Passive Seismic Imaging of Hydraulic Fractures

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Passive seismic monitoring can potentially be used in a number of reservoir monitoring applications, including fault mapping, water/gas injection imaging, casing deformation and imaging the thermal front in heavy oil recovery. In this paper, the application of imaging hydraulic fractures during well stimulation is presented along with discussion of the potential impact on reservoir engineering. Hydraulic fracturing is a wide spread technique to stimulate flow and increase production in many fields, which can be more effectively designed using microseismic images of the true fracture geometry.

In March 2000, passive monitoring of a hydraulic fracture was performed for PanCanadian in Western Alberta. A 12 level, 210 m aperture, wireline geophone array was deployed in a well approximately 600 m away from the well being stimulated. During the injection, continuous seismic data was relayed from the array into a passive seismic acquisition system. Event detection was performed to identify microseismic events, which were archived to a computer where the data was automatically processed. The passive seismic data was intergrated with engineering data including injection presssures, volumes, rates etc, providing the engineers with a continuous realtime image of the hydraulic fracture growth (Maxwell et al, 2000).

Figure 1 shows a longitudinal view of the microseismic image from the first part of the treatment, and Figure 2 shows the image from the end of the treatment. The visualizer allows the image to be viewed from any direction and played back in time, and the event symbols can be displayed as either seismic attributes (such as magnitude) or engineering parameters (such as pressure at the time of the seismic event). In this way, the images can be used to image the orientation of fracture growth, determine if the fracture is contained within the target volume or growing outwards, the length of the fracture and fracture complexities such as the interaction with pre-existing fractures. For example, comparing Figures 1 and 2, the fracture can be seen to be initially contained within the target reservoir interval. With time the fracture grows preferentially in one direction and eventually grows upward out of formation.

Beyond determining the fracture height and length as shown with the figures, the images can also be used to determine the azimuth of the fracture. In some cases, such as naturally fractured reservoirs, hydraulic fracturing has been found to result in complex fracture growth as the stimulated fracture reacts with the pre-existing fracture network. Microseismic data can also be used to assess not only the location of the fracturing, but also fracturing mechanisms through the investigation of seismic source attributes (e.g. Urbancic and Zinno 1998). These attributes can be used to assess the overall effectiveness of the hydraulic fractures to increase permeability.

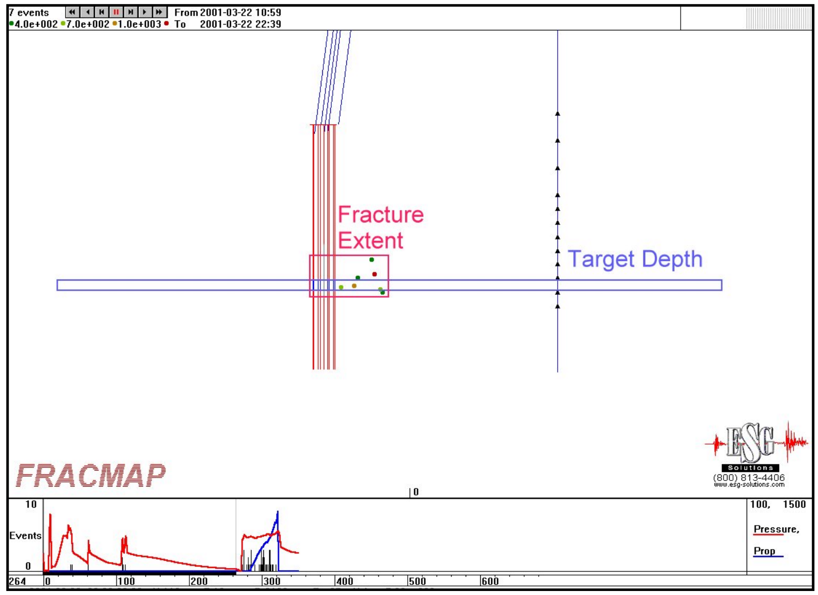


Figure 1. Longitudinal view of the hydraulic fracture image, showing frac well in red, monitoring well in blue, and geophone locations as black triangles. Events recorded at start of frac are colour coded by injection pressure.

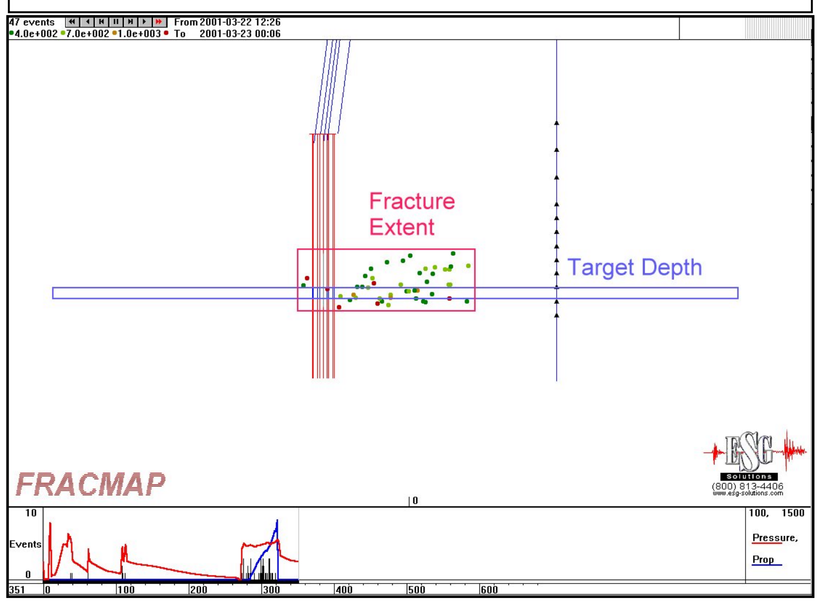


Figure 2. Longitudinal view of events recorded to the end of the frac.

Microseismic images can be used in a number of ways to improve the stimulation engineering in the field, beyond basing real time operation decisions on the latest images as the stimulation proceeds. Firstly, a series of unique fracturing operations can be tested using the microseismic imaging, such as the fracturing of various depth intervals simultaneously or the restimulation of older production wells. The fracture images can also used to calibrate numerical simulations of the fracture dimensions. Typically, engineers rely on simplified physical models to simulate the fracturing, which forms the basis of the hydraulic fracturing design. For example, the vast majority of models assume a fracture growing symmetrically outwards from the frac well. As shown above this may not be the reality, resulting in design strategy that needs to be reconsidered in context of the actual fracture complexities. Furthermore, the computer simulations require the input of numerous parameters, which can be more confidently calibrated if additional information such as fracture dimensions are available. The dimensions of the fractures indicated from the microseismic monitoring can be used to match the simulated dimensions in order to calibrate the modeling parameters. Figure 3 shows a generic illustration of the calibration for a fracture model. A fracture imaging project could involve a number of wells with different pump rates, volumes, pressures and times, in order to optimize the stimulation design to a target fracture length. This target length can either be related to the specific well spacing in the field, or optimized by linking a calibrated numerical simulator with production forecasts. This could be used to determine the fracture length that maximizes the net present value of the well by trading off stimulation costs against estimated production rates.

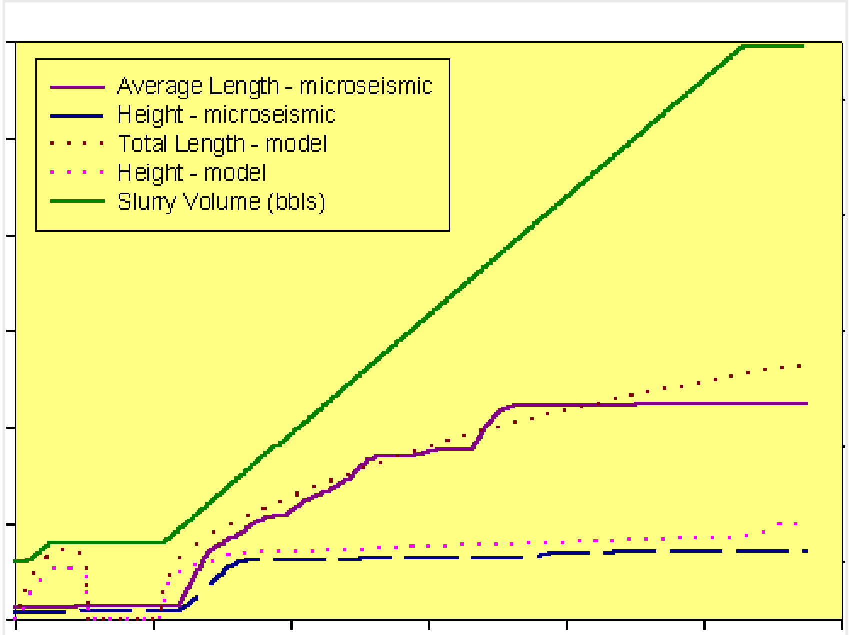
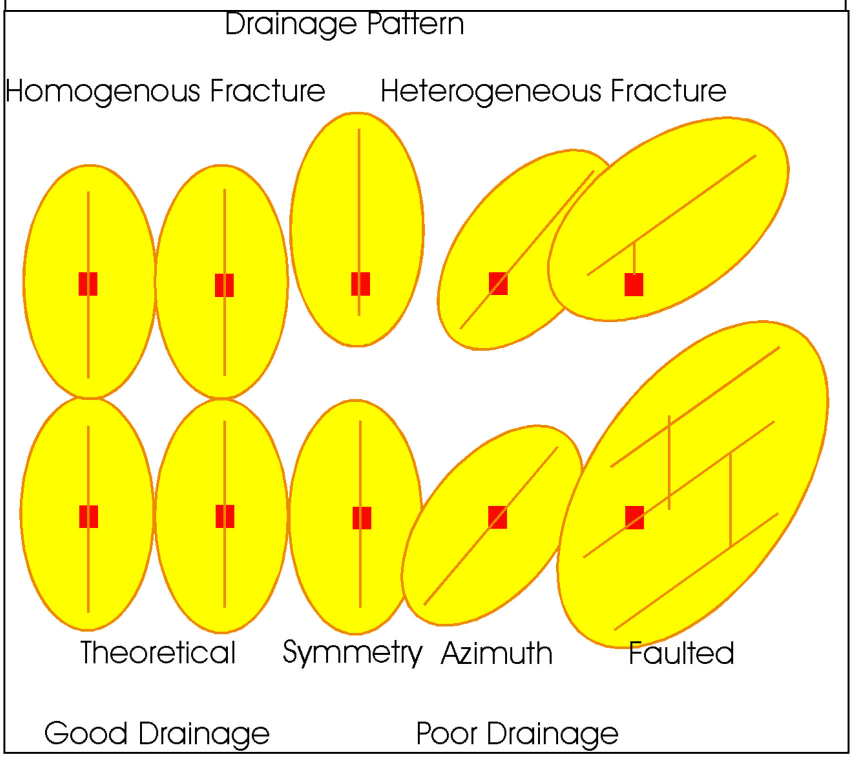


Figure 3. Example of calibrating simulated fracture dimensions with microseismic data.



Finally heterogeneous fracture patterns can be used to improve field drainage, as shown in Figure 4. Typical well patterns assume simple, theoretical fracture geometries to maximize drainage. However asymmetric fracture growth, or growth in a direction different to that assumed can significantly alter the drainage. Furthermore, interaction with pre-existing faults can also alter drainage, especially in the case of horizontal wells.

References

Maxwell, S.C., Urbancic, T.I., S.D. Falls and Zinno, R., Real-Time Microseismic Mapping of Hydraulic Fractures in Carthage, Texas, Annual Meeting SEG, 2000.

Urbancic, T. I., and Zinno, R. J., Cotton Valley Hydraulic Fracture Imaging Project: Feasibility of determining fracture behavior using microseismic event locations and source parameters, Annual Meeting SEG, 1998.