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The Use of Immersive 3D Technology and Acoustic Impedance Inversion to Drive Real-time Geosteering of a Horizontal Well

Abstract

The following presentation is a methodology for improving the success rate, drilling economics, and production potential of Gulf of Mexico shallow Miocene gas plays. This is achieved by converting high-resolution seismic data into acoustic impedance inversion images that are used to predict reservoir quality and fluid content. The inverted images allow optimization of borehole positioning within the reservoir and horizontal linking of multiple pay zones. This optimization helps improve the maximum rate and estimated ultimate recovery of the well. The seismic imaging, together with logging-while-drilling (LWD) data, are presented in an immersive three-dimensional (3D) environment to accomplish "real-time" borehole guidance. This scenario greatly reduces "hunting" for pay, thus reducing borehole steering, with the commensurate reduction in drilling time and cost. The immersive 3D environment is required to provide real-time borehole data, downloaded via satellite from the rig, in a 3D format. These data facilitate rapid team collaboration and decision-making based on real-time integration of engineering, geologic, petrophysical, and seismic information. The conventional rig to office to workroom to rig decision-making loop cannot support interactive guidance at the 100-ft/hr to 600-ft/hr drilling rates that are achieved in these shallow Miocene reservoirs.

Seismic Data

Shallow Miocene sands have been exploited in the Gulf of Mexico for more than three decades with widely varying results. Much of the variability in the play stems from poor definition of these complex sand reservoirs caused by the use of conventional seismic data designed for imaging deeper objectives. Many of the Miocene pays lie within the zone where mute geometry, normal moveout (NMO) stretch, and low-folding adversely affect imaging and amplitude response. In addition, the pays generally range from 10 to 30 ft in thickness, which places them at or below resolution, and in the tuning range of conventional seismic data. In this study we used a relatively small volume source and smaller sample interval to generate seismic volumes with a maximum usable frequency response in excess of 80 Hz. These data display excellent coherency and amplitude stability at the level of the targets. The data clearly define the reservoir sands, gas pay thickness, gas/water contacts, facies variations, and microstructure within the reservoirs.

The conventional seismic amplitude images are inverted to the acoustic impedance domain to facilitate calibration with borehole data and to improve interpretability. This is accomplished by employing a type of deterministic inversion that allows the removal of wavelet-related artifacts, including tuning, and produces zero-phase data for accurate determination of the aerial extent of targets and accurate computation of time/depth relationships. The low-frequency component of the acoustic impedance response is computed from borehole data and added to the seismically derived relative impedance. The resultant data volume is calibrated against borehole information to establish acoustic impedance values defining shale, water-saturated sand, and gas-saturated sand.

Two wells are used for calibration of the seismic data. Each well is logged for sonic and density information, and the logs are environmentally corrected to improve compensation for borehole rugosity and washouts. Where necessary, the sonic log is edited using a spike filter and regression against the resistivity, gamma ray, and neutron logs. Both wells contain wet and gas-filled Miocene sands, which allows the computation of pay cutoffs.

A three-dimensional visualization tool uses the cutoffs to image prospective pay bodies. To eliminate background noise the only bodies displayed have acoustic impedance values less than or equal to the maximum pay cutoff and also meet a requirement to be composed of a significant number of interconnected pixels. The visualizer and conventional workstation displays are used to select a borehole path that is approximately perpendicular to the strike of the largest reservoirs imaged in the area (Fig. 1). The criteria for the path selection links pay zones to achieve the maximum recoverable gas volume with the minimum number of linked zones. Additionally, the criteria seek to minimize the possibility of vertical as well as lateral water encroachment in the penetrated reservoirs.

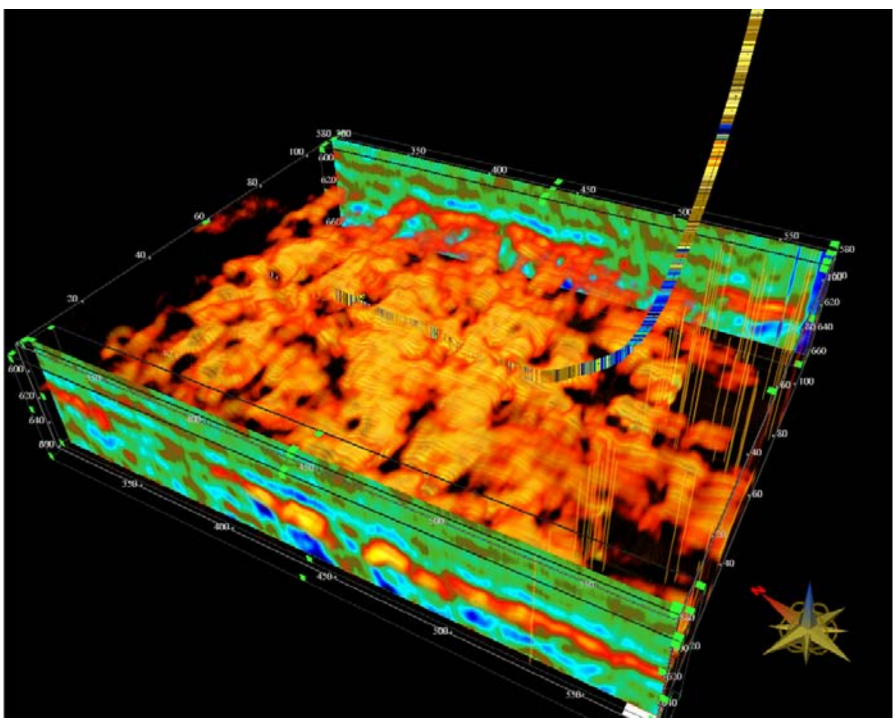

Figure 1 – Yellow to orange areas represent pay. Transparent, green, and blue areas denote shale and silts.

Drilling Operations

A pilot hole is specified in the drilling program. Its function is to provide final calibration of time/depth relationships and fine tune the acoustic impedance and pay cutoff relationships. The pilot hole entered the pay with a 0.3% total depth error, and log data indicated pay at an acoustic impedance value within 2% of the predicted value. Despite the high level of accuracy in the pre-drilling definition of the pay, it remains necessary to combine LWD data from the borehole with inversion imaging to conduct real-time adjustment of the path to compensate for unresolved shale breaks, local facies variations, and microstructure. The first few hundred feet of the borehole is critical in determining the precise relationship of the inversion signature to the actual rock properties and fluid content. The use of a 3D immersive environment greatly facilitates the accomplishment of these correlations and enables more accurate control of the borehole trajectory.

The high porosity and lack of consolidation characteristic of the target sands produce gravity related steering problems. To minimize these problems, weight is applied to the bit to keep it from dropping. The required weight results in rates of penetration ranging from about 100 ft/hr to 600 ft/hr. The complexity of the targets and the fast rate of penetration make the use of real-time technology and an immersive 3D environment mandatory to keep pace with the rapid progress of the well. The drilling equipment includes an instrumented mud motor for steering and to provide inclination, resistivity, and gamma ray data close to the bit. Behind the motor is an imaging resistivity tool to detect the formation boundaries and internal structure of the reservoir.

After completion of the pilot hole the well was sidetracked and casing set at 90° inclination at the top of a high-resistivity sand (Fig. 2, point 1). The casing shoe was drilled out, and unexpectedly low resistivity values were encountered. The decision was made to deviate from the preplanned trajectory and to drop the path in search of a better zone (Fig 2., points 2–3). After a thin shale break was traversed, resistivity values increased to 100 ohm-m and the bit was allowed to drift lower while proximity logs were used to maintain the in-pay path in what was thought to be the first pay zone based on measurement-while-drilling (MWD) logs and the drilling history since penetration of the target (Fig. 2, points 3–4). The team's reassessment of the inversion imaging in conjunction with the MWD logs in the immersive 3D environment quickly indicated that the primary pay zone had been completely penetrated in an area of localized thin sand layers and that a shale break, prominent hundreds of feet to the northwest, extended into the landing zone as a thin layer at the threshold of seismic resolution. The collaborative assessment was that the bit was 15–17 ft below the top of the primary pay and descending through a gas-charged lower sand layer that contained a water leg about 10 ft below the borehole.

Despite the indication of good pay, the decision was made to raise the path at the maximum advisable rate (Fig. 2, points 4–5). The bit was in shale for about 210 ft as it climbed at 5 ft true vertical depth (TVD) per 100 ft measured depth (MD) through the 5- to 7-ft-thick shale layer, which rose in the direction of the borehole path with a regional dip of about 2°. At 3,850 ft MD the bit reentered the bar sand complex constituting the primary pay zone and drilled in poorly consolidated sand with resistivity values consistently in excess of 100 ohm-m (Fig. 2, points 5–6) for the next 800 ft. The team working in the immersive 3D environment projected the measured depth at which the bit would exit the primary pay sand and enter a shale-filled channel to within a few feet (Fig. 2, points 6–7).

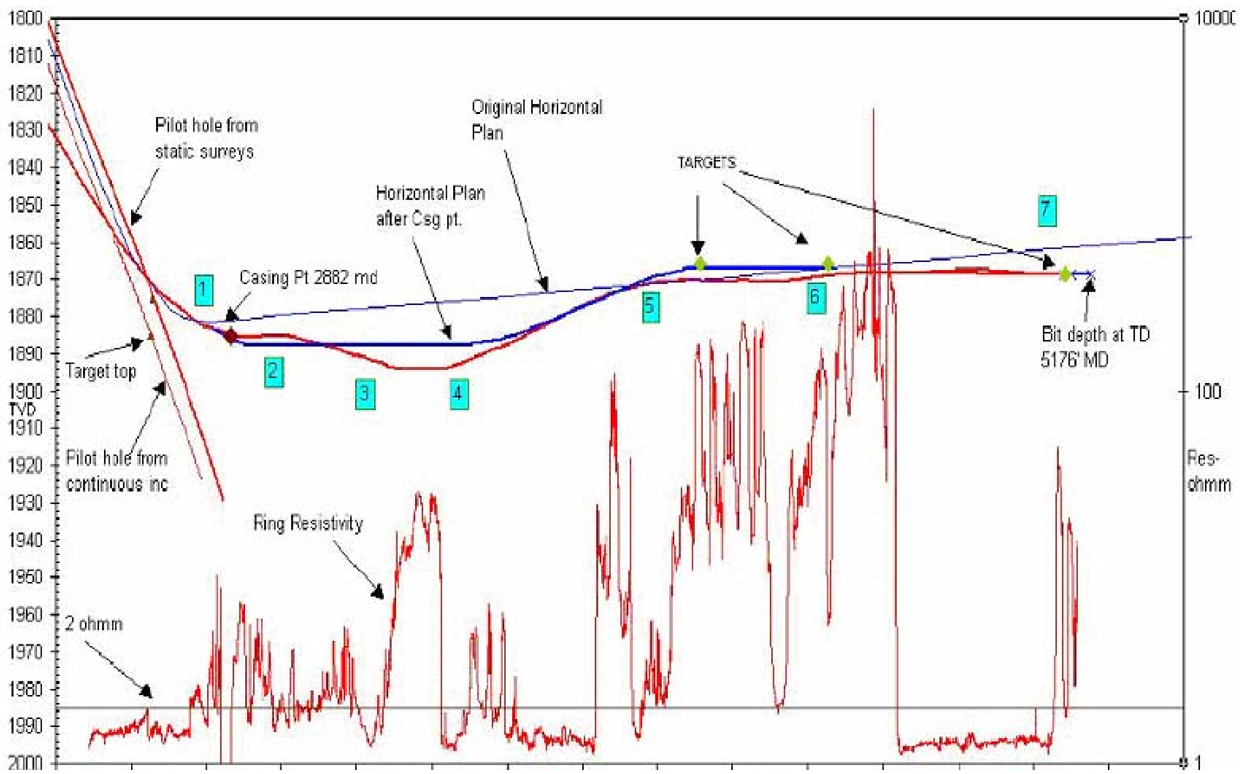

Figure 2 – Vertical section showing the well trajectory with labeled points of interest and the resistivity values along the well trajectory.

Point 1: Landing point into the reservoir
Point 2: Drilling out of the casing point
Point 3: Resistivity increase after penetrating the gas-charged reservoir
Point 4: Change in inclination to reach the second sand body
Point 5: Bit reentering the gas-charged sand (second sand body)
Point 6: Bit reentering the gas-charged sand (third sand body)
Point 7: Bit hits the final target

Further evaluation of the seismic and MWD log data against the inversion imaging suggested adjustment of the well trajectory. The well plan was recalculated and drilling continued, while building azimuth, to optimize penetration of the last bar sand (Fig. 3). This sand was entered at 5,080 ft MD, within a few feet of the predicted location. Drilling stopped, because of engineering constraints, at a total depth (TD) of 5,176 ft MD after penetrating 60 ft of the final target.

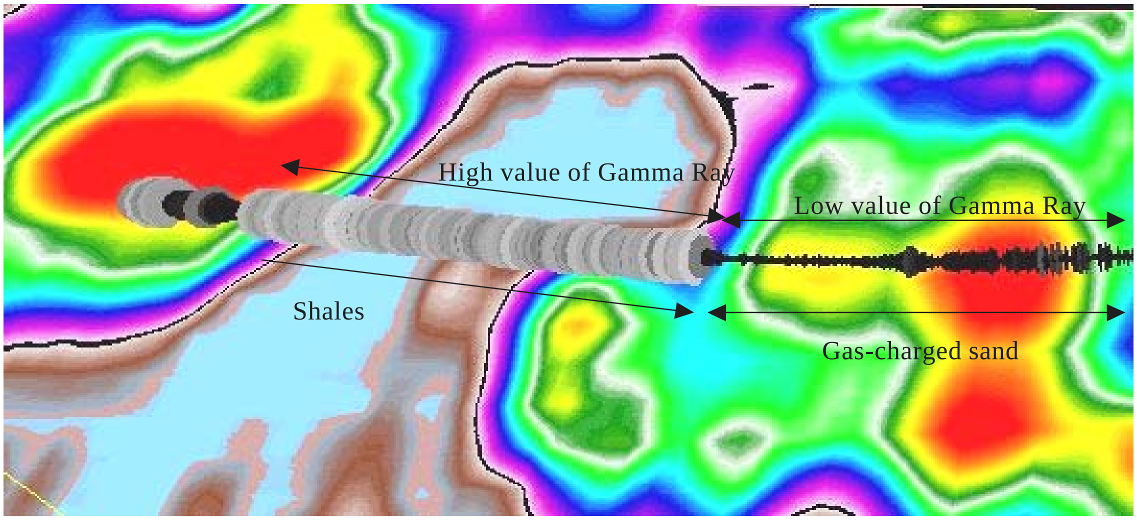

Figure 3 – Screen capture from 3D visualizer in map view showing the well and inverted seismic images. The nonproductive areas are displayed with colors ranging from light blue to black. The productive sands are displayed with colors ranging from red to purple, with red the best-quality reservoir. The gamma ray displayed along the well trajectory ties very well with the seismic information. The size of the discs is proportional to the value of the gamma ray (i.e., the higher the value of the gamma ray, the bigger the disc).

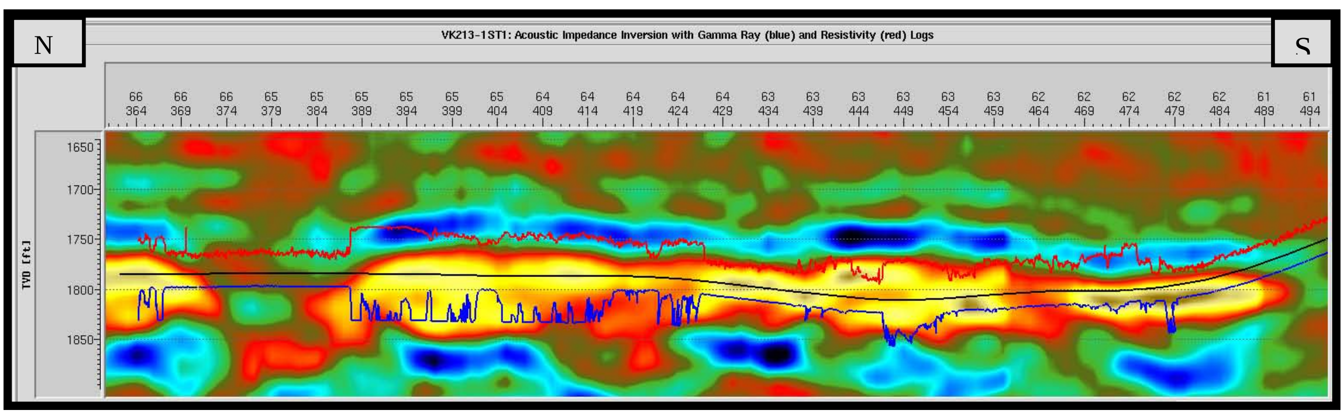

Figure 4 – Cross-sectional view along trace of borehole showing gamma ray (red) and resistivity (blue) logs superimposed on the seismic acoustic impedance inversion images.

Summary

The well most likely would have prematurely encountered water and required a costly sidetrack if high-resolution inversion imaging combined in an integrated, real-time environment with MWD/LWD logs had not been used. The high drilling rates required to efficiently traverse the targeted formation necessitate a level of rapid decision-making that is facilitated by the immersive 3D environment. The well was flow tested at 10 MMcfe/D with minimal pressure drawdown, and as shown in Figs. 2 and 4 has more than 1,100 ft of gas sand open to the production screen out of its 2,300 ft of lateral track.