Work Flow Integration, Technology Optimize Well Placements in Unconventional Plays

New techniques help operators make better decisions more quickly.

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Horizontal drilling is a critical component of successful asset development in unconventional oil and gas plays. A common misgiving in the preparation of new horizontal well plans is that work flows that have given results in the past may not be appropriate and sufficient to pick the trajectory offering the best pay per foot drilled. Recent developments in reservoir characterization and visualization technologies, coupled with high-efficiency data integration, offer game-changing opportunities to make more informed decisions in less time.

Predicting the production of planned wells based on information from prior drilling is an excellent process to follow, providing all relevant data is brought into the process in an integrated manner and not just using an interpolation of a few reservoir characteristics such as porosity, permeability, thickness, and fracture orientation. Such an overly simplistic approach can lead to unexpected outcomes because it does not take into account localized anomalies, reservoir heterogeneities, the effects of surrounding formations, or variations in the intra-formation fracture system.

As an example, in the unconventional shale plays in the continental US, the focus is on sustaining or increasing production flows through intense horizontal drilling and hydraulic fracturing activity. The work flows to plan these wells are geared towards a fast turnaround time with the use of conventional software tools. Typically they involve four steps: 1) use of seismic information to locate the seismic horizons associated to the reservoir, 2) integration of the seismic into the geological interpretation, 3) integration of the micro-seismic to define preferential stress directions, and 4) integrated real-time monitoring of the horizontal drilling with interactive correction of the deviation.

In the specific case of unconventional shale reservoirs, water saturation, hydrocarbon content, rock properties, in situ stress fields, and geohazards such as karsts or existing fractures, combined with the microseismic data linked to the hydraulic fracturing, need to be evaluated and calibrated against each other. Then an integrated visualization into a single window will lead to a holistic decision process to efficiently evaluate productive vs. nonproductive zones. No matter what their merits are, wireline log data, image logs, new rich-azimuth 3-D data seismic acquisition, or micro-seismic only bring a partial answer and need to be calibrated.

Gas shales

In the gas shale reservoirs, determination of the mineralogy and fluids content is a mandatory step in a full petrophysical process; intervals with higher quartz contents are more adapted for fracture stimulation than zones with a higher limestone and clay content. Consequently, there is a need to understand the spatial distribution of minerals away from the boreholes. This particular challenge can be solved using the proven seismic facies-supervised classification process, through which the true relation between seismic attributes and well information will help calibrate the seismic response and discriminate it as a function of mineral types. This result can be integrated into the 3-D geological model to constrain the lithofacies interpolation.

Another characteristic of such reservoirs is the presence of natural fractures or collapse chimneys from underlying formation (karsts) and associated fractures. An example is the Barnett shale formation that lies on top of the Ellenberger water-bearing carbonate formation. In such a reservoir, the combination of fractures and intrusive karst chimneys from the underlying layer is a risk when drilling a new well. Such a complex geological environment cannot be predicted using well-to-well interpolation.

Recently the industry has increased the use of wide- and rich-azimuth seismic data, and the innovative technology included in Paradigm EarthStudy 360 has helped, in the Barnett shale notably, to extract high-resolution data and information related to subsurface angle-related reflectivity.

Three-D seismic data helps delineate sweet spots and identify zones of non-interest, or “dead zones,” through a combination of seismic inversion (formation thickness and elastic properties), anisotropy determination derived from full-azimuth work flows as a stress indicator, and classification procedures such as facies indicators.

Designing wells within a 3-D structural model, which integrates all relevant features, can shorten well planning cycle times, improve well placement, and reduce drilling risk.