Integration of Surface Seismic, 3D VSP, and Microseismic Hydraulic Fracture Mapping to Improve Gas Production in a Tight Complex Reservoir

Nancy House, EnCana Oil and Gas (USA) Inc., Brian Fuller, Sterling Seismic Services, Julie Shemeta, Pinnacle Technologies, Inc., Marc Sterling, Sterling Seismic Services.

Summary

Completion techniques in tight hydrocarbon reservoirs typically include hydraulic fracturing to increase permeability. In this study surface seismic data, 3D VSP data, and microseismic mapping of induced hydraulic fractures were combined to understand the magnitude, direction, mechanisms, and lithologic controls on hydraulic fracturing in a tight gas reservoir. Fracture points were mapped from 3D surface seismic data, VSP data were used to tie borehole measurements to the surface seismic volumes, and 3D VSPs and offset VSPs were used to increase resolution and determine specific influences of reservoir zones or faults on the direction and magnitude of the fractures. Detailed velocity information obtained from multi-level multi-component VSP data (measured with the same instruments as the microseismic events) provided accurate locations of the measured fracture events in addition to providing well-constrained ties to the surface seismic volumes. Integration between disciplines improved the reliability of all of the data and provided the interpreter a unique opportunity to 'see' where the induced fractures occurred, thus highlighting fluid pathways within the complicated reservoir. These insights significantly improved design and implementation of hydraulic fractures. The integration methodology can be applied in other settings and projects.

Introduction

Tight formations hold vast reserves of hydrocarbon around the world. Aggressive completion techniques including multi-stage hydraulic fracture treatments are used to make the tight reservoirs economic. The ability to dynamically map hydraulic fractures with microseisms has become a powerful tool for engineers to understand the growth and geometry of induced fractures. We discuss the combination of passive seismic mapping with conventional surface seismic and newly developed techniques for VSP data processing. These data allow the integration of geophysical, geological and engineering data to aid in the interpretation of important reservoir properties. The microseismic and VSP data can be collected with the same set of borehole tools.

Vertical Seismic Profile Data (VSP)

Three different types of VSP data were incorporated into this work, 3D VSP, Single-offset VSPs, and zero-offset VSPs. Each of the VSP types and their contribution to the project is discussed below.

3D VSP

In a 3D VSP seismic receivers are placed in a borehole and hundreds of seismic source points are placed within some radius of the receiver well and distributed at all azimuths. Images obtained from the datasets in this project contain more than twice the frequency content of the surface seismic data and were used in interpretation to extract structural details of faults and to understand stratigraphic relationships. The source points were laid out along existing roads and on well pads to comply with environmental restrictions and were not on a regular grid. The 3D VSP data in this study were collected with a 12 level, 3-component geophone array. The array is configured with approximately 37 feet between levels, for a total tool length of 440 feet. The geophones are Oyo Geospace DDS-250 3-component receivers with 24-bit digitization in each tool. The 24-bit data is telemetered to the surface with a fiber-optic wireline at variable sample rates. We used 1 millisecond for the 3D VSP and ¼ millisecond for the microseismic recording.

Single-offset VSP

In a single-offset VSP seismic receivers are placed in a borehole and a single seismic source point is placed at some horizontal offset from the receivers. Most often for the datasets discussed in this paper the source-receiver horizontal offsets were approximately 1/2 to 2/3 the depth of the target. Single offset VSPs that have sufficient signal-to-noise ratio can be used to obtain a 2D reflection profile between the receiver well and the seismic source point. The 2D image profile generated by a single offset VSP is analogous to the image created by applying Normal Moveout (NMO) to a single 2D surface seismic shot record. If the signal-to-noise ratio is high and the NMO function is close to correct then the result will be a single-fold 2D reflection profile of the earth.

Integration of Surface Seismic, 3D VSP, and Microseismic Hydraulic Fracture Mapping to Improve Gas Production in a Tight Complex Reservoir

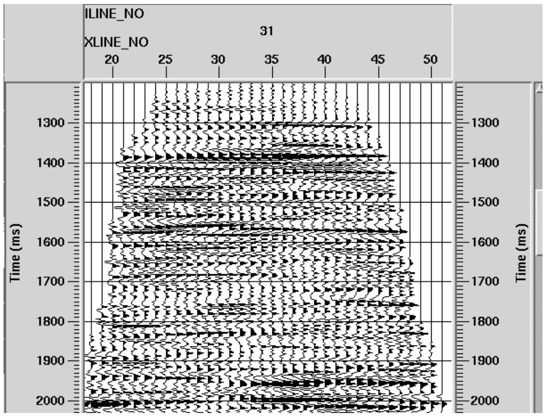

Figure 1. Vertical slice from full 3D VSP volume used in this study. Frequency content in the stacked image exceeded 140 Hz.

Zero-offset VSP

In a zero-offset VSP seismic receivers are placed in a near-vertical borehole and the seismic source is placed near the wellhead. Most of the seismic energy that is recorded is from vertically traveling waves. Zero-offset VSP data is particularly good for obtaining interval velocities, time-depth relations, and for determining the phase and travel time of primary reflections at seismic frequencies. P-wave and S-wave velocities measured in the zero-offset VSP can be used to verify velocities measured in perforation shots that are subsequently used in processing microseismic events.

VSP Processing

All VSP data in this paper were processed using all three receiver components. Multi-component processing is required for offset and 3D VSP processing in particular because the upgoing reflection ray paths are generally at oblique angles to the borehole, thus all three geophone components must be used to capture the entire reflected wavefield. Multiple components must be used even for zero-offset VSP data processing. Horizontal components are used in zero-offset processing to measure direct S-wave velocities and to deal with geophone tilting that occurs in deviated boreholes. Additionally all three components are needed to recognize and remove reflections from steeply dipping features that are near the receiver borehole and create events with very large apparent velocities. Offset and 3D VSP datasets were processed using time domain methods. Particular attention is paid to velocity analysis and statics analysis, which are as important in VSP imaging as they are in surface seismic imaging. One advantage of time domain processing is that the resulting images can be directly integrated into the interpretation framework that is used in the overwhelming majority of interpretation work. Figure 1 shows a vertical slice though one of the 3D VSP volumes used in this study.

Microseismic

As a hydraulic fracture is pumped into a formation, changes in pressure and stress take place (Warpinski, et al., 2001). These changes cause small slippages to occur along preexisting fractures in the formation. These shear failures create P- and S-waves, which can be detected at seismic receivers (Figure 2, Albright and Pearson, 1982). Because microseism amplitudes are small, sensitive tools and small recording distances must be employed.

Data acquisition

Starting just before the hydraulic fracture, 24-bit data

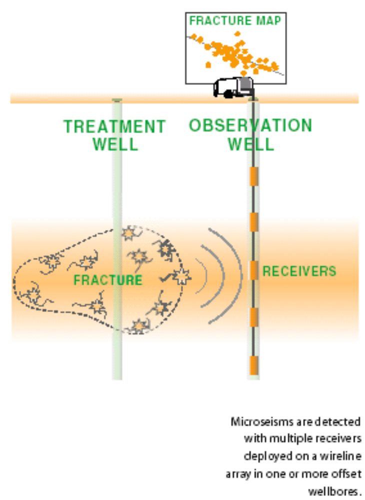

Figure 2. Microseismicity is recorded in an observation well during a hydraulic fracture treatment.

recorded from the 12 level geophone tool string is telemetered to the surface with a fiber-optic wireline at ¼ millisecond sample rate. The frequency of microseismic data is typically greater than 1000 Hz; the fiber-optic wireline allows a high sampling rate and a multi-level tool. The seismic data is continuously recorded at the surface during the fracture treatment and for several hours after, until the level of induced seismicity drops. A signal to noise ratio filter is run on the continuous data to extract the individual microearthquakes.

The microseism locations are computed using the P- and S-wave times to calculate the height and distance, and the particle motion of the P-wave calculated from a hodogram is used to compute the direction of the event. The receiver array is oriented using perforation shots in the treatment well bore to obtain the correct geophone orientation for the hodograms.

For this study, the observation well bore with the tool string, is located within 500 to 1000 ft from the treatment wells, and is unperforated, cased and cemented well. The geophone array is placed at a depth in the monitor well to straddle the perforated zone in the treatment well for the planned hydraulic fracture (Figure 2).

Figure 3 is an example of microseismic data collected from a tight gas sand during a hydraulic fracture treatment. The locations of the events show a preferential azimuth and height within the formation. These locations combined with the 3D VSP volume allow detailed resolution of each stage of a hydraulic fracture treatment and accurate planning for subsequent stimulation.

Conclusions

Detailed understanding of reservoir architecture is essential for execution of hydraulic fracture programs that maximize the value of reserves in tight gas reservoirs. High frequency information obtained from hydraulic fracture monitoring and VSP data resulted in improved understanding of the reservoir and increased the probability of improved production in continued reservoir development. The high frequency data also enhanced the value of existing 3D surface seismic data by providing local details observed in the lower-frequency 3D surface seismic data but which covers a large area.

References

Albright, J.N. and Pearson, C.F., Acoustic Emissions as a Tool for Hydraulic Fracture Location: Experience at the Fenton Hill Hot Dry Rock Site, SPEJ 22 (Aug. 1982), 523.

Warpinski, N.R., S.L. Wolhart; C.A. Wright, Analysis and Prediction of Microseismicity Induced by Hydraulic Fracturing; paper number SPE 71648, presented at 2001 SPE Annual Technical Conference and Exhibition, New Orleans, LA, 30 September- 3 October, 2001.

Acknowledgements

We thank EnCana Oil and Gas for permission to publish this work. We are indebted to EnCana's Dean Dubois, Tom Hewett, Cally McKee, Jeff Johnson, and Mark Turner for their support in implementing this project. We are grateful to Angus Duthie, Frank Melendez, Charlie Waltman, Sean Machovoe, John Alcott, Scott Malone and Trent Green of Pinnacle Technologies and Bill Schorger of Sterling Seismic Services for their contributions to this project.

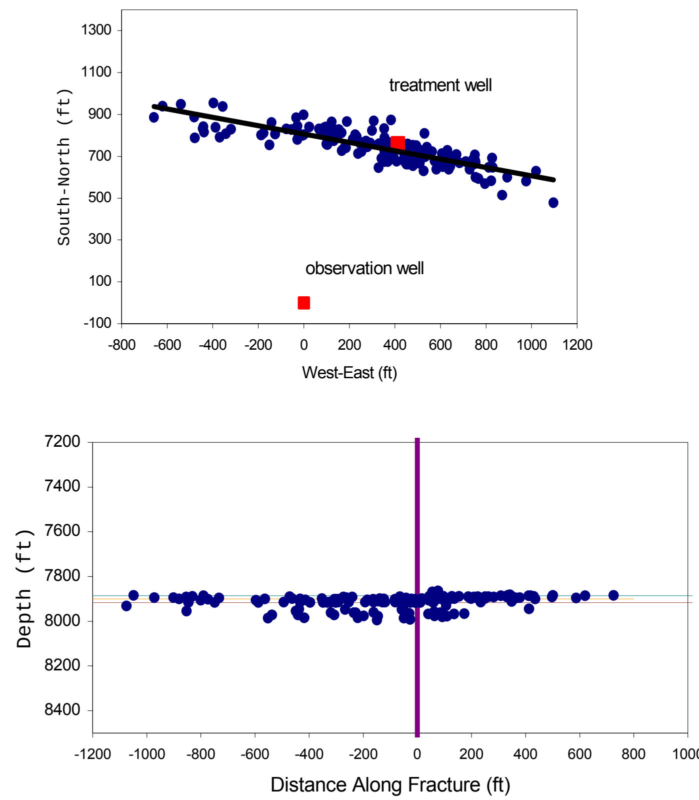

Figure 3. Map and cross section views of microseismic data located during a hydraulic fracture in a tight gas sand. The blue dots show the locations of the microseismic events. The upper figure is a map view; the solid line shows the interpreted fracture azimuth. Lower plot is a cross section of the microseismic data shown parallel the fracture azimuth shown in map view, the horizontal lines show the location of the perforated interval, the vertical line represents the location of the treatment well.