes range from –2.7 (green) to –0.2 (red).

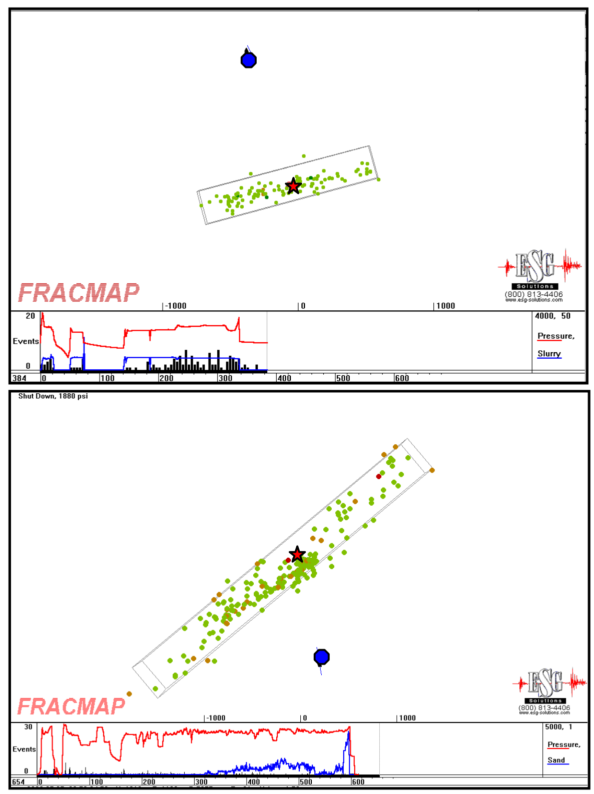

Figure 4. Additional microseismic images in plan view of stimulations scaled by magnitude. Symbols are as indicated in Figure 3.

Hydraulic fractures effectiveness

Image Robustness

To consider if the asymmetric response was influenced by the recording geometry (use of one monitoring well), a comparison was made between stimulations monitored in the same field (Figure 5). In each case, the strike of the main fracture was calculated by linear regression, and the angle between its normal and the monitoring well relative to the treatment was determined. As shown in Figure 5, the monitoring angle to the fracture varies by over 50 degrees. The degree of symmetry generally falls into three categories, 1 to 1, 2 to 1, >2 to 1 (in the last case, the higher asymmetry may be related to data quality issues). Upon closer examination of the data, the variations can be related to treatments in different lithologic layers, suggesting that the recording geometry did not influence the outcome and that the observed distributions in microseismic values are representative of the fracture growth behavior occurring in the field. By further defining a minimum recordable magnitude range over the distances monitored, the degree of recording asymmetry can be identified and corrections to the images applied (see Maxwell et al., 2002), such as the case in the examples provided.

Therefore, we can suggest that the presence of geological structures and other depositional permeability barriers with directionality within different lithologic units affect fracture growth, and on a larger scale, the overall hydraulic fracture orientations and degree of symmetry. An alternative explanation for the observed asymmetry is the timing of proppant and pressures used in the injections.

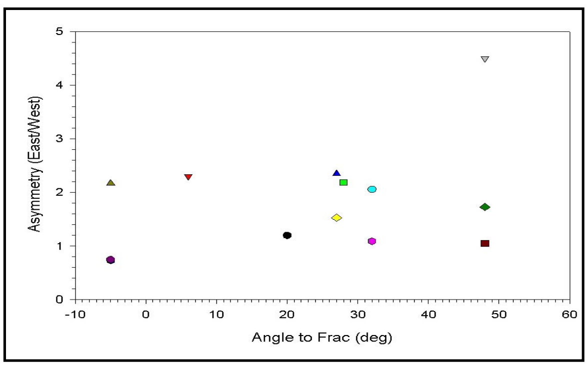

Figure 5. Relative asymmetry for 12 treatments in Texas. Fracture Symmetry appears to be controlled by the lithology. Treatments were in three lithologic zones corresponding to East wing / West wing symmetries of 1:1, 2:1, > 2:1 (data quality at issue in last case).

Fractured Reservoirs

The hydraulic fractures created can be well behaved and follow predicted orientations, as seen in Figures 3 and 4, or be widely dispersed as observed in Figure 6. In this case, the dispersion in microseismic response suggests that the treatments were influenced by the underlying natural fracture system in the reservoir, where the microseismicity trends SW to NE and NW to SE, similar to the orientation of the faults. In time, the treatment in Figure 6 initiates a hydraulic fracture in a NE direction, as expected from local stress and lithologic conditions, however, after a short period of time, the flow appears to be re-directed along a NW to SE cross-cutting fault which further re-directs proppant fluids to nearby parallel SW to NE faults. As such, the observed variability in microseismic response, suggests that treatment procedures can be modified when the treatment does not appear to adhere to hydraulic fracture design criteria, and that proper well placement is dependent on being able to effectively map the variable drainage associated with each treatment.

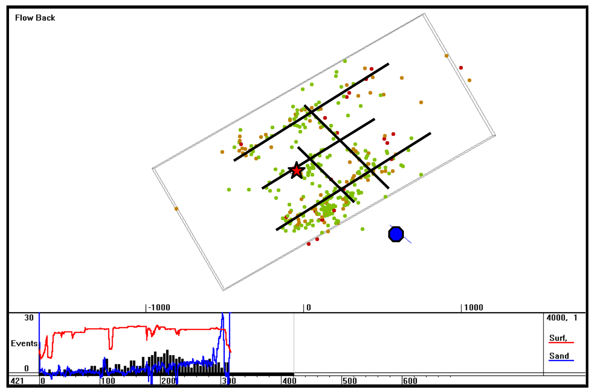

Figure 6. Plan view of simple treatment in a naturally faulted reservoir with microseismic events scaled by magnitude values. Low magnitude events are shown in green whereas larger values are shown in red. The treatment well is in red (star) along with the monitoring well in blue. Magnitude values range from -2.6 (dark green) to –1.1 (red).

Implications

Microseismic images offer an opportunity to improve stimulation procedures not only in real-time in the field, but in the design of individual stimulations and reservoir drainage programs. Stimulation engineers typically rely on simplified physical models to simulate the fracturing, which forms the basis of the hydraulic fracturing design.

Hydraulic fractures effectiveness

The vast majority of models assume a fracture growing symmetrically outwards from the frac well either in two or three dimensions. As shown by microseismic imaging, this may not always be the case. Differences in growth characteristics and symmetry require a re-assessment of design strategies, particularly in the context of actual fracture complexities. On a wider reservoir scale, the implications of individual well stimulations can have a dramatic effect on the overall production expectations. Typical well patterns assume simple, theoretical fracture geometries to maximize drainage (Figure 7). However asymmetric fracture growth, or growth in a direction different to that assumed, such as in the case of heterogeneous fracture patterns, can significantly alter the drainage. Under these conditions, microseismic imaging can play a significant role in identifying poor drainage, wetting out conditions, and pockets of remaining product and potentially contribute to improving field drainage.

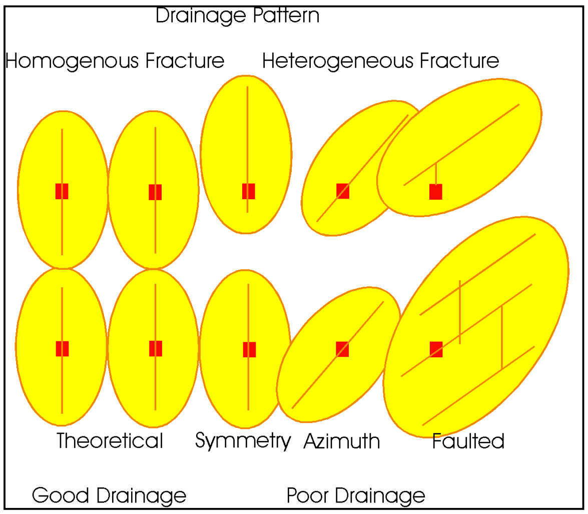

Figure 7. Example how fracture geometry can influence field drainage. Gaps in drainage are possible when issues of symmetry and faulted reservoirs are not considered.

Conclusions

In this paper, we have shown that microseismic imaging can be used to enhance our understanding of the hydraulic fracture process. The observations indicate that microseismic events provide robust information on the dimensions and orientations of hydraulic fractures, their growth characteristics, and a method of identifying constrained permeability enhanced pathways, lithologically controlled symmetric and asymmetric hydraulic fractures, and complex fracture patterns associated with fluid-flow along pre-existing fault networks. Our observations also raise questions about the effectiveness of fracture mechanics models to account for issues of preferential fracture growth, fracture symmetry versus asymmetry, and the role of constrained permeability enhanced pathways versus fluid-flow along pre-existing fault networks in maximizing reservoir drainage. Generally, microseismic imaging provides a robust approach towards establishing different levels of hydraulic fracture complexity in the reservoir and potentially contributes to improving well placement and field drainage..

References

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