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Finding what others missed

Reprocessing seismic data with new techniques helps identify bypassed pay.

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In many mature fields, companies recognize the difficulty in determining potential for recovering additional hydrocarbons. As a result, these fields may subsequently be abandoned or sold rather than expending further time or expense toward keeping the fields viable.

However, the utilization of reprocessed existing seismic data, high-frequency imaging (HFI) and amplitude vs. offset (AVO) products continues to be successful in identifying bypassed pay in these older fields. A prime example that focuses on these relatively new reservoir characterization tools occurred in the **Lake Pelto** field near New Orleans, where 300 wells offshore Terrebonne Parish had produced 122 million bbl of oil and 450 of Bcf gas since the field's discovery in 1929.

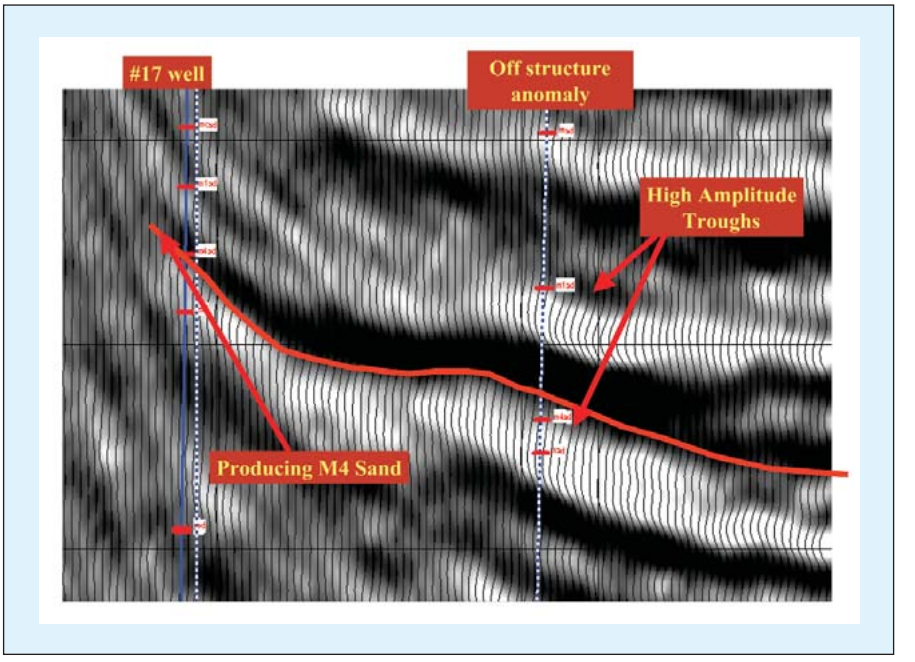

Figure 1. *Prestack time migration was helpful in positioning reflectors. (All images courtesy of Geotrace)*

The mature field

The field lies in 10 ft (3 m) of the state waters of Terrebonne Parish. Depositional environments range from inner to middle shelf to outer shelf and upper slope. The oil and gas accumulations are associated with structural and stratigraphic traps. The wells produce from Upper Miocene in the M, R and J sands. Depths range from 12,000 ft to 17,000 ft (3,660 m to 5,185 m).

Beginning in 1998, when leases and production were purchased by a Houston-based company, additional successful wells have been drilled in the Lake Pelto field and here established some 44 Bcf of new reserves.

Old seismic — new proprietary tools

Because new seismic is not required for making enhanced interpretations, to proceed with ongoing field development the new field owner's geoscientists analyzed 3-D data from the early 1990s. In turn, they determined that not just one but various areas had not been optimally exploited, and their focus then narrowed to the two most promising areas. One was immediately north of current production and the other, addressed by this article, was to the east.

At the outset, some unanticipated considerations emerged — there was no separation, structurally or stratigraphically, between producing wells and the prospect, and no trapping mechanism, which led the geoscientists to believe there would be drainage area issues. Geoscientists decided that, in using 3-D seismic for improved subsurface imaging, they should concentrate on direct hydrocarbon indicators (DHIs).

While conventional dip moveout (DMO) datasets did show high-amplitude events, possible reservoirs could not be determined or laterally mapped. Prestack Kirchhoff time migration was used to focus deep reflectors and properly position them spatially (Figure 1). Much of Louisiana production is from generally thin, stacked sequences, making seismic resolution critical to success in pinpointing bypassed pay.

Therefore, applying HFI became the most appropriate approach to obtaining the most relevant information. After reprocessing, seismic data in the area was limited to 40 Hz to 50 Hz of usable frequency, but good correlation at well locations between the data and the synthetic seismogram at normal frequency showed the data quality was good enough to have successful frequency enhancement. A narrow band trace contains higher frequency information than an extracted wavelet would suggest; high-frequency information is encoded in the low-frequency trace.

Conventional methods of trying to regain the high frequencies have been successful at achieving a flat amplitude spectrum, but the upper end of that spectrum is dominated by noise. HFI, rather than using polynomial or scalar arithmetic to recover the high end of the spectrum, transforms the seismic trace into a vector space, determines the

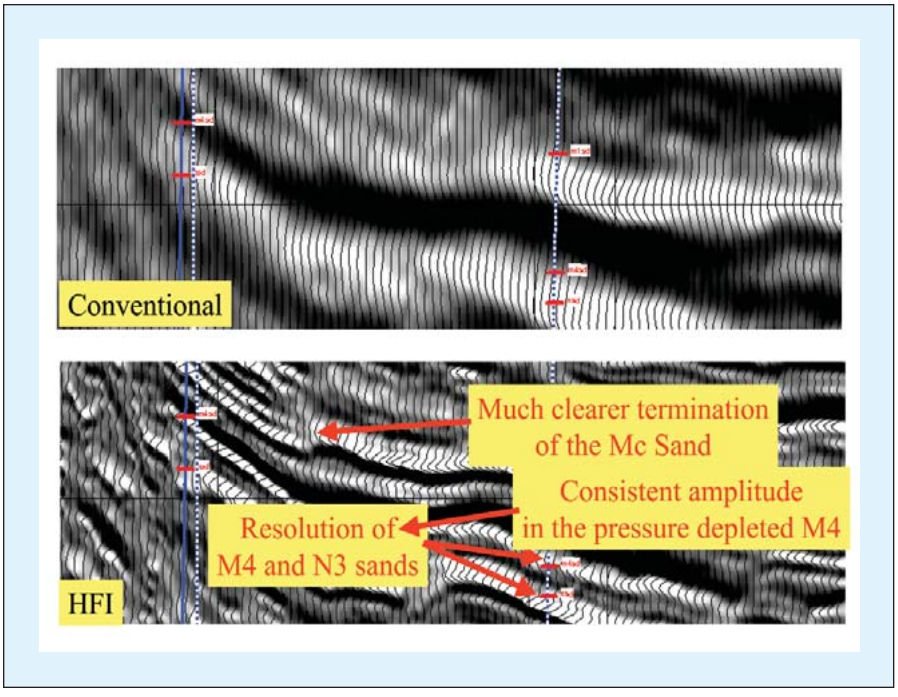

Figure 2. The reprocessed data showed a much clearer picture of the stratigraphy of the field.

location of the trace vector (in the low-frequency region), and rotates it toward a white spectral position. The ambient noise, if it is approximately flat in the lower end of the usable spectrum, exists as a sphere centered at the origin in the vector space.

As the trace vector is rotated toward higher-frequency axes, the noise also rotates as a sphere and does not increase in magnitude as the rotation occurs. The signal portion of the trace vector has increased magnitudes on higher-frequency axes, while the noise remains constant. As a consequence, the signal emerges from beneath the noise level and the high frequencies recovered are usable signal. Also, the frequencies recovered are not necessarily limited to the observable bandwidth of the input data. Since the entire spectrum is encoded in the seismic wavelet, it is possible to regain frequencies up to the Nyquist frequency on properly recorded and processed data.

In the Lake Pelto case, the HFI yielded 110 Hz on the high end. From the perspective of maximizing the quality of the end result, in practical terms this meant that beds as thin as 30 ft (10 m) could be resolved.

HFI also clearly showed the stratigraphic trapping component of the downdip accumulations as well as a small fault separating the prospect from earlier wells, neither of which had been previously observable.

After HFI was conducted on migrated gathers, high-frequency attributes were calculated on the resulting seismic volume. Well analysis indicated that producing sands were Class II or III. Therefore, the AVO effect was a high-amplitude trough at the producing sand. Another tool for Class II or III sands is the Intercept X Gradient attribute. This attribute showed a good anomaly in the downdip prospect but not in the depleted sand.

Geotrace's Frequency Absorption Reponse (FAR) effects in the broadband data were also analyzed. Gas sands are very good absorbers and will produce an anomaly. When using frequency absorption, high-frequency data is preferred because the absorption effects are much more apparent in the higher frequencies. For example, there was strong stratigraphic trapping in downdip accumulations, and gas was most likely the hydrocarbon. DHIs indicated that pay potentially existed in the upper sand zone instead of the lower M4, and it indicated the significance of a small fault separation.

Results and conclusions

Geoscientists interpreted the combination of HFI data, AVO and FAR and concluded that there were several very good probabilities for bypassed pay in this area. Based on these conclusions, the company made the decision to drill, and they made the completion as a producing gas well at 17,000 ft.

In completing this well, several points from the seismic reprocessing were confirmed, including that the uppermost 50 ft (15 m) of sand was gas-bearing, M1 sand was also present and depleted sand was there, with similar characteristics to **Well 17's** M4 sand (Figure 2). Initial flow rate was 4 MMcfgd, subsequently increasing to 8 MMcfg and 500 bbl/day of oil.

In evaluating results on this particular prospect in the Pelto field, the "lessons learned" were essentially as anticipated when deciding to employ the proprietary HFI and AVO — a much more precise, finely tuned view of the subsurface than previously yielded by conventional seismic data. Consequently, that meant then, and in the future, companies face lower risk in deciding on whether or not to drill a prospect by utilizing HFI and AVO.

One of the most significant findings involved the Mc and M1 sands. Specifically, although they did correlate between the updip wells and the downdip, stratigraphically the sand bodies in between were actually separate and distinct. Other premises were validated such as the existence of strong trapping and a small fault across the Mc and M1 sand interval. Other confirmations were that AVO accurately predicted gas accumulation and that FAR helped validate that this particular accumulation was a new, untapped reservoir.

Ultimately, the overriding conclusion was that conventional seismic would not have successfully located this bypassed pay. E&P