North American Shale Gas Reservoirs - Similar, yet so Different..*

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Abstract

Recent estimates of recoverable gas from unconventional shale reservoirs in the US exceed .5 qcf (quadrillion cubic feet) (USGS 2009) with potential for another .1 qcf in Canada (NEB). While broadly distributed, North American shale gas basins generally follow a trend of thrust belts and a Mississippian/Devonian shale fairway from Western Canada and into the Western, Southern, and Eastern United States.

North American shale gas reservoirs currently rank as 6 of the largest 22 global gas fields, based upon estimated recoverable reserves, with average recovery factors of about 20%. Innovations in horizontal well drilling and completions, supported by 3-D seismic, microseismic, FMI/FMS, and other measurements, are unlocking North American gas supplies for the decades ahead. Large well production variability, even within the same field, challenges our intuition about the simple, consistent nature of shale formations, and the gas within.

With a motivation to understand why "all gas shales are not created equal" - this study integrates published data, type logs, accessible seismic, and microseismic data along with 5 years of experience across most significant North American shale gas basins. Our tabulation of shale gas reservoir characteristics and well log analysis highlights key production differentiators including depth, thickness, porosity, pressure, and TOC. While basins and reservoir characteristics clearly vary - this does not explain significant well-to-well gas production variations. Part of this variability in production performance is related to evolutionary and company-to-company differences in fracturing "best practices".

It is our work with 3-D seismic and microseismic, however, that clearly supports the concept of shale gas "sweet-spot" fairways and converse "dead zones". Whether it is faulting in the Woodford, karst collapse chimneys in the Barnett, natural fracturing in the Marcellus, or clay/silica content in many plays - seismic and microseismic data provide valuable calibration and prediction tools for

mapping productive/non-productive fairways. Multiple data examples from key North American shale gas plays will be used to illustrate the unique characteristics of the most and least prolific gas producing regions

Overview

Recent estimates of recoverable gas from unconventional shale reservoirs in the US exceed .5 qcf (quadrillion cubic feet) (USGS 2009) with potential for another .1 qcf in Canada (NEB). While broadly distributed, North American shale gas basins generally follow a trend of thrust belts and a Mississippian/Devonian shale fairway from Western Canada and into the Western, Southern and Eastern United States (Figure 1).

North American shale gas reservoirs currently rank as 6 of the largest 22 global gas fields, based upon estimated recoverable reserves, with average recovery factors of about 20%. Over 60 potential shale plays have been identified in Canada and the US, with many more in Europe, China, Russia, and beyond. Innovations in horizontal well drilling and completions, supported by integration of 3-D seismic, microseismic, FMI/FMS, and other measurements, have been key to the pioneering shale work in North America.

Horizontal drilling and completions were also instrumental in unlocking the oil potential of the Bakken, and adjacent formations, in the Williston Basin, over the past decade. Recently, pricing disparities between equivalent energy volumes of oil and natural gas are driving application of unconventional techniques to oil, condensate, and natural gas liquids, in plays like the Eagle Ford, Barnett, and Marcellus.

Motivation

With an objective to understand why "all shale plays are not created equal" - this study integrates published data, type logs, accessible seismic and microseismic data along with 5 years of experience across most significant North American shale basins. Our tabulation of shale gas reservoir characteristics and well log analysis highlights key production differentiators including depth, thickness, porosity, pressure, and total organic carbon (TOC). While these basins and reservoir characteristics clearly vary - this does not explain significant well-to-well production variations.

Observations

Our "unconventional interpretation" work with 3-D seismic and microseismic, petrophysical, geochemical, and various engineering data clearly supports the concept of shale oil and gas "sweet-spot" fairways and converse "dead zones". Whether it is faulting in the

Woodford, collapse chimneys in the Barnett, natural fracturing in the Marcellus, or clay/silica content in many plays - data integration is essential for mapping productive/non-productive fairways.

In our work, four "families" of maps have proven useful for predicting how shale reservoir rocks will fracture and what "prizes", in the form of producible hydrocarbons, are accessible. In simple terms, these maps aspire to highlight: 1) hydrocarbon potential (Figure 2), 2) rock "crackability", 3) existing fractures, and 4) induced fractures.

Hydrocarbon Potential Maps

Unconventional shale reservoirs often act as source rocks for shallower clastic and carbonate reservoirs. As such, the same geochemical techniques used to understand the quality of these sources rocks are applicable for understanding the hydrocarbon potential of these source/reservoir/trap resources. Estimates of TOC, hydrogen and oxygen index, and thermal maturity are important for estimating the amounts and type of hydrocarbons in place. Rock matrix porosity is linked with organic porosity in kerogen to dictate how much free and adsorbed gas or liquids are accessible. Finally, reservoir zone thickness factors in to determine total amount of hydrocarbons in place per section. Figure 2 illustrates two components, TOC and shale zone thickness, for estimating hydrocarbon amounts in the Montney shale of northern Alberta and British Columbia.

Rock Crackability Maps

The economics of shale plays is contingent upon the ability to create permeability with hydraulic fracturing - which is dependent upon the brittle/ductile characteristics of the reservoir rocks. Ironically, "shales" are the last rocks operators hope to find - due to the high ductile nature of clays. Understanding and mapping mineralogy - specifically clay content relative to brittle components like silica, calcite and carbonate - is important for predicting "crackability" (Figure 3). Multi-variate statistical integration is essential to bridge across measurements of: seismic (e.g. mu-rho, lambda-rho), lithology, facies, rock mechanics, and mineralogy - to predict crackability with metrics such as breakdown pressure - the stress required to initiate hydraulic fracturing.

Existing Fracture Map

Existing faults and fractures can prove to be a help or hindrance to unconventional well production. Seismic attributes, including incoherence and curvature, are often useful indicators of fault and fracture trends. Correlation with well-based dip meter and FMI/FMS logs or regional magnetic field measurements are examples of techniques for calibrating structural seismic attributes (Figure 4). Other seismic attributes, such as multi-azimuth velocity anisotropy, are often useful for estimating relative fracture densities within shale reservoirs. Fracture chimneys in the Barnett play and faulting in the Marcellus, Woodford, and Eagle Ford shales are prime examples of geohazards to avoid with well path planning. Conversely, existing natural fractures can be key to creating a complex induced fracture pattern with large stimulated reservoir volumes.

Induced Fracture Map

Rock character and existing fractures can be important influencers of hydraulic fracture effectiveness - but it is the dynamic stress field that drives the actual induced fracture pattern. Tectonic forces play a major role in defining maximum horizontal stress in North American shale plays tracking along the Rocky Mountains (Laramide), Ouachita, and Appalachian thrust belts. This dominate horizontal stress often trends along a southwest/northeast orientation - which generally drives horizontal well trajectories along a perpendicular path.
Microseismic monitoring from downhole and/or surface sensor arrays has emerged as the preferred in situ technique for induced fracture mapping. Continuous improvements in measuring, detecting and accurately locating microseismic events is providing the means for mapping fracture network patterns and estimating the total amount of stimulated reservoir volume. Correlating microseismic data with stress estimates and lineament maps (Figure 5), obtained from core and seismic anisotropy measurements, can be instructive for understanding fracturing complexity.

Interestingly, dominate maximum horizontal stress (i.e. high stress anisotropy) can actually be detrimental - producing a simple and ineffective "bi-wing" fracture pattern. In less anisotropic scenarios, where maximum and minimum horizontal stress are more comparable, a more complex fracture pattern may develop, as fracturing can more easily proceed along multiple azimuths.

While perhaps the most powerful "sweetspot map", the prediction of induced fractures is challenging due to the dynamic nature of the reservoir stress field. Each stage of a horizontal well hydraulic fracture not only affects stresses for subsequent, adjacent stages, but also adjacent wells. A "zipper" type of well-to-well interaction is often desired and planned - and we have found that a methodical interpretation of stage, well, and pad stimulated reservoir volumes is the best way to model fracture behavior.

Application

When confronted with the challenges of shale reservoirs, there is a temptation for operators to either simplify operations to an engineering-led, "gas factory" approach or to forgo "traditional thinking" to develop novel, complex approaches - for competitive advantage. While these approaches may work in certain scenarios, we have found that a balanced, unconventional interpretation workflow is most appropriate. Comparison across major North American shale plays reveals that much of what we have learned in traditional plays is applicable (i.e. thickness, porosity, permeability do matter) but our experiences with traditional reservoirs need to be tempered with unconventional reservoir factors that may be more important to well performance (i.e. TOC, thermal maturity, rock crackability, natural fracturing, and stresses).

Depths, geologic ages, and structural complexity vary considerably across the oil and gas shale plays that we have studied. On the other hand, low clay content, moderate-to-high TOC, higher thermal maturity, higher pressure gradients, and higher temperatures are similar characteristics we see for better gas-in-place shale reservoirs. The unconventional interpretation workflows that we find most appropriate produce a combination of maps (or 3-D geologic models) that highlight: 1) hydrocarbon potential, 2) rock "crackability", 3) existing fractures, and 4) induced fractures.

1) Hydrocarbon potential maps rely heavily upon geochemical modeling of TOC and thermal maturity, coupled with regional and local reservoir thickness mapping.

2) Rock crackability maps are very powerful predictors of rock behavior that we find require a multi-variate non-linear or neural network approach to blend together seismic, well log, petrophysical, rock mechanical, and engineering data.

3) Existing fracture maps can be created using cluster analysis or integrated visualization and interactive crossplotting of incoherence and curvature seismic attributes.

4) Induced fracture maps are the most challenging to produce, due to the dependence upon the rock crackability and existing fracture maps - and the difficultly of measuring dynamic in situ stresses. Multi-azimuth seismic for velocity anisotropy estimation has shown some promise, along with seismic curvature, for modeling stress anisotropy effects. We have found that improved microseismic data is creating opportunities to map fracture pattern complexity and thereby infer maximum stress orientation and relative amount of stress anisotropy.

Shale oil and gas plays are rarely homogenous or isotropic in their characteristics. Optimized development of these resources requires a step-change in workflow sophistication to extend beyond traditional understanding of thickness, porosity, permeability, etc. We believe the solution lies with an unconventional interpretation approach that completely integrates the skills, data, and workflows across the asset team to include: geophysics, geology, petrophysics, geochemistry, rock mechanics, and the combined contributions of drilling, completions, reservoir, and production engineers.

Figure 1. Sweetspot fairway of North American shale plays - with total estimated (red) and producible (white) hydrocarbons in place.

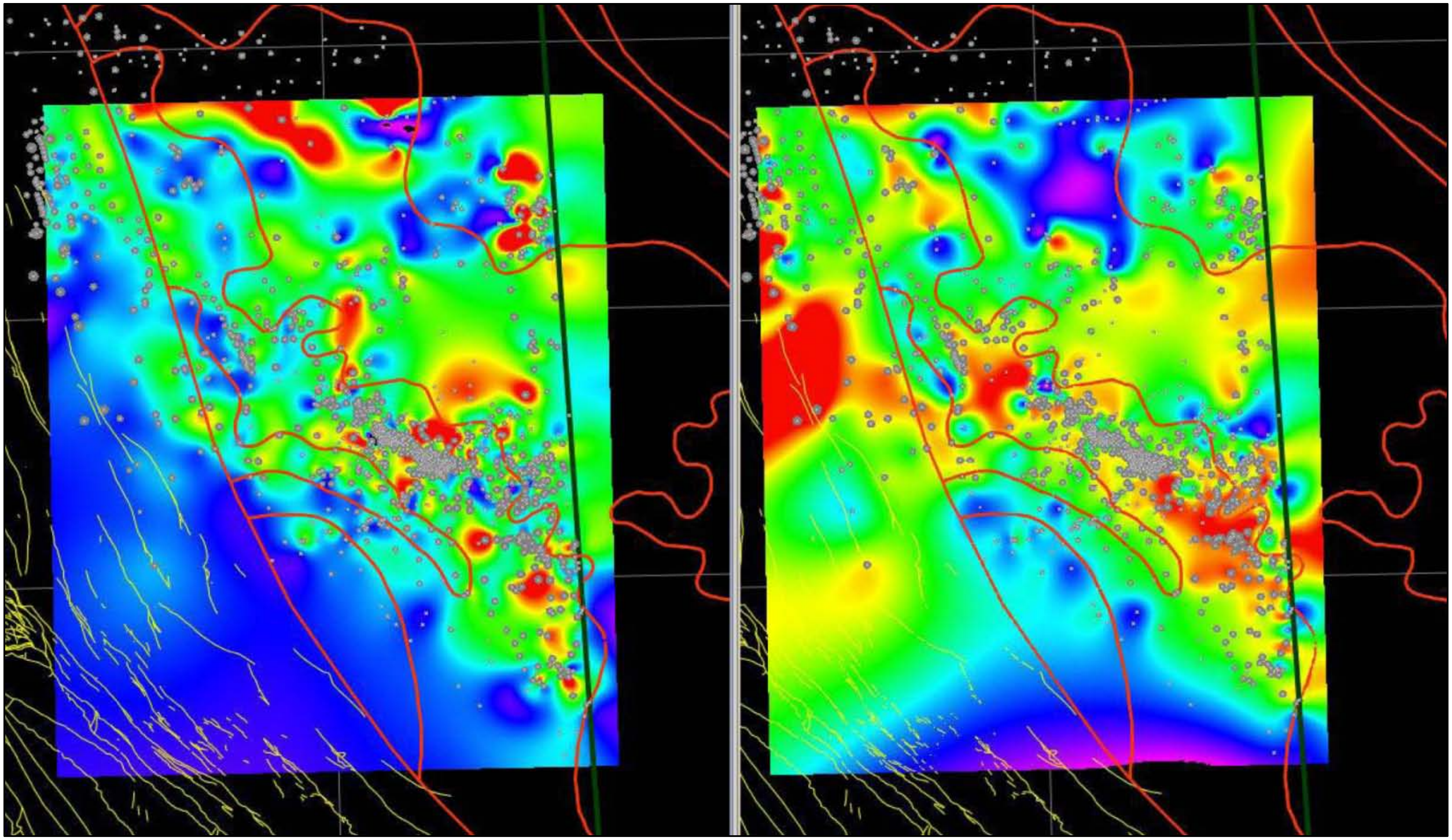

Figure 2. Total organic carbon (left) and shale thickness (right) maps are useful for mapping hydrocarbon potential (BC EMPR)

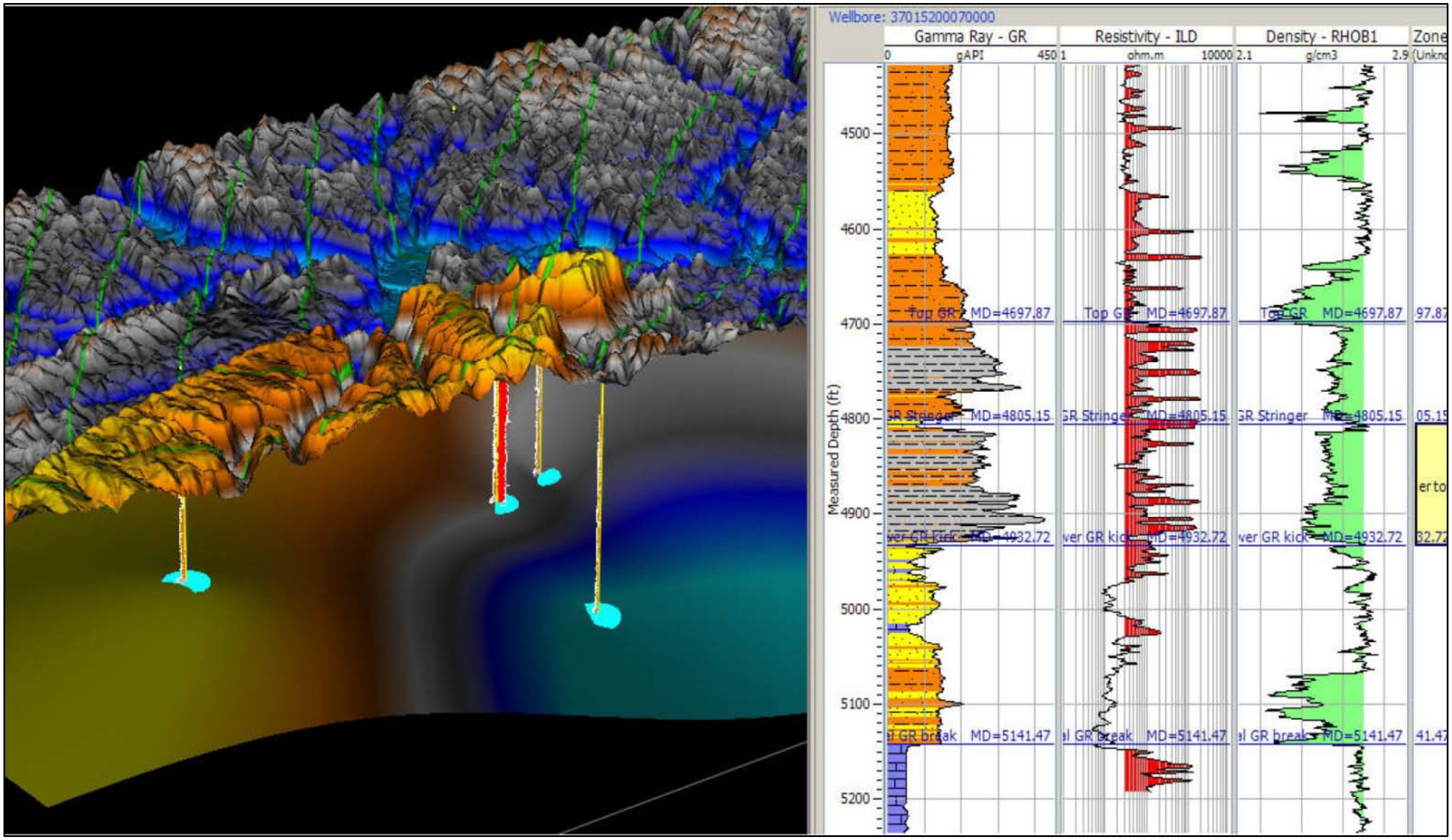

Figure 3. Raw well data (right) can be combined mathematically or statistically to create spatial estimates of extractable properties like lithology or clay content (left) in this example from the Marcellus shale play. Data from USGS and WVGS.

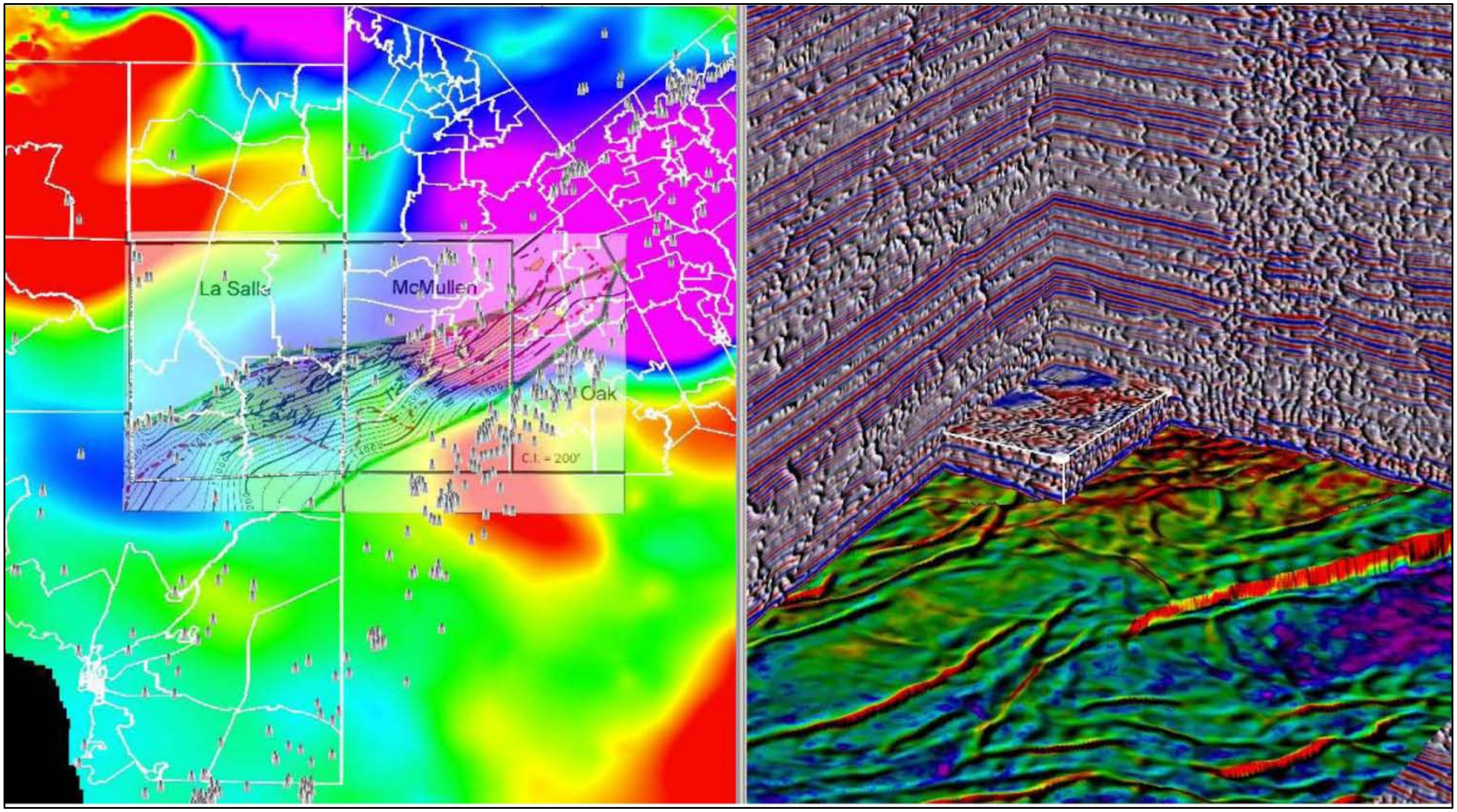

Figure 4. Visualization of seismic incoherence and curvature attributes (right) illustrates major faulting and minor fracturing in the Eagle Ford shale. Magnetic anomaly data can be correlated with regional fault interpretations (left). Seismic data courtesy of Global Geophysical. Other data from USGS, Texas RRC PetroHawk corporate presentation.

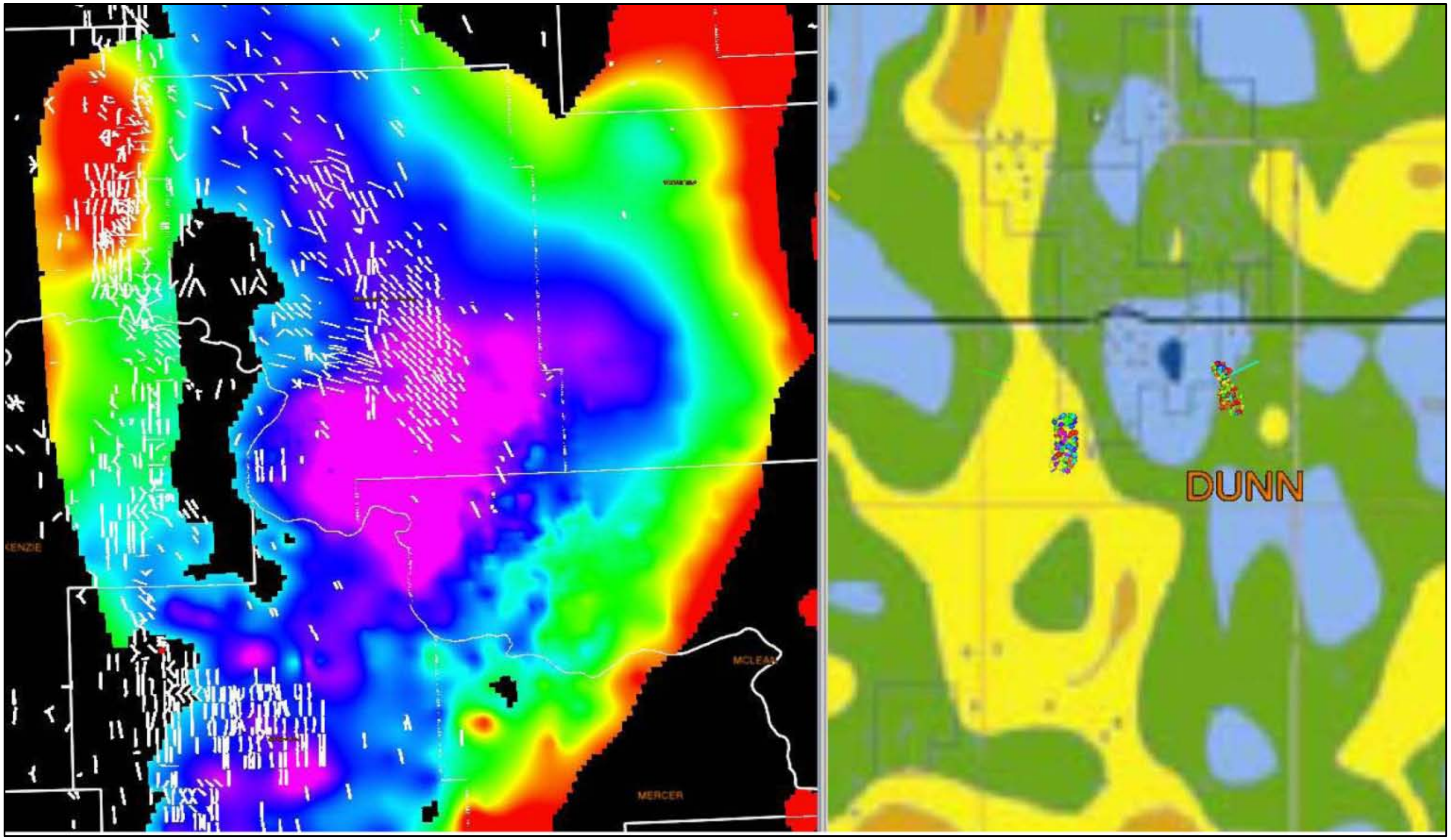

Figure 5. Stress and lineament density maps can be correlated with microseismic data (right) to predict complexity and effectiveness of hydraulic fracturing. Horizontal well orientations in the Bakken shale are aligned with the Nesson anticline and other features, highlighted with gravity and magnetic anomaly data (left). Data from North Dakota Geologic Survey and USGS.