Demystifying Tight-Gas Reservoirs using Multi-Scale Seismic Data*

Murray Roth[1], Tom Davis[2], and Julie Shemeta[3]

Search and Discovery Article #80437 (2015)
Posted February 9, 2015

*Adapted from extended abstract prepared in conjunction with a presentation given at CSPG/CSEG 2007 GeoConvention, Calgary, AB, Canada, May 14-17, 2007,
CSPG/CSEG/Datapages © 2015

[1]Transform Software and Services Inc., Littleton, CO, United States (murray@transformsw.com)
[2]Colorado School of Mines, Golden, CO, United States
[3]Pinnacle Technologies, Centennial, CO, United States

Abstract

Low permeability sand and shale reservoirs in the US Rocky Mountain region are estimated to hold nearly 7000 tcf of gas reserves (DOE 2003). In a typical reservoir, hundreds or thousands of feet of stacked fluvial sands are gas charged, with natural and induced fractures being essential for economic gas production. While seismic data is useful for identifying major geologic interfaces and faults, the thin and complex nature of these channel sands are typically below seismic resolution confounding interpretation at the reservoir level. Well planning optimization generally consists of progressive downspacing of wells, aided by a regional understanding of pressure gradients and fracture and stress orientations.

Extensive seismic experimentation has been performed over the Rulison "tight-gas" Field in west-central Colorado, USA, as part of the multi-year Reservoir Characterization Project. Over the past five years, three separate seismic surveys have been performed over this field, using 9-component seismic technology. This combined application of time lapse and multi-component seismic techniques has provided unique insights into fault and fracture orientations and reservoir pressure changes resulting from gas production. An additional seismic technique, passive microseismic monitoring, is supplying an additional reservoir perspective, confirming hydraulic fracture orientation estimates and quantifying the effectiveness of well stimulation efforts. In combination, the integrated application of multi-scale seismic, spanning time-lapse, multicomponent and passive measurements, is leading to better understanding of key properties determining well production in a typical tight-gas reservoir.

Reservoir Details

Fluvial sands of the Lower Cretaceous Williams Fork Formation, and their regional US Rocky Mountain equivalent, contain extraordinary gas reserves. In the Piceance Basin of west-central Colorado, low matrix permeabilities in the range of .1 to 2 microdarcies and porosities of 6 to 14% make economic gas production a challenge (Davis 2006). In the southern part of the basin, the Rulison Field produces gas from a 700-foot column of 20 to 30 stacked channels (Figure 1). With proper alignment with natural fractures, complemented with typically 4 or 5 hydraulic fracture treatments, effective permeabilities can be enhanced to between 10 and 50 microdarcies and individual wells can produce over 1.5 BCF.

Traditional development strategies in tight-gas reservoirs consists of methodically placing vertical well paths at increasingly denser spacing intervals. Current well spacing in the Rulision Field ranges between approximately 10 and 20 acres. Similar tight-gas fields in adjacent basins have well spacings as dense as 5 acres and often share common surface pads for reduced environmental impact. Optimization of well placement and completions requires reliable estimates of pressure and both fracture orientation and density.

Challenges for "Traditional" Seismic Data

The thin and complex nature of sand channels in typical tight-gas reservoirs presents considerable challenges to "traditional" seismic data. Interpretation of single P-wave surface seismic surveys can generally identify major interfaces like regional coals or unconformities, which may represent containing boundaries of reservoir zones (Figure 2). Similarity and seismic attributes can be instrumental in identify major fault zones, which may also represent limits of optimal production. With sand thicknesses in the range of 10 to 20 feet, traditional seismic data rarely has the resolution to aid in the identification of individual channel features. Horizon and fault interpretation, using seismic and similarity attributes, defines the major reservoir boundaries in the Rulison Field. In tight-gas reservoirs, however, key properties to understand are pressure and fracture orientation and density. While the curvature "family" of attributes can provide some insight into fracture character, single seismic volumes generally provide limited value in tight-gas reservoirs. A trio of emerging seismic technologies: time-lapse, multicomponent, and microseismic may offer new options for better understanding tight-gas reservoirs.

Time Lapse Seismic

Time lapse seismic techniques are typically applied to thick, high-porosity sand reservoirs to monitor large fluid movements. Due to the low permeability of tight-gas reservoirs, fluid flow is likely not measurable in seismic data. However, pressure changes within or below the reservoir zone may sufficiently modify acoustic properties to be measured by time-lapse differences in travel times and/or amplitude.

Comparison of P-wave seismic data acquired in 2006 and 2004 to a baseline 2003 survey produces similar time difference volumes with values ranging from a fraction of a millisecond in the south to 5 milliseconds towards the north, within the main producing zone. (Figure 3). Time-lapse amplitude differences exhibit considerable spatial variability, and may be related to localized pressure changes from well production. Previous studies have found the largest time-lapse effects in the underlying coals, possibly related to pressure changes related to gas migration into the shallower fluvial sands (Keighley 2006).

Multi-Component Seismic

By measuring the same rock and fluid matrix with primary and shear waves, multi-component seismic can provide tremendous insight into reservoir properties. The "registration" of modeconverted (primary-to-shear) or pure shear-wave data to match P-wave data creates a vertically and spatially varying measure of primary and shear velocity ratios. Comparison of “fast” versus “slow” mode-converted and shear-wave volumes may provide additional insight into azimuthal anisotropy, possibly related to fracture orientation and density.

Time differences of 50 ms and more in shear anisotropy measurements may indicate that significant fracture densities exist, approximately orthogonal to the “slow” propagation direction. (Figure 4) Previous work by LaBarre 2006 indicates that anisotropy aligns orthogonally with the major fracture orientation of approximately 110 degrees from north. Gamma values do not appear to align along any preferred direction and may be related to major channels features.

Microseismic

Passive monitoring of microseismic fracturing is commonly used to monitor the effectiveness of hydraulic well treatments. By “listening” in an adjacent well for “micro earthquakes”, generated by induced fracturing, much can be determined about the zone of effective reservoir contact. This information is invaluable for positioning future wells to align with natural fracture orientations as well as aiding in the optimization of treatment parameters such as pressure, proppant concentration, and hydraulic fluid volumes used (Figure 5).

For the Rulison project, microseismic measurements indicate alignment (largely east-south-east) with the major fracture orientation indicated from FMI logs (Higgins 2006). Previous microseismic interpretations indicate a fracture azimuth of 103 degrees from north and fracture lengths of about 400 feet. Some fracturing patterns are distinctly asymmetrical, which may indicate interaction with macro-faulting or other tectonic features (Riley 2006).

Summary

In a typically tight-gas reservoir, the value of traditional seismic data is for interpretation of reservoir-bounding horizons and faults. Time and amplitude differences in time-lapse seismic volumes may indicate local and regional reservoir pressure changes. Multi-component seismic measurements of shear anisotropy and gamma may highlight fracture orientation and density, and major channel features. Microseismic data indicates that the major fracture orientation is approximately 100 degrees, agreeing with previous measurements and other sources of fracture information. New seismic technologies provide valuable insight into key tight-gas reservoir properties that are essential for optimizing well placement and production.

Acknowledgments

Huge thanks to Williams and the Reservoir Characterization Project for data access.

Selected References

Cumella, S., and D.B. Ostby, 2003, Geology of the basin-centered gas accumulation: Rocky Mountain Association of Geologists Piceance Basin Guidebook, p. 171-193.

Davis, T., 2006, Reservoir Characterization Project Semi-Annual Report, Colorado School of Mines, Golden, Colorado.

Higgins, S., 2006, Reservoir Characterization Project Semi-Annual Report, Colorado School of Mines, Golden, Colorado.

LaBarre, L., 2006, Reservoir Characterization Project Semi-Annual Report, Colorado School of Mines, Golden, Colorado.

Keighley, D., 2006, Reservoir Characterization Project Semi-Annual Report, Colorado School of Mines, Golden, Colorado.

Riley, B., 2006, Reservoir Characterization Project Semi-Annual Report, Colorado School of Mines, Golden, Colorado.

Wolhart, S.L., C.E. Odegard, N.R. Warpinski, C.K. Waltman, and S.R. Machovoe, 2005, Microseismic fracture mapping optimizes development of low-permeability sands of the Williams Fork Formation in the Piceance Basin: Society of Petroleum Engineers, SPE 95637.

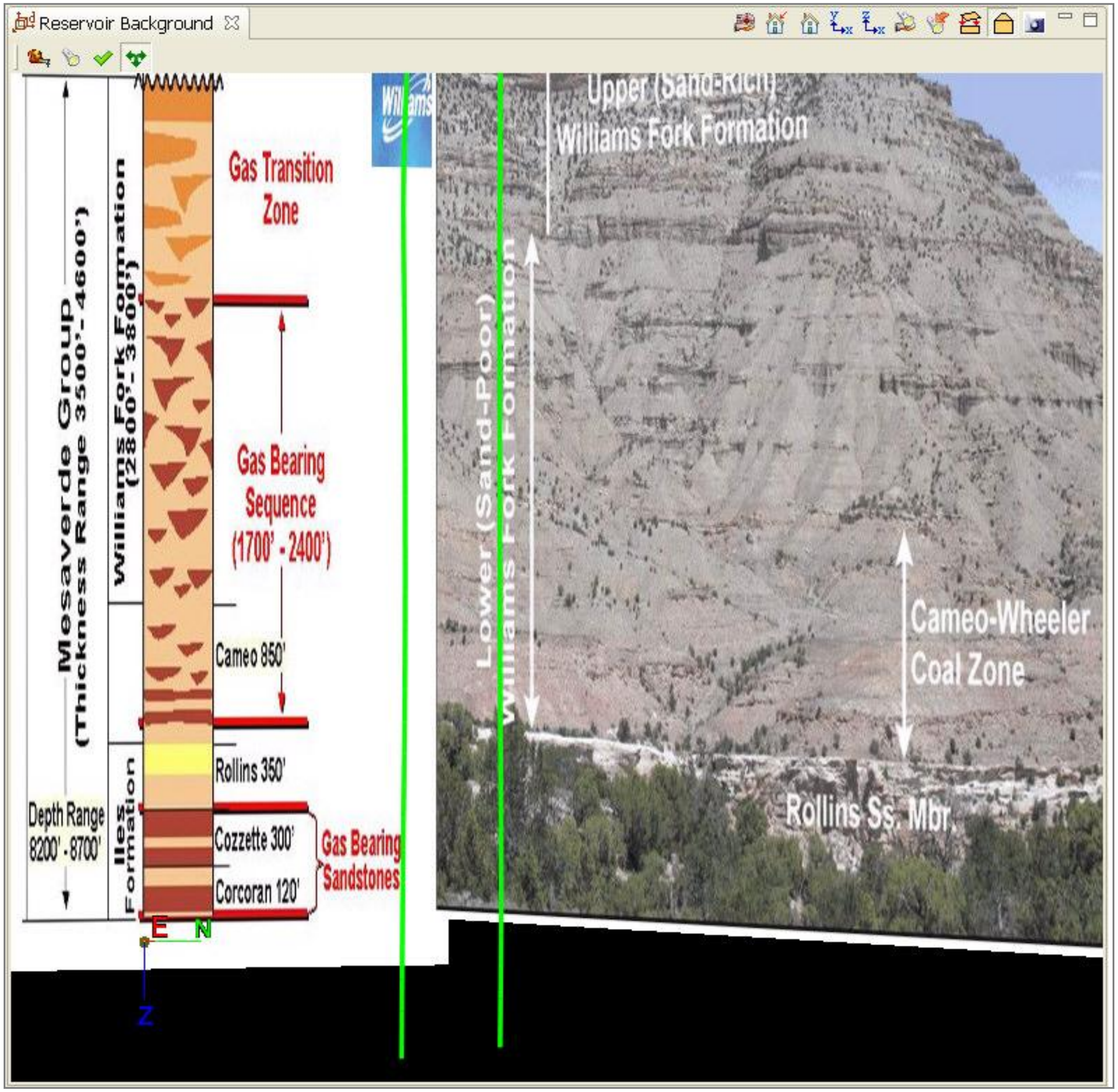

Figure 1. Outcrop showing stacked fluvial sands of the Mesaverde group which provide 700+ feet of gas-bearing reservoir in the Rulison Field of west-central Colorado.

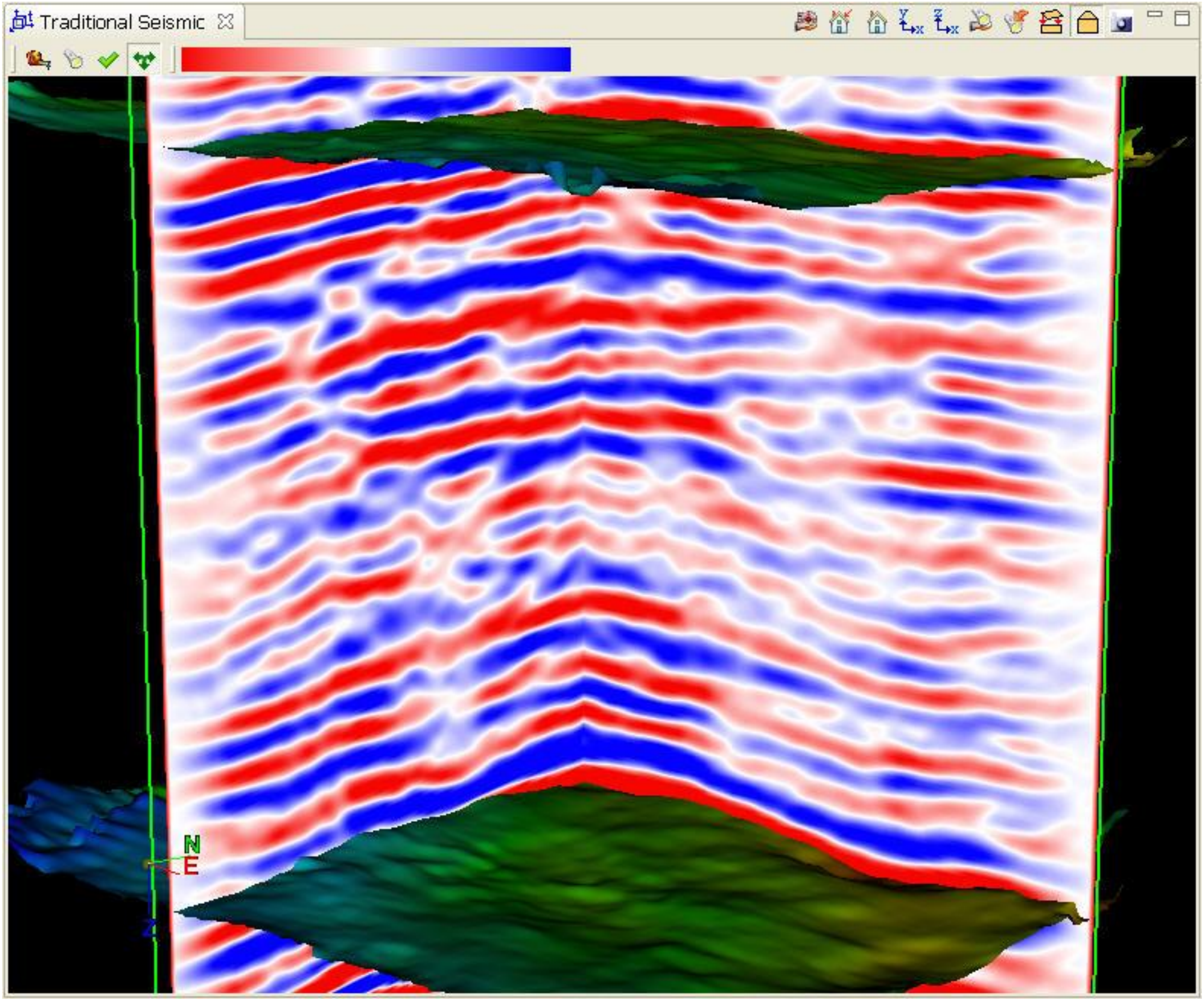

Figure 2. Traditional seismic data is useful for determining major reservoir interfaces but is generally not able to resolve fluvial channel features in the Mesaverde group.

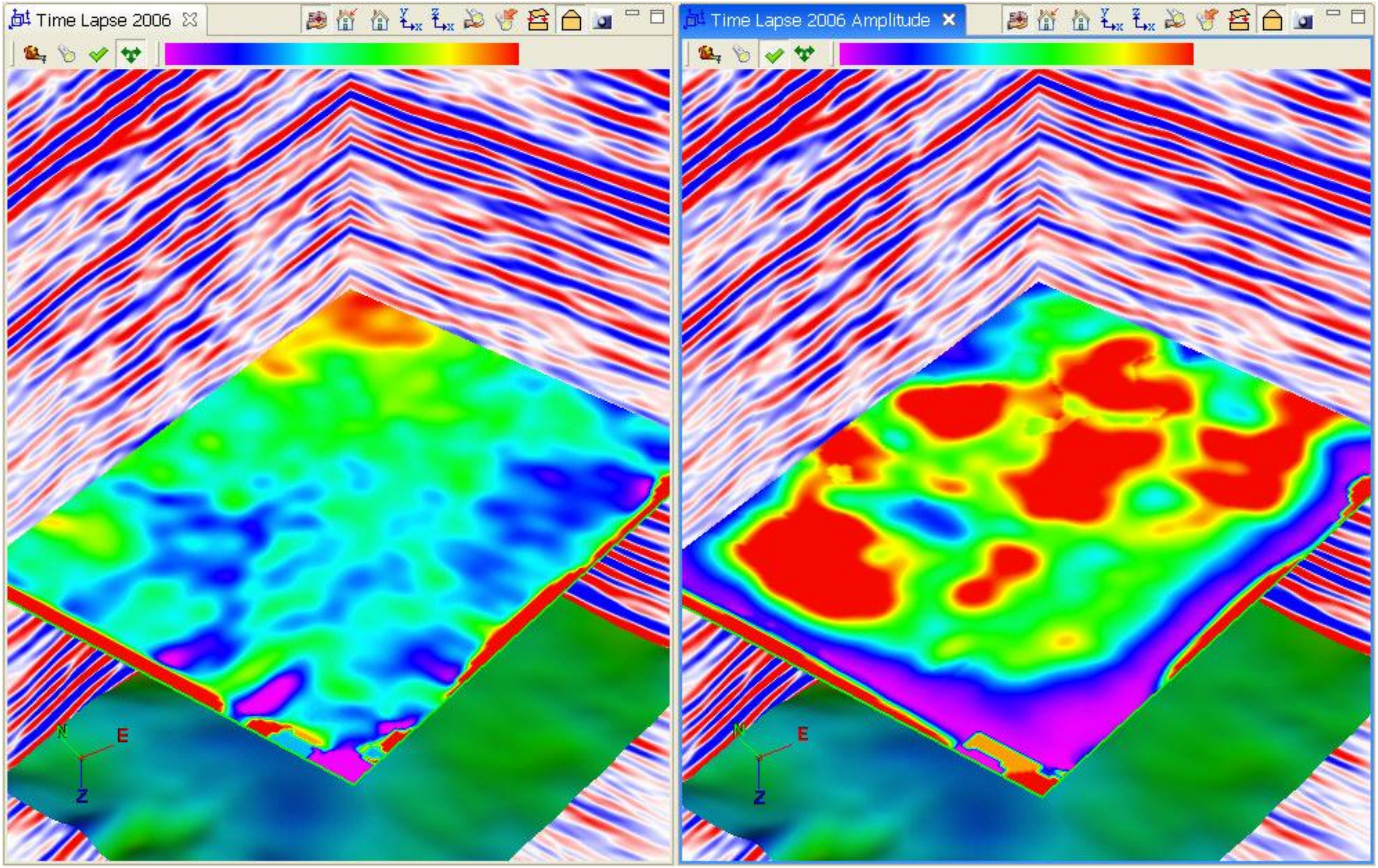

Figure 3. Time lapse travel time differences (left) and amplitude differences (right) may be indicative of pressure changes in the reservoir

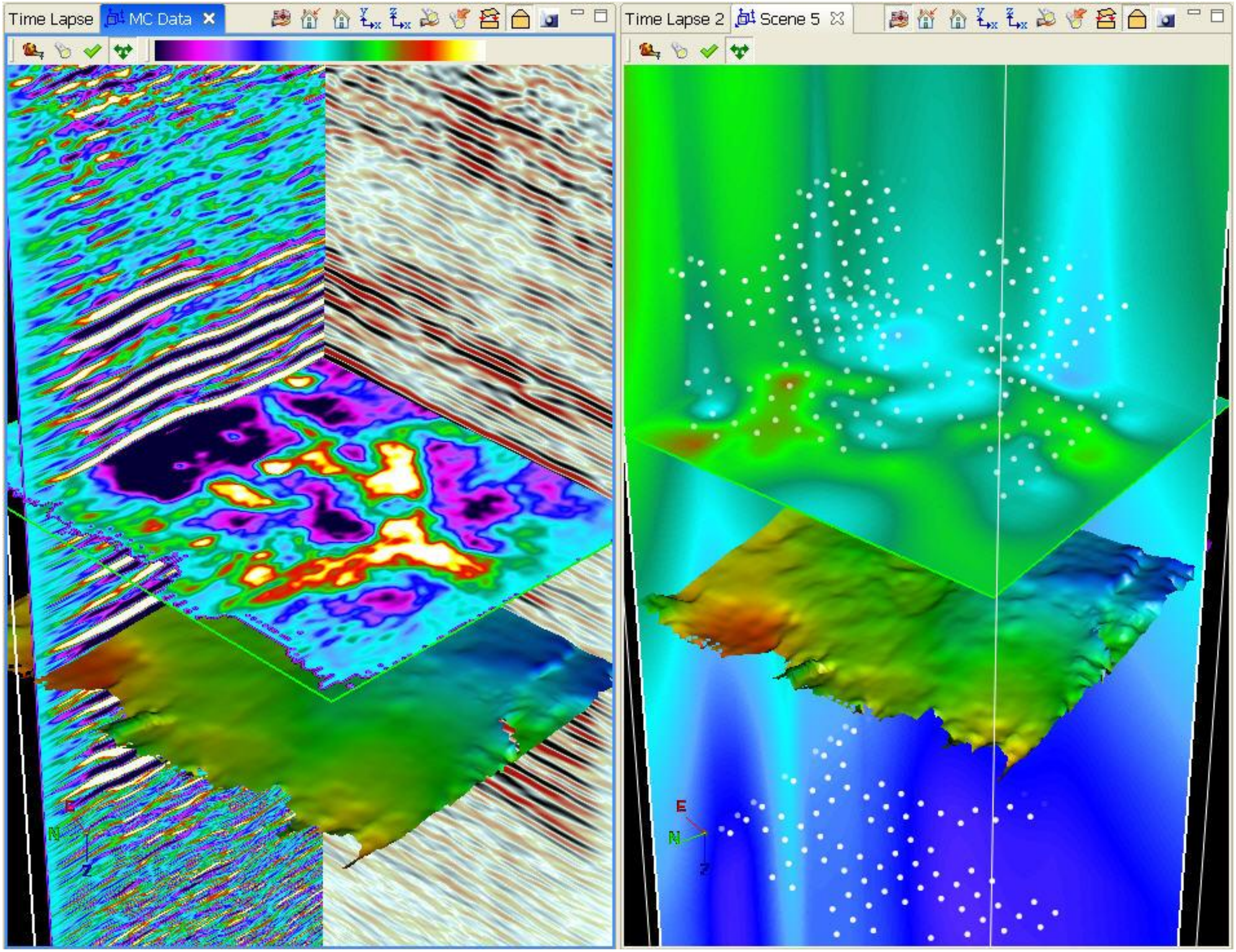

Figure 4. Anisotropy time differences (left) and estimates of gamma (right) provide insight to fracture orientation and density in the Rulison Field.

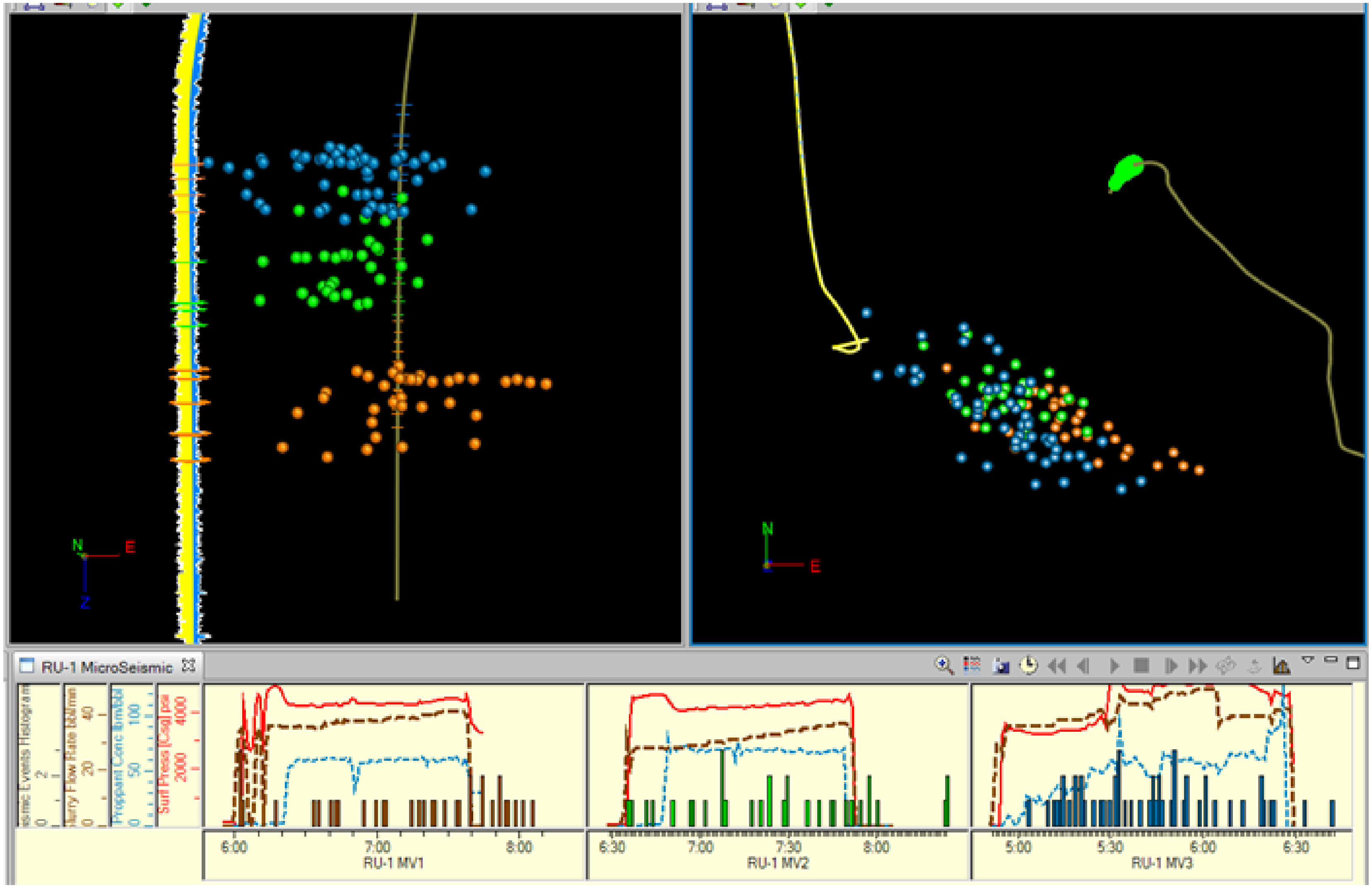

Figure 5. Map and cross section views of microseismic monitoring locations (top) and well treatment data like pressure, proppant concentration, and flow rate (bottom).