10.1071/PVv2011n155p28

Eagle Ford Shale exploration: integrated regional geology, seismic and microseismic analysis

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Introduction

The Eagle Ford Shale in South Texas (Figure 1) is one of the more exciting shale plays in the United States at the current time. Recently published reports of well tests describe initial gas well rates exceeding 17 mmcf/d and initial oil well rates in excess of 2500 bopd. Acreage lease rates continue to climb as additional positive results come from drilling within the trend. A key issue for the exploration companies is finding where to focus acreage acquisition and optimise drilling plans for optimal gas and oil recovery. This paper first considers the geologic context of the Eagle Ford and then examines the geologic drivers for locating economic producing wells. With improved understanding of local rock properties, focus shifts to geophysical techniques, in particular, the use of 3D seismic data and microseismic data from frac monitoring to build an understanding of a successful unconventional play.

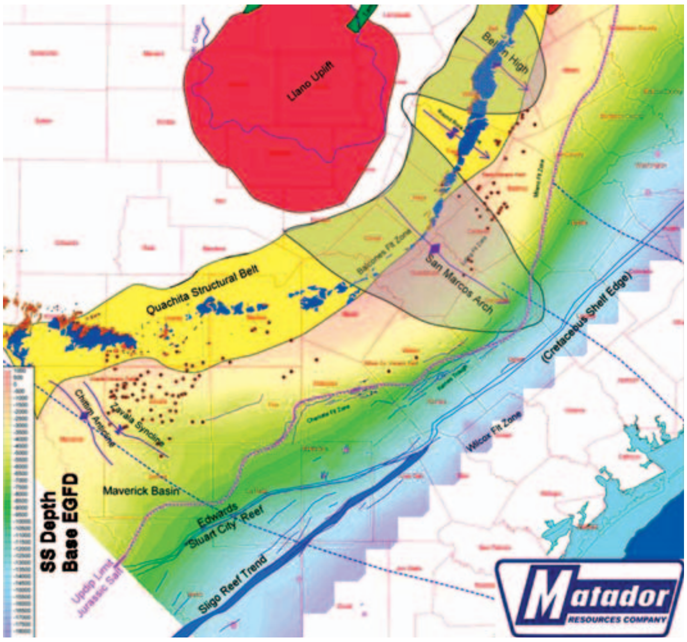

Fig. 1. *Tectonic setting of the Eagle Ford with post 2008 Eagle Ford activity.*

Since the first publicly reported, significant gas shale test by Petrohawk in the Dora Martin #1 on 16 October 2008 (9.7 mmcfg/d), the play has expanded to now cover ~11 000 square miles (~7 mmac). Over 1500 wells are believed to have either been drilled or permitted in the play. What has emerged is a well defined down dip gas play that transitions rapidly up dip into less well defined wet gas and oil fairways. While there are several large independents who have pioneered the play, the extent of the play area has provided ample opportunity for additional small companies to join the exploration effort. The resulting high level of activity has created a rapidly expanding need for viable tools to high-grade areas to reduce economic risk.

Geology

The Upper Cretaceous (Cenomanian to Turonian) age Eagle Ford Shale (Figure 2) was deposited during an extreme marine high-stand that saw marine incursion deep within the North American continent. The depositional framework in the south Texas area resulted in the accumulation of varying thicknesses of deep water, organic rich marine shales. The form of this marine environment was largely controlled by the interaction of basement zones of weakness, underlying carbonate paleogeography, salt tectonics, and eustatic sea level. Deeper stratigraphic successions impacting the paleogeography are the Louann salt, and the paleo reef margin deposition of the Sligo and the Edwards (Stuart City) formations. Tectonically, the local area was relatively quiet with small, but significant gravitational sliding in a south-easterly direction towards what is now the modern Gulf of Mexico. A southern bounding low, the Bisbee–Chihuahua trough was rapidly deepening. Additionally, intrusive and extrusive volcanics occurred in the north and western parts of the basin.

Lowstands preceding and during deposition generated a regional flooring carbonate horizon (the Buda limestone) and an internal carbonate marker (the Kamp Ranch member) that divides the organically rich basal section (lower Eagle Ford or Britton/Pepper Shale) from the overlying leaner and more calcareous member (upper Eagle Ford or Acadia Park). The calcareous source section is down lapped unconformably by the overlying prograding Austin Chalk formation.

Rock property measurements: seismic and wireline

Rock properties of this succession are well suited for seismic analysis. The underlying Buda, a tight, massive limestone, is present regionally in most of the play area and ranges from 40 to 160 ft in thickness. As one would predict, seismic impedance

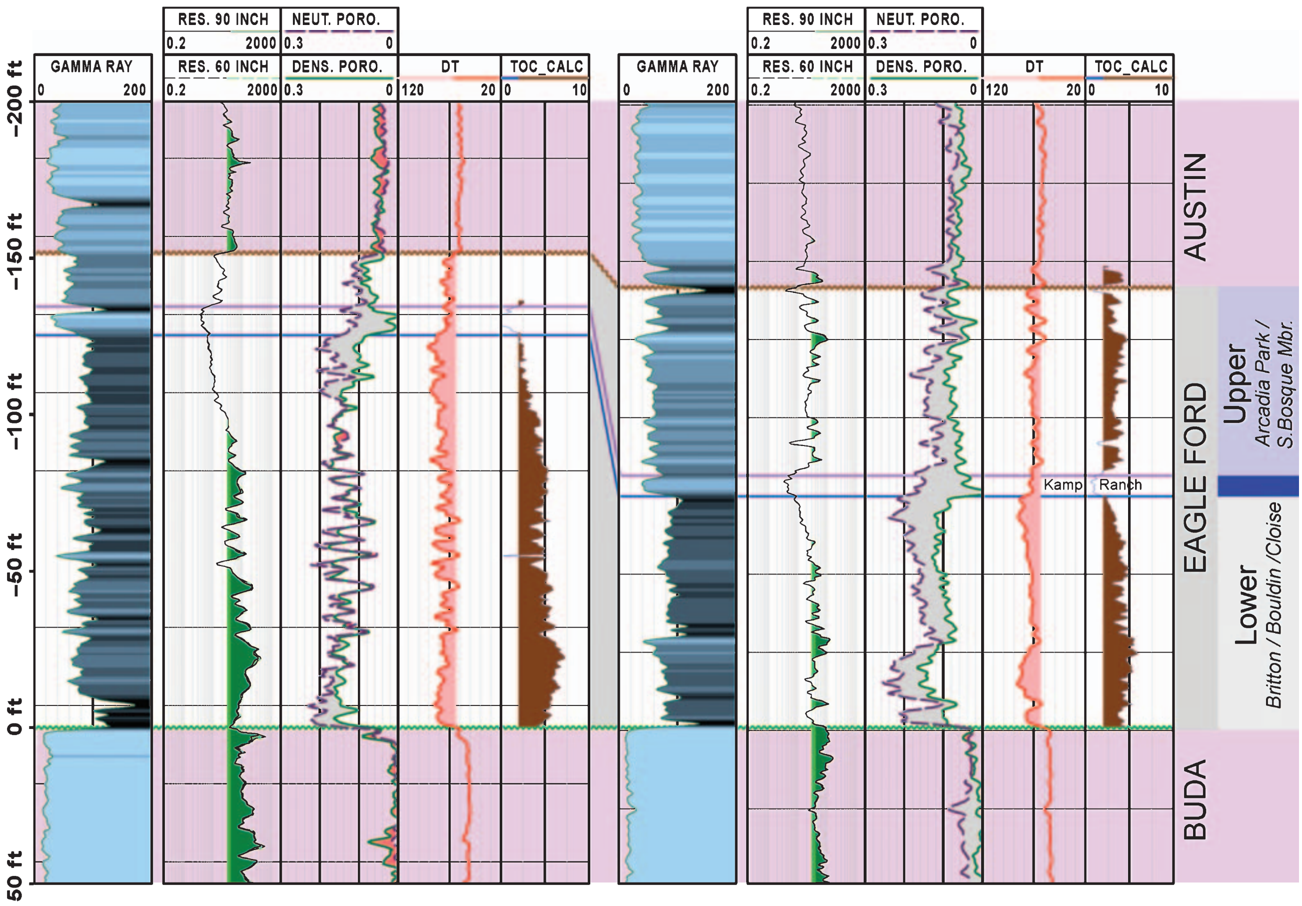

Fig. 2. *Stratigraphic variations within the Eagle Ford. Organics and the associated porosity generally increase toward the base of the section above a tight Buda limestone.*

values for this section are quite consistent and provide an excellent point of calibration for seismic inversion (converting the seismic wiggles into rock property predictions). Immediately above the Buda in the Eagle Ford the organic shales are often the richest (4–7% total organic carbon (TOC)) and most porous (7–15%) of the target interval. Impedance changes in the Eagle Ford commonly relate to changes in TOC and/or porosity. The top of the Eagle Ford is somewhat less well defined as the section grades into the Austin Chalk. The gradual decrease of porosity and organic content at this upper interface generally is not a clear reflection on the seismic data.

What makes the Eagle Ford play work is a thick Lower Eagle Ford interval with high TOC content possessing high porosity. Porosity is a combination of intercrystalline pores between loosely cemented microfossil debris and hydrocarbon expulsion pores positioned within the sourcing organic debris (kerogen). Additionally, evidence suggests that strained but not highly deformed settings enhance performance. Natural fractures of any size provide a larger permeability network.

Understanding the geomechanical properties of this sequence is extremely important in placing the horizontal bore hole within the section. The inter-relationship of the pore distribution, rock strength, and ensuing completion program impacts the ultimate recovery of the well. Advanced suites of wireline logs (Figure 3) designed to measure vertical and horizontal stress, brittleness, and existing fracture development are becoming the standards early on in any shale evaluation program. Data collected from directional sonic tools is key to extrapolating well results into the 3D seismic data.

Geophysical data and the Eagle Ford

Seismic data

Conventional subsurface data, such as wireline logs, cores and cuttings, are limited in availability to many companies currently exploring the play. Interpretation of these data is often ambiguous at best. As a result, thorough understanding of the regional aspects of the play remains elusive to many companies. Matador Resources believes that modern seismic data and interpretation techniques can add significantly to the database and greatly enhance regional understanding of the play. Newly acquired 3D datasets like the Reservoir Grade (RG) Patron Grande 3D from Global Geophysical Services provides a high-resolution characterization of the subsurface, which highlights drilling hazards (faults), and also offers the potential for identifying better reservoir quality intervals (higher TOC shale sections with greater porosity and fractures). Extracting rock properties from the seismic should be the goal of any processing and interpretation effort. Linking the results of well tests to the attributes derived from the seismic will provide operators with a far more reliable predictive capability in any shale play.

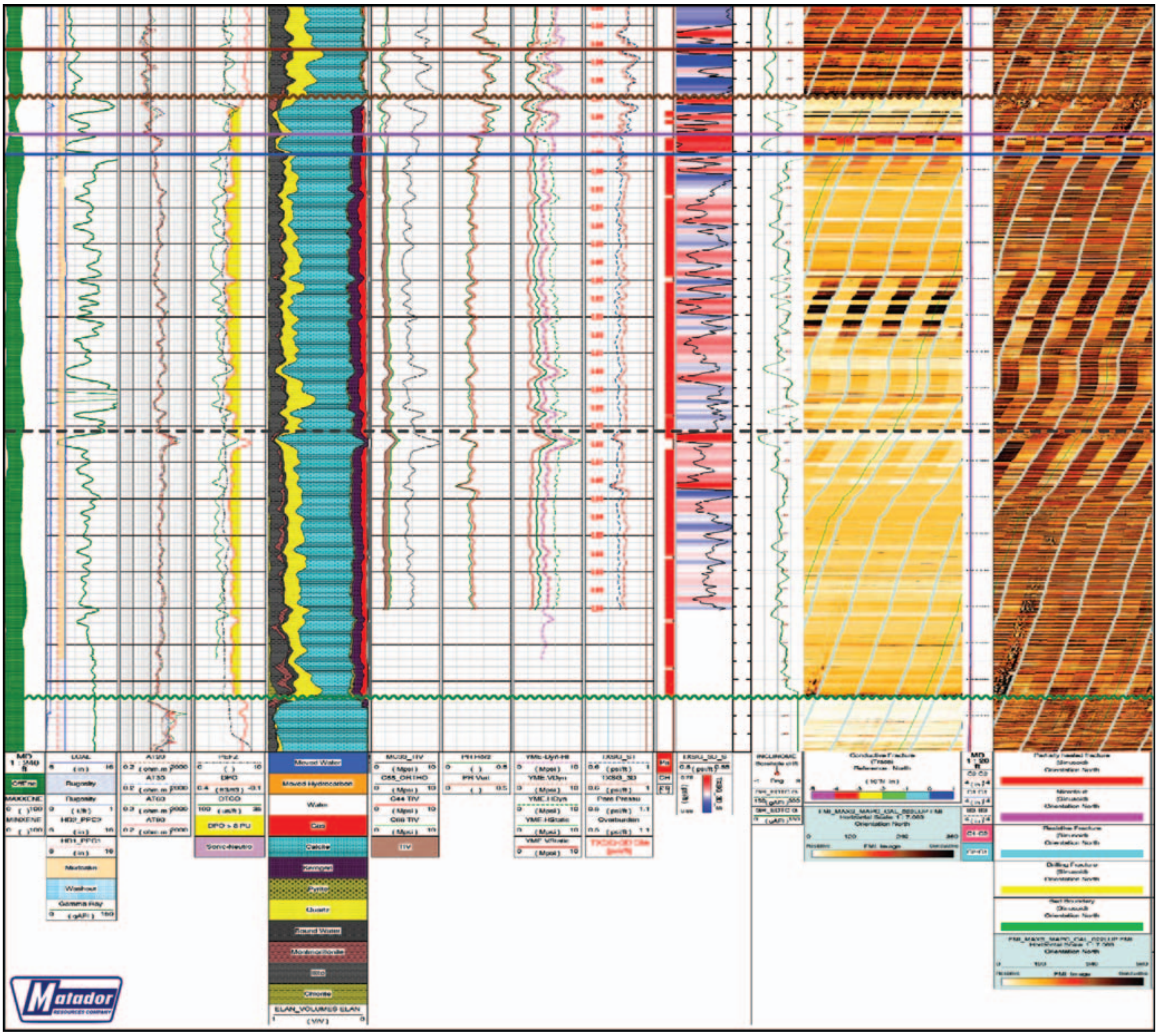

Fig. 3. *Direct rock state measurements (Dipole sonics and FMI) within the Eagle Ford are key to planning horizontal well positions and transferring the well data into a 3D space.*

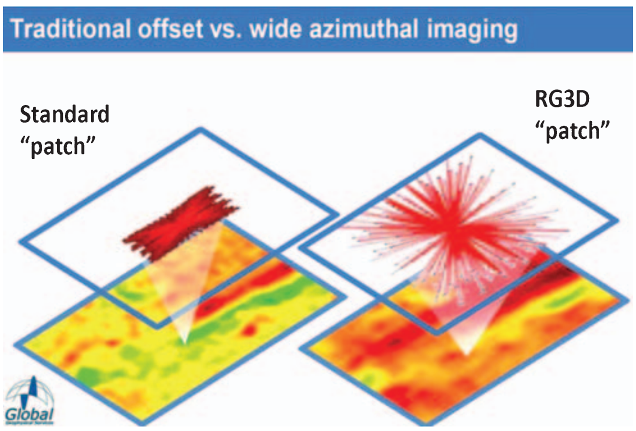

Fig. 4. *Standard versus RG3D (Reservoir Grade 3D) seismic acquisition layouts. The full azimuth, high channel count effort provides additional data for shale assessment.*

Seismic acquisition in the Eagle Ford and other shale plays has changed in the past few years to better accommodate some of the geomechanical goals of the field development (Figure 4). High channel count crews are providing full azimuth, long offset date volumes critical for better subsurface illumination, improved frequency content and improved rock property inversions. Traditional (channel limited, azimuth limited) seismic acquisition techniques under sample the subsurface limiting the use of the 3D dataset. Full azimuth shooting provides a dataset for seismic processing that can feed fracture prediction studies not possible in the older 3Ds.

Data processing

Full azimuth processing for fracture prediction from the seismic involves searching for velocity and amplitude differences in the Eagle Ford that change with azimuth. We expect open fractures and stress field variations to have a subtle impact on the seismic velocities and interface reflections which, with proper processing, can be extracted from the 3D data. Standard

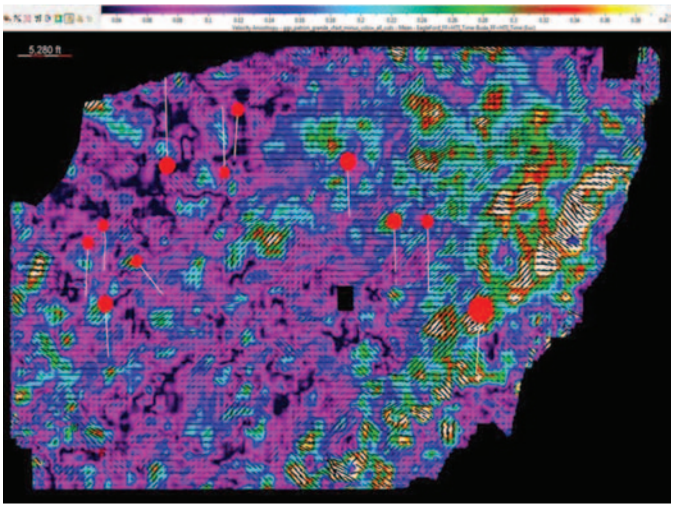

Fig. 5. *Map of azimuthal velocity variations within the Eagle Ford highlighting probable open fracture swarms or stress field variations. Color represents magnitude of azimuthal anisotropy (purple = low, white = high) and vector length and direction represent the orientation of the fast velocity within the Eagle Ford.*

processing assumes these changes aren't significant enough to hurt the final image so the effects are often ignored. Processing the data to highlight azimuthal variations is a relatively new technology in the industry but has shown promise in most US shale plays by highlighting potential open fractures or weak zones that impact fraccing. The most robust product from azimuthal processing is the orientation of the stress field – critical information for planning horizontal well placement.

The primary products of azimuthal processing are a pair of volumes describing areas where the velocity changes as a function of azimuth and a volume that describes the azimuth of the fast velocity. Faster velocity in one direction may indicate the direction of open fractures or the orientation of the local stress field. In the Eagle Ford section we see areas that show little change in velocity with azimuth (purple in Figure 5) and other areas that show strong changes (red-white in Figure 5). Open fractures can be both a positive and a negative factor in developing the resource depending on the response of the shale to hydraulic fracturing. Pre-drill prediction and mapping of potential fracture zones is an added benefit of a full azimuth acquisition and processing effort.

The other positive effect of addressing anisotropy in the processing (both azimuthal and layer anisotropy) is in improving the amplitude information in the far offsets. Elastic inversion involves the conversion of near and far offset seismic data into a prediction of attributes that can infer rock strength. Seismic processing that does not properly preserve far offset amplitudes will lead to less correct rock strength predictions from the elastic inversion. In areas where azimuthal and layer anisotropy are present, it's important to include anisotropy in the actual migration of the data. Unfortunately, the more standard approach in the industry is to correct for anisotropy post migration. Elastic inversion can provide density, Poisson's ratio and 'fracability' or rock strength prediction volumes to help identify sweet spots in the shale – only if the processing is done correctly. Predictions of ductile versus brittle rock behaviour (Figure 6) require careful processing and good calibration with well control to add value to the field development.

Interpretation

Once the processing is completed the seismic data can offer a number of tools for understanding the spatial distribution and quality of the Eagle Ford section. Mapping of the Austin Chalk and Buda horizons yields well constrained thickness maps central to the development of reliable gas or oil in place maps. Acoustic impedance inversion is the simplest and most robust first step in the pursuit of Eagle Ford rock properties. The inversion uses a 3D model, the seismic velocity field, and an estimation of the seismic wavelet to convert the seismic volume to an impedance volume. Rock property studies in the Eagle Ford indicate that impedance and porosity in the Eagle Ford are well correlated. Thus, inversion is an excellent tool for highlighting the best intervals in the shale (based on our current limited well control). Volume and surface attributes help highlight lineaments that may be associated with open fractures or zones of weakness. Figure 7 shows seismic amplitude in gray-scale highlighting small throw faulting at the base of Eagle Ford. These faults have throws of 20–300 ft and will greatly impact the portion of the Eagle Ford drilled in a 4500 foot lateral. Curvature and coherence help highlight more subtle

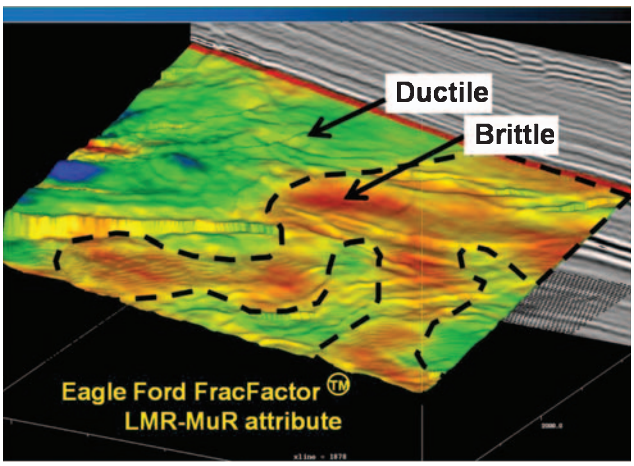

Fig. 6. *Map of the Eagle Ford from an elastic inversion and cross-plot analysis designed to highlight brittle versus ductile rock behaviour.*

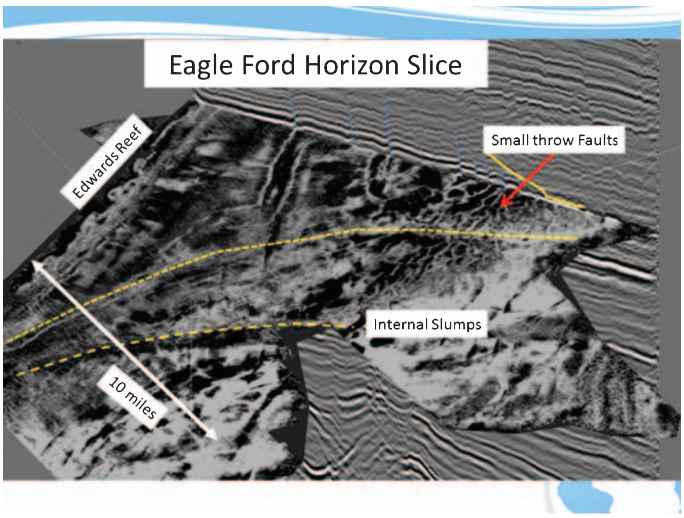

Fig. 7. *Faults and slumps apparent in Global Geophysical's Patron Grande Eagle Ford dataset. The faults impact well placement and frac designs.*

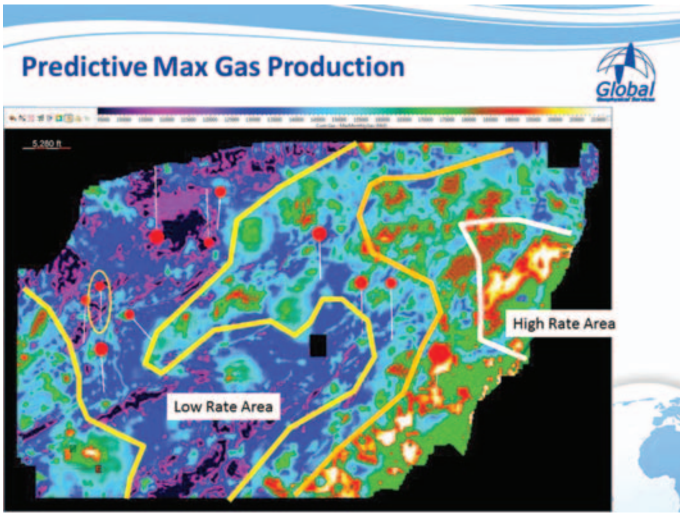

Fig. 8. *Map results from the multivariate statistical analysis predicting areas of higher production potential within the Eagle Ford.*

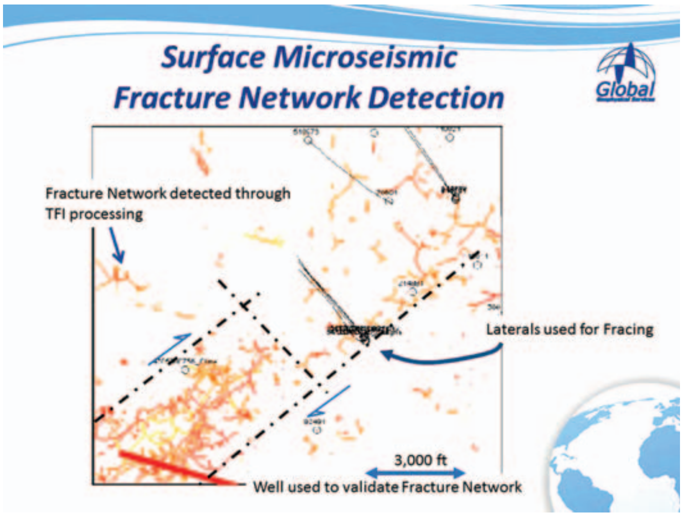

Fig. 9. *Microseismic monitoring can help highlight fracture networks for better well planning.*

lineaments that may be related to open or closed fracture systems.

With the completion of the processing and inversion it is time to attempt a link between the well results and the seismic. Multivariate statistical analysis allows us to compare attributes from the seismic to production and ultimately work towards a predictive model for mapping production potential. The work flow involves analyzing seismic and engineering attributes for potential performance indicators. From this work we select attributes that show a positive correlation to performance without showing high correlation to each other. Combining the attributes through a non linear regression allows for the creation of a predictive map for locating areas of better production potential (Figure 8).

With fracture predictions from the seismic processing, rock strength predictions from elastic inversion, and lineament analysis from surface attributes there is still a sizeable gap between what we infer from the seismic and what we know from the well data and regional geology. Frac monitoring to detect and map the microseismic events created by hydraulic fraccing is one way to help link the seismic predictions to the geomechanical properties and eventually to the reservoir performance. Receivers at the surface, in a buried array or downhole in a nearby well listen during the fraccing process to detect where the rock has been broken. Figure 9 shows a fracture network highlighted in a surface microseismic experiment in a non Eagle Ford reservoir. Integration of the frac monitoring with the seismic rock property predictions offers the best chance of high grading the most effective geophysical and geological technologies for the most productive development of the Eagle Ford shale.

Ultimately, the pursuit of Eagle Ford acreage and the designing of an Eagle Ford drilling campaign is best accomplished through a comprehensive understanding of the geological framework coupled with a focused processing, analysis and interpretation of the seismic and microseismic data. Multi-disciplinary integration is key to understanding the risks associated with this complex play. Technical partnerships like the Matador Resources–Global Geophysical Services (Weinman GeoScience) effort permit the shale operators to better position themselves in a rapidly changing play like the Eagle Ford.