CHALLENGE
Improve fracture stimulation of the Eagle Ford carbonate section by developing a better understanding of both the natural fractures and matrix.

SOLUTION
Run one toolstring combining the FMI* formation microimager to locate natural fractures and determine their density, approximate apertures, and direction; Sonic Scanner* acoustic scanning platform to verify maximum stress direction and estimate open aperture volume away from the wellbore from vertical Stoneley wave data; and CMR-Plus* combinable magnetic resonance tool to locate the highest pore volume of oil unbiased by the matrix, including the generally misleading organic content.

RESULTS
Isolated 17 stages in the lateral for targeted hydraulic fracturing and achieved 30-day average oil production of 630 bbl/d, exceeding offset wells by 30%–50%.

Understanding Eagle Ford fractures and carbonate matrix
To intersect the maximum number of natural fractures and effectively stimulate oil-bearing zones in the fractured Eagle Ford carbonate section, an operator needed a better understanding of both the existing fractures and the matrix rock. The direction of the natural fractures needed to be determined, along with their status: open or healed. Imaging alone was insufficient for fully characterizing the fractures, and conventional logging was adversely affected by the low porosity and high organic content of the matrix.

Combining images, Stoneley waves, and magnetic resonance
Wellbore imaging by the FMI imager was used to determine the directions of the natural fractures. For information on the condition of the fractures away from the wellbore, Stoneley wave data was obtained with the Sonic Scanner acoustic scanning platform. The Stoneley data clearly indicates that the natural fractures are open, which makes them good candidates for assisting production through treatment. The fast shear direction shows that induced fractures will follow the same direction as the natural fractures.

Correctly designing the fracture treatment also depended on accurate porosity and fluids evaluation. The proven CMR-Plus magnetic resonance tool was used to identify porosity in oil-bearing rock independent of the rock type, which had biased conventional measurements.

Successfully producing oil at 630 bbl/d
Based on the stress analysis, a lateral was positioned to both take advantage of the existing natural fracture system and maximize contact with potential reservoir sections, as determined from CMR-Plus tool’s porosity and fluid content. Swell packers were used to isolate 17 stages in the lateral for hydraulic fracturing. Because the optimal height of each targeted interval was determined from the log data, the pump size necessary was only about half of that used on neighboring wells. This successful completion achieved a 30-day average oil production of 630 bbl/d, exceeding offset wells in a frequently drilled area by 30% to 50%.

The Sonic Scanner platform’s multiple monopole and dipole transmitters produce compressional, shear, and Stoneley waveforms of unprecedented quality for advanced processing of slowness values.
CASE STUDY: Fracture evaluation delivers 630-bbl/d oil, Eagle Ford carbonate section

A combined log analysis of three different measurements was used to design successful placement and fracture stimulation of a lateral. The Sonic Scanner platform’s fast shear azimuth curve in Track 2 matches the fracture azimuth from the FMI formation microimager in Track 10, which is shown in enlarged view to the right of the track. Fracture aperture and density from the image log are displayed in Track 5. The permeability curve based on Sonic Scanner platform’s Stoneley waveform analysis is displayed in blue in Track 6. The red curve in Track 6 shows false Stoneley events resulting from abrupt changes in lithology and washouts. Usually not displayed, these events are not included in processing. Track 8 is a modeled waveform displayed as a Variable Density* log (VDL) based on expected Stoneley responses from the abrupt changes in lithology (similarly shown in the acoustic impedance) and borehole rugosity. This modeled waveform can be compared with the recorded waveform in Track 7. Reflection and transmission coefficients from the modeled waveform are subtracted from those computed from the recorded waveform to compute the Stoneley permeability. The mineral volumes computed from magnetic resonance, Platform Express* integrated wireline logging tool, and ECS* elemental capture spectroscopy sonde are displayed in Track 9, with the oil volume in green. The enlarged view from the FMI microimager on the right shows the target for the lateral. The target was chosen to maximize the natural fractures and computed oil volumes. The green enlarged VDL display on the right side of the enlarged fracture image is produced from the magnetic resonance every 7 in and clearly indicates late time decay in the target zone.