Good well paths need geology

To find the best well path, you need to know about the geological setting – not just about porosity, permeability and thickness, writes Bruno de Ribet, technology director Americas, Paradigm

Horizontal drilling is a critical component of successful asset development in unconventional oil and gas plays and complex stratigraphic-controlled reservoirs.

A common misgiving in the preparation of horizontal well plans is that workflows that have given results in the past are appropriate and sufficient.

Another common mistake is to pick the trajectory offering the best pay per foot drilled and therefore optimal return on investment.

Recent developments in reservoir characterization technologies and visualization capabilities, coupled to new high-efficiency data integration, offer opportunities to better understand the target formation and 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 however that 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 and thickness. Such an overly simplistic approach can lead to unexpected outcomes, and in some cases borehole failure, because it does not take into account localized anomalies, reservoir heterogeneities, the effects of surrounding formations or intra-formation fractures.

Petrophysical analysis, the geological setting, geophysical information, rocks mechanics, among others, should be considered when defining an extended integrated workflow.

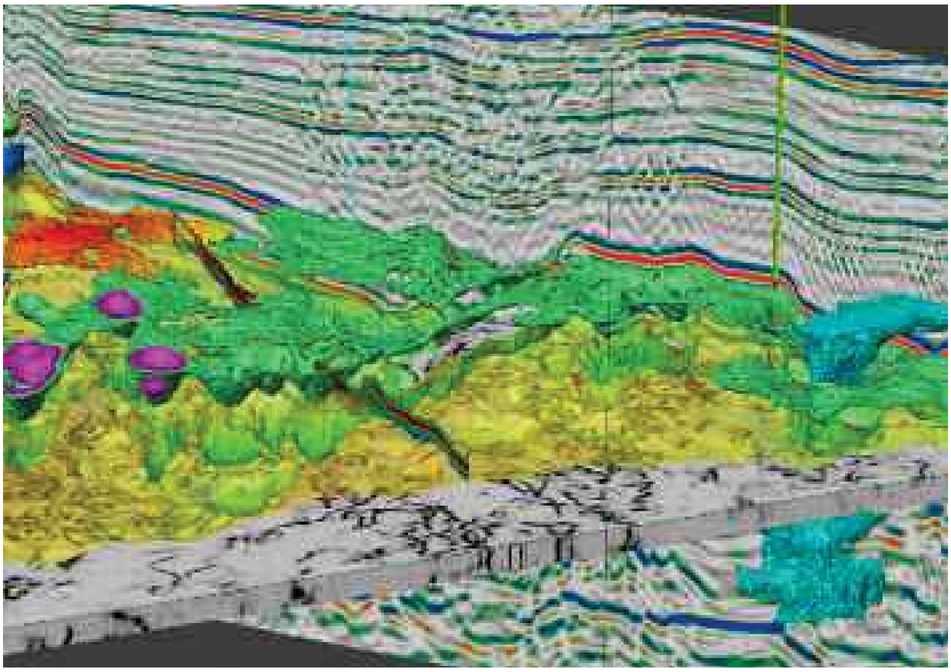

Figure1: Integrated visualization of interpretation (structural, karst chimneys, sweet-spot) from the Barnett Shale

US shale

As an example, if we look at common practices in the unconventional shale plays in the Continental United States, the focus is on sustaining or increasing production flows through intense horizontal drilling and hydraulic fracturing activity.

In many cases the workflows to plan these wells are geared towards a fast turnaround time with the use of conventional software tools to get the results.

Typically it involves 4 steps:

1) Use of seismic information to locate quickly the seismic horizons associated to the reservoir,

2) Integration of the seismic into the geological interpretation

3) Integration of the microseismic to define the preferential stress directions

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, geohazards such as karsts or existing fractures, combined with the microseismic data linked to the hydraulic fracturing, need to be evaluated and calibrated each against the others.

Then an integrated visualization into a single window (Figure I) will lead to an “across disciplines” decision process, in order to efficiently evaluate productive vs. non-productive zones.

Different sources of data

No matter what their merits are, wireline log data, image logs, new rich-azimuth 3-D data seismic acquisition or microseismic each only bring a partial answer and need to be calibrated.

In the gas shale reservoirs, determination of the mineralogy and fluids content is a mandatory step in a full petrophysical process, considering that intervals with higher quartz contents are generally more adapted for fracture stimulation than zones with a higher limestone and clay content.

The development of such reservoirs is directly associated to the induced creation of permeability using hydraulic fracture, which depends in turn upon the brittle or ductile characteristics of the reservoir rocks.

Even though we consider shale as a ductile rock by its very nature, the differences in mineralogical components will have an impact on the efficiency of hydraulic fracture.

Consequently, there is a need to understand the spatial distribution of both types of minerals away from the boreholes.

The question is which technology can support such an approach and help us complete the 3D geological mapping of the reservoir?

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 3D geological model to constrain the lithofacies interpolation, and it can also be used as an external trend in a geostatistical approach.

Fractures

Another characteristic of such reservoirs is the presence of natural fractures, or collapse chimneys from underlying formation (karsts) and associated fractures. Both represent the highest level of risk for well planning.

They can have a major impact on the completion and productivity, as they can connect two formations with distinct fluid content and could thus impact drilling plans or ruin on-going well drilling.

A well-known example is the Barnett Shale (USA) Formation that lies on the top of the Ellenberger water-bearing carbonate formation.

In such a reservoir, the combination of fractures and impressive intrusive karst chimneys from the underlying layer is a risk when drilling a new well. Such a complex geological environment cannot be predicted from well to well by interpolation.

The existence of natural fractures may represent an advantage at the initial stage and would allow a lower hydraulic effort for fracturing the source rocks.

A calibrated definition of the stress field, coupled with advanced techniques for interpreting 3D structures such as collapse chimneys, will definitely add valuable information to the final geological model.

Whatever characterizes the initial structural condition, this type of reservoir needs to be stimulated through the hydraulic fracture process in order to achieve viable production.

We are aware that the nature of the existing fractures (open or healed) has a non-negligible impact on the propagation of the induced fractures.

Understanding in-situ stress regimes and reservoir pressure conditions near the projected well is mandatory for the success of any hydraulic fracturing program.

The resulting microseismic information will then be another source of information to be calibrated with the seismic information in an adapted 3D visualization environment.

3D seismic data

3D seismic data is the main source of information to delineate "sweet-spots", and the opposite, zones of non interest or "dead zones".

The most obvious seismic attributes to be used are coherence or curvature, well suited for detecting fault and fractures trends in a first pass.

Some proprietary attributes such as the Eigen-based coherency, which is more sensitive to small variations, or the Fault-Enhanced or Vector Azimuth can give more detailed insights regarding the fracture direction in an integrated approach.

The result can be compared and calibrated with well information such as image logs that will confirm the main stress directions at the reservoir level.

Recently the industry has initiated the use of wide and rich azimuth seismic data in order to improve the illumination of reservoirs beneath highly complex structures or for providing high quality subsurface images that more clearly qualify reservoir compartmentalization.

Although this method seems to be more adapted to offshore challenges; innovative technology such as Paradigm EarthStudy 360 has helped, in the Barnett Shale notably, to extract high resolution data and information related to subsurface angle-related reflectivity.

This method emphasizes the continuity or discontinuity of subsurface features like faults and small scale fractures directly from the seismic data.

Admittedly, the application of such a technology requires from the operating companies a substantial level of commitment in hardware, computing infrastructure and qualified geoscientists.

The payoff however would far exceed such investments, making every well more deterministically-planned and targeted at areas where hydraulic fracturing will deliver the best production flows.

Interpreting seismic attributes is more challenging in such geological environments. To make it feasible within the tight time constraints of resource play operations, it is essential to work in an enhanced 3D visualization window, applying "unconventional" interpretation workflows and technologies.

This makes it possible to integrate all the available information in a single 3D environment, to map the maximum stress direction, to extrapolate the microseismic into a 3D volume referencing the magnitude and direction of propagation, and to interpret the karsts as 3D wrap surfaces.

Significant time savings can be gained in the visualization phase of the workflow by leveraging the latest generation of graphic cards: they have enough on-board memory to accommodate gigabytes of seismic and to process them on the fly.

Figure 2 shows how the quality of the image has been improved when visualizing karst chimneys.

The clearer rendering guides the geoscientist directly to a more precise characterization of the reservoir and the related spatial delineation of the "sweet-spot".

Controlling drilling risk is a high priority and 3D visualization helps to identify and mitigate potential threats that drilling engineers may encounter, by aggregating all the information in a single 3D canvas.

The challenge of producing hydrocarbons economically from increasingly complex unconventional reservoirs drives the need for well path and engineering design optimization at every stage of the planning and drilling process.

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

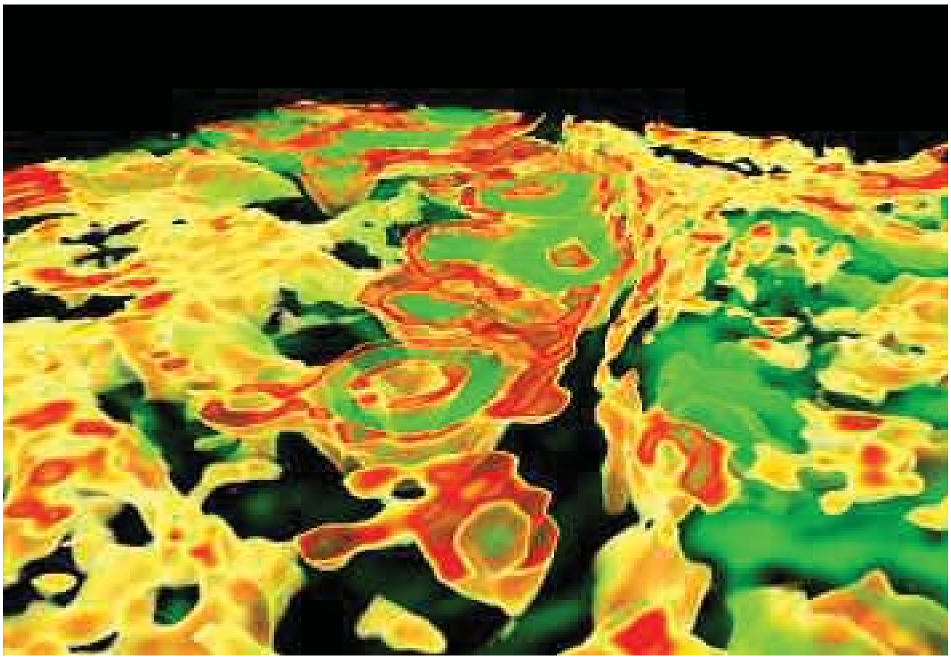

Figure 2: High quality image from the karst chimneys (Barnett Shale) obtained on new graphic card-based rendering technology