The number of oil and gas wells drilled horizontally continues to increase as operators strive to maximize contact with target formations, develop more-efficient completion programs and optimize recovery from complex geologic structures.

Structural steering, a method by which operators direct horizontal and high-angle wellbore trajectories, integrates data from deep-reading LWD resistivity tools and high-resolution imaging devices to create structural models of the geologic conditions encountered by the drill bit. This technique allows drillers to correct wellbore trajectories in anticipation of structural changes ahead of the bit and helps operators better understand the formations already drilled.
Horizontal drilling before 1985. In 1986, only 41 wells worldwide were classified as horizontal. A dramatic increase in these numbers occurred between 1989 and 1990, driven by technological improvements and by the resultant increases in production experienced by some operators drilling horizontal wells. Although at the outset the trend was primarily in the US, operators in other regions, especially Canada, also drilled more horizontal wells. (Adapted from Kuchuk et al, reference 5.)
Some experts have attributed the global growth in horizontal drilling to the successes and lessons learned in these and other Texas wells. However, not all horizontal wells drilled in the Austin Chalk formation experienced dramatic increases in production. Many operators failed to take into account the complex nature of the formation, which included compartmentalization and subseismic faults that divided the Austin Chalk into multiple isolated reservoirs.

Today, operators use extensive reservoir models to extrapolate surface and downhole data and predict the formations that horizontal wells will encounter. This approach attempts to identify rock of better reservoir quality, and where applicable, of better completion quality. However, until a well is drilled, the model, which is a function of the type and quality of available data, remains an approximation.

Well Placement Methods

Downhole hardware for drilling horizontal wells has improved considerably over the past decades, and well placement methodologies and workflows have been developed to capitalize on new technologies and drilling techniques. With these improvements, well placement methods continue to evolve. Today, three complementary methods are generally used in well placement. The first method is characterized as model, compare and update and is a reactive drilling process. The second relies on estimating and extrapolating the orientation of bedding planes from formation dip data, usually with azimuthal measurements acquired while drilling. The third method relies on deep-reading directional data for remote boundary detection to proactively adjust the wellbore trajectory to maximize reservoir contact and avoid exiting target zones.

In the model, compare and update method, the well placement team first generates a model of logging tool responses based on expected formations observed in offset log data (above). Seismic data interpretations are included in the analysis to help geologists estimate the location...
of formation boundaries. The team may use 3D visualization software that usually includes plan-ahead functionality to develop wellbore trajectory and drilling programs. Real-time data acquired while drilling either validate the model or are used to update it in response to the new information (left). The directional driller can then make changes in the wellbore trajectory based on the updated model.

The second well placement method requires an understanding of the orientation and magnitude of the formation dip. After interpreting azimuthal data from wellbore images, well placement engineers are able to estimate and extrapolate the orientation of the target bed or formation. The bit is steered to remain within the target. If the bit is no longer in the target reservoir layer, the LWD data can be used to determine whether the bit has exited the top or the bottom of the reservoir, and the directional drilling engineer can apply corrections to steer the bit back toward the target (below). When the wellbore crosses a fault and leaves the reservoir, this technique may not be effective because the engineer must know which direction to proceed to reconnect with the target, and azimuthal data alone may not provide that information.

In the third method, well placement engineers use remote boundary detection to proactively determine the direction in which to steer the bit. Deep azimuthal measurements give

![](image1.png)

Tracking the model. Well placement engineers and geologists may create software models of logging tool responses from anticipated subsurface geology. The gamma ray (green, top) and shallow resistivity data (blue, middle) are tracking the modeled response (red), which would indicate that the 2D model for well trajectory (bottom, green) is valid. Differences between the modeled and measured deep resistivity data (log data, bottom) may indicate that the well trajectory will need to be adjusted, although the deep resistivity data are again tracking at the current bit position.

![](image2.png)

Well placement using formation dip data. Azimuthal log data in the shapes of smiles and frowns help well placement engineers determine bit corrections. When a wellbore crosses a bedding plane, an azimuthal logging tool response indicates whether the wellbore is exiting an ascending or descending geologic layer. When the wellbore cuts an ascending layer (left), the first contact with the formation is at the bottom of the hole (bottom left); when the bit exits the layer, the last contact will be at the top of the hole. When the bit cuts an ascending layer, the data appear as a frown in the image. Conversely, measurements from a wellbore that exits a descending bedding plane appear as a smile (right). The bit can be guided up or down based on these interpretations to ensure that the wellbore remains in or reconnects with a target zone.
early warning of approaching changes in the target and surrounding layers (right). This technique works best when there is sufficient resistivity contrast between the bounding layer and the target. Drilling programs that optimize drainage, access untapped compartments and steer clear of potential water sources are some of the primary beneficiaries of this type of proactive drilling. In thick reservoir sections or in low-contrast environments, this technique may not be as effective. Complex geologic environments, such as faulting and folds, are also problematic for this technique.

Another well placement technique, structural steering, extends the capabilities of these three methods. It replaces geometric assumptions about planar surfaces with geologically informed predictions of structure based on observed well data (below right). Whereas most well placement techniques focus on geometry, structural steering uses some aspects of the traditional methodologies but attempts to resolve geologic complexities with LWD data, some of which have only recently become available in real time.

**Structural Steering Workflow**

Directional drilling is defined as the science of steering a wellbore along a planned path to a target located at a given lateral distance and direction. Structural steering, which leverages information from LWD services, is the process of combining structural analysis and modeling capabilities with borehole images to create 3D models that operators use to optimize well placement, often in real time. By incorporating geologic models created with new software tools and developing greater trust in interpretations that might not fit original drilling programs, operators are able to make real-time decisions based on structural steering methodologies.

One example of software that enables well placement by means of structural steering combines two plug-ins used in the Petrel E&P software platform: eXpandBG near-wellbore to reservoir scale modeling and the eXpandGST real-time geosteering module. Real-time data from the MicroScope resistivity- and imaging-while-drilling service can be combined with deep measurements from the PeriScope bed boundary mapper tool to provide structural analysis and modeling capabilities.

Using data from tools that provide deep-reading capabilities along with those that acquire real-time borehole images, geologists at Schlumberger have developed a structural steering workflow that provides a framework for well placement

![Distance to boundary (DTB) technology for well placement. Real-time distance to boundary mapping technology uses directional measurements and large depth of investigation (DOI) to determine the distance to adjacent layers above and below the well path. For DTB technology to be used effectively, resistivity contrasts between adjacent beds must be present, and the adjacent beds must be within the measurement window. Resistivity data from deep-reading LWD services, such as the PeriScope tool, can be inverted and the values converted to colors. Contrasting colors highlight the differences in bedding plane properties. Data are processed and presented in such a way as to give the appearance of curtains, giving rise to the name curtain display. When the well position relative to adjacent beds is known, the bit can be steered by making adjustments to the drilling assembly to point the bit in the desired direction (blue) so that the wellbore stays within target zones or returns should the trajectory exit from a target. Had the planned trajectory (green) been followed, this well would have exited the target zone (light colors).](image)

^ Structural steering for well placement. Structural steering incorporates reservoir modeling and distance to boundary technology in conjunction with high-resolution imaging to manage drilling decisions. From these data, geologists create 3D models, such as the one shown, which help directional drillers visualize the formations around and ahead of the bit. This is especially useful for predicting subsurface geometry and for guiding the bit in complex reservoirs with faults and folds.
decisions (left). The interpreter picks the distance to boundaries, and the boundaries are displayed on an eXpandG® curtain section. Image data from tools such as the MicroScope service provide bedding dip, fracture information and fault detection.

The eXpandBG module imports the LWD logging data, and engineers generate an updated model that includes drilling polarity logs. Polarity logs indicate whether the well is heading toward the bottom or toward the top of a structure. The software next computes a true stratigraphic thickness (TST) index; TST is related to the thickness of the reservoir section. Well placement engineers can compare structural dips while the drilling progresses with those in the original model and quickly identify anomalies. The software projects the structural dip away from the well using stratigraphic horizons, and the geologist can label formation tops and stratigraphic surfaces. Armed with this information, the well placement team can determine whether corrections are required and in which direction to steer.

Two crucial elements for structural drilling are LWD data that can be used to develop realistic models and software that can provide a robust solution describing the reservoir. Without real-time data, engineers and geologists may have difficulty understanding the geometry of the subsurface and accurately projecting where the next step should be taken. Unfortunately, engineers must often make decisions with insufficient data about complex reservoirs. Until recently, the tools for resolving these complexities did not exist for LWD operations, but this is no longer the case.

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Tools of the Trade

Along with modeling software and drilling hardware, LWD tools are experiencing an evolution in design and function. Originally, LWD tools replicated information available from conventional wireline logging tools, which are designed primarily to obtain high-quality petrophysical data essential for reservoir characterization. Modern LWD tools still provide petrophysical information and have the advantage that data are acquired before the formations have been exposed to drilling fluids, which over time can alter rock and fluid properties. However, the real-time aspect of LWD operations is creating a divergent path in tool development.

Service companies are introducing LWD tools that probe regions deeper in the formation than is customary with wireline tools. New tool designs also make it possible to acquire data at the bit. With a wide swath of the formation around the wellbore illuminated by these measurements, drillers can precisely position the wellbore to optimize production or injection performance.

Application of data from these new tools has the potential to fundamentally change the way directional wells are drilled. For example, well placement engineers can use information provided by deep-reading tools to help steer the well within a narrowly defined target zone. Using deep-reading measurements and TST processing, engineers can now manage the direction of wellbore trajectories based on surrounding structures rather than conditions very close to the wellbore.

For fractured reservoirs, such as the Austin Chalk and many shale plays, the reservoir section may be tens or even hundreds of meters thick, and well placement may be more focused on intersecting fracture networks than staying in a narrow zone. Imaging tools that provide high-resolution measurements can confirm the presence of fractures and perhaps lead to redirecting or redrilling wellbore sections that are not optimally placed. Conversely, to prevent early-onset water production, fracture and fault avoidance may be the objective in some reservoirs. Engineers use these same imaging tools to identify fractures and faults and to accurately characterize their orientation.

Because these measurements, especially wellbore imaging, involve large amounts of data, and LWD data transmission rates are orders of magnitude below those of wireline logging systems, the primary source for imaging data has been wireline tools. Recently, LWD data transmission systems and imaging tools have been introduced that can replicate the capabilities of wireline tools for detecting fractures and faults and determining their orientation. No longer are separate logging runs required to obtain this information, and drillers can make decisions while the drilling assembly is still in the hole.

Resolution Evolution

Most LWD tools transmit data to the surface using mud pulse telemetry (MPT). Although today, data rates are often given in megabits/s and terabits/s, mud pulse telemetry systems originally offered data rates in the single-digit bit/s (bps) range (above). Because LWD tools have the ability to continuously transmit data uphole while drilling, giving them the benefit of having more time to acquire and send data than their wireline counterparts, service companies have found ways to overcome inherently low MPT rates. However, data-intensive measurements, such as those associated with borehole imaging, were almost always performed with wireline logging tools because the logging cable offered the ability to transmit data at sufficiently high rates.

Modern LWD MPT systems transmit at higher rates—some systems can approach 128 bps. These enhanced transmission speeds, together with new methods for data compression, have opened up a new world of possibilities for real-time data acquisition. One tool that has benefited from higher data transmission capabilities is the MicroScope service (below). Acquiring data from focused azimuthal sensors while rotating,
the tool provides images of the borehole comparable to those of wireline tools such as the FMI fullbore formation microimager. An added benefit of the MicroScope tool is that it can provide high-resolution resistivity images at different radial depths of investigation, which allows engineers to distinguish natural fractures from drilling-induced fractures.

The tool uses toroidal antennas as transmitters to send axial currents along the collar and into the formation for resistivity measurements. Two electrode buttons mounted at opposite sides of the collar provide borehole coverage as the tool rotates. The current leaves the tool surface, is directed through the conductive drilling fluid into the formation and returns to the button electrodes. Once corrected for borehole effects, the measurement of current is a function of the formation conductivity (and its reciprocal, resistivity). The buttons measure azimuthal resistivity in 56 separate bins distributed around the borehole circumference, and the orientation of the button measurements is determined with respect to the Earth’s magnetic field, which is measured with an azimuthal orientation system mounted perpendicular to the tool’s axis.

The full array of measurements has depths of investigation approximately 2.5, 7.6, 13 and 15 cm [1, 3, 5 and 6 in.], measured radially outward from the tool surface. These data can resolve bedding planes and features as small as an inch. Although FMI images can resolve smaller features, which are useful for texture analysis and characterization of fractures, MicroScope image data compare favorably with FMI images (above).

A bit resistivity measurement, derived from two antennas at the bottom of the tool, is also available. One antenna acts as a transmitter and the other as a monitor. Current flows out from the bit and returns farther up the toolstring. The drillstring below the antennas acts as an electrode, and the measured current depends on the formation resistivity and mud properties.

Other than the large amount of data needed to provide images, one of the biggest challenges of producing high-resolution images using LWD tools is the conversion of time-based to depth-based data. Traditional LWD measurements are indexed to pipe movement observed at the drilling floor. This technique is not adequate for detection of small formation features because drillpipe movement at the surface may not reflect small tool movements downhole. Scientists at Schlumberger have introduced a new algorithm to derive local depth information based on tool revolutions rather than observed pipe movement.

For this technique, high-resolution data, along with magnetometer-based tool orientation, are recorded versus time. These data can be viewed as strips with a constant and known thickness. Converting the time-based measurements to a depth-indexed image requires precise estimations of the azimuthal and axial position of the sensors. As the tool advances, overlapping strips are merged and then correlated to axial tool movement. The technique provides a high-resolution depth match (next page, top). The images are then transmitted to the surface with minimal resolution degradation.

Well placement engineers also use measurements with greater depths of investigation than those of wireline logging tools to identify distances to top and bottom boundaries of reservoir sections. These measurements help engineers plan wellbore trajectories so they remain within target intervals. The PeriScope bed boundary mapper makes a 360° measurement and can detect beds as far as 6.4 m [21 ft] from the borehole. Tilted receiver coils that have directional sensitivity can determine bed orientation. As long as there is sufficient resistivity contrast between target beds and those adjacent to the zones of interest, the PeriScope tool can provide crucial information about the position of the wellbore in the formation.

Modern well placement requires more than determining the location and orientation of the bit within a target zone. If faults are encountered, well placement engineers may not have...
sufficient information from deep-reading tools alone to understand the geometry required to guide the bit back to the target. Integrating high-resolution image data with data from deep-reading tools helps geologists construct a 3D picture of the structure surrounding the wellbore and can often help directional drillers decide where to go next and how to reconnect with the reservoir if the wellbore trajectory exits the target interval (right).

Resolving Complexities

During the past decade, gas production from organic-rich shales has become a global pursuit; this phenomenon has been driven in large part by hydraulic stimulation and horizontal drilling. The conventional approach to developing these resources is to drill a vertical pilot well followed by a horizontal sidetrack targeting the shale interval. Because of the complex geologic structural settings in many of these plays, some wellbores may exit the pay zone or encounter rock with poor reservoir quality. Although seismic data are frequently used to resolve reservoir complexities, in many cases these data lack the resolution to adequately define subsurface features. A new 3D structural technique, which includes the application of eXpand™ modeling, was recently utilized in a Marcellus Shale well operated by Chief Oil & Gas LLC.¹²

Correlating high-resolution measurements to depth. LWD logging depths are referenced to pipe measurements taken at the surface. For most data, this is an acceptable acquisition method. However, the accuracy of this method is not sufficient for high-resolution measurements. To compensate for shortcomings of traditional depth measurements, engineers at Schlumberger developed a technique that uses overlapping strips from images (left) to create an internal depth reference based on known fixed distances between sensor buttons on the tool. Correlation takes into account the mismatch between tool movement downhole (middle, blue) and surface movement (black). The resulting correlated images (right) are much improved compared with the noncorrelated images. (Adapted from Borghi et al, reference 8.)

Data integration. Geologists use real-time images (top) to identify faults and determine dip direction; these data are then used to explain geologic conditions. Geologists may also use DTB measurements to help generate models of subsurface layers (bottom). The integration of these data allows directional drillers to modify planned well trajectories (green) to maximize reservoir contact and determine the optimal path (blue) to return the wellbore to the target (yellow) should the wellbore encounter unexpected conditions such as faults and folding.

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Structural Model Produced Using eXpandBG Processing

The eXpandBG approach solves for geometric complexities without the need for extensive input by the interpreter. The software can also create structural models using multiwell data for input. In this example, formation dip was computed using the local curvature axes technique to produce the eXpandBG structural model. Solutions using this technique may not be unique; however, the interpreting geologists may intervene and adjust the solution to fit with other data such as 3D seismic interpretations.

Geologists with Chief and Schlumberger analyzed dip sequences in both the pilot well and the subsequent horizontal section and classified structures using the local curvature axes technique on a Schmidt plot to resolve the structural complexity. Contrary to the original model, the new model revealed three distinct sections: an asymmetrical anticline, a highly tilted block and a third section characterized as gently tilted (above).

Based on the dips identified in the vertical well, the formation was assumed to be gently dipping to the NNW at 5°. The well was to be landed in the target interval and follow this trend. However, the lateral was actually landed at a fold axis where the structure immediately turned down to the south at 24°. The well soon exited the reservoir section and crossed a fault, eventually reconnecting with the reservoir but in a section that dipped in the opposite direction, north at 25°. The well encountered a second fault and was then back in the target formation; drilling continued along the path indicated by the original structural model. Unfortunately, because the formation was dipping more steeply than had been modeled, the well exited the bottom of the Marcellus Shale earlier than expected.

A review of the well path validates the need for real-time structural data while drilling. With only azimuthal gamma ray data available for interpreting the formation structure, the drilling program did not produce an optimal well path. Had imaging and deep resistivity data been acquired with LWD tools in real time, the resultant drilling and completion programs may have been quite different.

One final step in the modeling process involves validation with Petrel geologic reconstruction software. This suite enables restoration and forward modeling of complex folded and faulted geologic models. By simulating mechanical rock behavior with a comprehensive set of boundary conditions, the software allows the user to analyze complex structures. The software confirmed the viability of the complex present-day interpretation (next page, top). Newly acquired 3D seismic data also validated the structural model.

Production from this well was classified as disappointing compared with that in nearby wells. Had the structural model been updated using LWD images, the well path may have been modified or perhaps redrilled based on the new model. Similarly, the four-stage stimulation design may have been more effective (next page, bottom). Only Stages 2 and 3 were completely within the target zone. Stages 1 and 4 covered zones that were in the target for only half the interval. Additionally, a section of the Marcellus Shale at the heel of the well was not stimulated, although it coincides with a highly stressed interval around the fold where FMI data indicated the presence of natural fractures, which often enhance production in shale reservoirs. In this case, real-time structural data may have resulted in a well trajectory that contacted more of the target formation and led to better well production.
Steering for Storage

A structural steering workflow that did use real-time LWD data and eXpandBG processing was recently employed in an underground gas storage project carried out by Stoccaggi Gas Italia (Stogit) SpA, the gas storage division of Società Nazionale Metanodotti (Snam). The multifield, multwell project was developed with the technical contribution of Eni SpA specialists. The objective of the drilling program was to expose as much reservoir section with optimal properties as possible in the shortest well length. To that end, wells were drilled and steered using real-time LWD data.

As is the case in many areas of Italy, horizontal drilling is challenging because of steeply dipping beds, faulting and abrupt stratigraphic changes. The reservoir section of the Furci field is characterized as a limited extension Pliocene turbidite system. It includes several sand bodies with smaller interbedded laminations. The procedure for drilling wells in the field followed a predetermined workflow. The operator chose horizontal targets, and well placement engineers loaded the well plan into the eXpandGST module in the Petrel E&P software platform, which was populated with log properties from a vertical pilot well. The program created a forward modeled log to predict log responses for several scenarios such as a formation dip that was higher or lower than expected. These scenarios would indicate that the well was in a different part of the reservoir than planned.

For the second of two wells drilled in the field, the target consisted of two large sand lobes separated by two shale beds. The objective was to drill through the shallow sand lobe, cross the thin shale beds and navigate into the deeper sand lobe. The operator drilled the vertical pilot hole as planned and then began the horizontal section following the predetermined trajectory.

Geologists determined formation dips by using two independent tool systems: a deep-reading bed boundary PeriScope tool and a borehole imaging MicroScope tool. These measurements provided information about faults and bedding that cut across the borehole. As horizontal drilling commenced, the PeriScope tool indicated flat dip and then a slightly rising inclination. A sudden decrease in resistivity appeared to indicate structural balancing and restoration. To confirm the validity of an interpretation created using the eXpandBG model, structural balancing and restoration modeling must be performed. Assuming the original layer cake geometry (top), the model is exposed to postdepositional loading using Petrel geologic reconstruction software. Early-stage compression (middle) produces the complex geometry observed, and later uplift explains the present-day condition (bottom). This last modeling step validates the interpretation generated by the eXpandBG software.

Completion results. The operator designed the stimulation program for the Marcellus Shale well based on interpretation of the azimuthal gamma ray data; the program was developed before the revised structural model, shown here, was created. Of the four stages shown (magenta), only Stages 2 and 3 were wholly within the target zone. Stages 1 and 4 were only partially in the Marcellus Shale. No treatment was applied to the heel of the well (dashed white oval) where fractures were identified, which engineers viewed as a missed stimulation opportunity. The operator considered the performance of this well disappointing compared with that in offset wells.

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that the trajectory had crossed the upper lobe and the middle shale sections and was approaching the lower lobe. Instead of encountering continuous layers, the actual trajectory (blue) encountered a fault, entered an uplifted section below the target sand lobes and crossed another fault before reconnecting with the lower sand lobe in a downdropped section. After drilling through a section of the lower sand lobe, the wellbore crossed a second fault and again encountered the reservoir section. Log data acquired after crossing the second fault indicated that the well was penetrating the lower sand lobe, and the drilling team made the decision to incline the bit to more than 90° and reconnect with the upper lobe.

The well crossed back through the shale layers and eventually reached a downdropped section of the upper sand lobe. After crossing the first fault, the original well trajectory would have missed the lower lobe entirely, and a large portion of the well would have been drilled through the shale layers that separated the lobes. The updated trajectory, modified using real-time LWD data, intersected both lobes and maximized wellbore contact with the reservoir section.

Shale Drilling

In a Niobrara Shale exploration well in northeast Colorado and southeastern Wyoming, USA, engineers used the structural drilling workflow to resolve complex geologic conditions in a shale well. The Niobrara Shale play is an upper Cretaceous calcareous shale that produces oil and gas. The shales are composed of argillaceous limestones with interblended chalk, marl and bentonite. Because of the rock's low permeability and porosity, production is generally higher in zones with natural fractures enhanced by hydraulic stimulation.

The typical development scenario for Niobrara Shale wells is to drill a vertical pilot hole and acquire petrophysical data using logging tools on wireline. For evaluation wells, the logging program usually consists of resistivity, neutron and density porosity, elemental capture spectroscopy and nuclear magnetic resonance (NMR) tools. Borehole image logs are run for fracture identification and geologic characterization. Acoustic logs may be run for mechanical properties, which are used in fracture stimulation design and wellbore stability estimations. Operators often include conventional coring for the pilot wells to determine lithology and describe fractures. Data from the pilot holes are used to characterize the reservoir, define the orientation of target zones and identify the optimal depth for landing the lateral section.

Logging objectives in the horizontal section differ from those of the vertical pilot wells. Fracture population density, type and orientation are needed for stimulation design. Measuring the wellbore path and orientation are crucial, especially when the well crosses in and out of reservoir layers. Identifying faults and determining their location and orientation aid completion design. Engineers identify zones with structural complexity to help them keep the wellbore in the reservoir unit or determine the best path to reconnect if the well exits the target. Depositional variations can be determined with LWD tools, and geologists use these data to adjust models that extrapolate properties from the pilot well.

Traditional methods of acquiring image data in the lateral section require that drillpipe-conveyed wireline tools be deployed. Geologists used these data to identify the presence of natural fractures and quantify their orientation and density. However, high-resolution image data from the MicroScope tool eliminate the need for separate wireline logging runs (above).

Resolving complex geology. Image data from the MicroScope tool can be presented in dynamic (Track 2) or static (Track 4) mode. Formation dip (top, Track 1) can be handpicked from images or computed from these data. The green tadpoles indicate the down direction of the dip, 0° to 360° clockwise around each tadpole, which represents north-east-south-west-north. The magnitude of dip is also computed and can be read from the log. The magenta tadpole indicates a fracture and provides its orientation. The image data can be presented in a wrap mode that simulates the horizontal well (inset). Bedding planes (green), faults (magenta), open fractures (blue) and healed fractures (cyan) can be visualized as they appear in the horizontal wellbore. (Adapted from Koepsell et al, reference 15.)
An operator in the Denver-Julesburg basin began a campaign to develop the Niobrara formation with multistage hydraulic fracturing in horizontal wells. From the vertical pilot well logs, geologists were able to confirm the presence of a target layer known as the C bench. The image data indicated open fractures with strike populations oriented NW-SE and mineralized fractures striking NNE-SSW. To maximize intersection with the natural fractures, the horizontal well section was planned perpendicular to the natural fractures at an azimuth of 104° and with a length of approximately 2,400 ft [730 m].

The MicroScope tool provided real-time high-resolution images for structural and fracture analysis. Engineers created 3D models using eXpand® software, which helped them optimize well placement and design hydraulic stimulation operations. The MicroScope image data were particularly useful in revealing the complex structural setting. In addition to numerous open and healed fractures, geologists identified numerous faults, a missing section and structurally deformed beds (below).

The planned well trajectory, developed from pilot hole and surface seismic data, resulted in the well crossing a fault and exiting the target zone into unproductive marl sections below the target. The last half of the well was below the C bench and was drilled mostly in nonreservoir quality ductile shale. After these data were analyzed, the well was sidetracked and redrilled through most of the interval and steered higher in the structure based on the new model.

The logging results affected a number of the engineers’ decisions for the completion program for the sidetrack well. For instance, the program called for openhole packers for isolation. Engineers identified washed out and elliptical borehole sections and avoided setting packers in these zones. Packers were not set near faults, which can affect the quality of the seal as well as impact stimulation results. For similar reasons, packers were not set in open natural fractures,

Stepping out from vertical. Geologists can identify the location and orientation of bedding planes and faults in vertical wells and project them away from the wellbore, but horizontal wells often encounter unexpected geologic geometry. In this vertical well section (top), geologists identified several geologic sections, including the target reservoir C bench section, which is a mixture of chalk and marl bounded by ductile shales and unproductive chalks and is part of the Niobrara formation. Well placement engineers developed a trajectory to follow the target, and directional engineers landed the lateral well in the C bench (bottom, expanded section). Horizontal drilling proceeded for approximately 2,350 ft [716 m] and the well encountered structural geometry that differed from geologists’ expectations. The well (black) crossed at least seven major faults (magenta lines). After the first set of faults, the C bench was found to be upthrown, which positioned the well in the lowest part of the reservoir. As drilling progressed, the well crossed a fifth major fault and was below the target formation and completely out of the reservoir. After geologists developed the new model of the horizontal well, the operator pulled back to the first fault section and redrilled the horizontal section with an orientation (not shown) that carried the well above the original trajectory; this repositioning allowed the well to remain in the target interval. Geologists can also use dip data to identify other features. The stereonet plots shown across five of the intervals can be used to identify fracture and fault type and orientation. The far left plot shows the NNW by SSE orientation of healed fractures, probably resulting from folding. (Adapted from Koepsell et al, reference 15.)
which were also identified in image data. Fracture stimulations were performed in stages, and the stages were designed to target similar rock types identified from petrophysical data. Stimulation designs also included consideration of local stresses that resulted from formation structural complexity.

Drilling Between the Lines

Unconventional resources may require approaches for drilling and completions that differ from those for conventional reservoirs, but conventional reservoirs can benefit from application of unconventional solutions. Saudi Aramco used the real-time structural steering workflow with eXpand® and eXpand®-MT processing to access resources that otherwise would have been difficult to produce economically. The carbonate reservoir consisted of a thin, permeable layer sandwiched between low-permeability intervals overlain by a thick, nonporous carbonate caprock.

The well was drilled in a mature giant field located in Saudi Arabia. Historically, this field has produced mainly from two major carbonate reservoirs. In the early 1980s, two smaller stratigraphic oil accumulations were discovered. The example well was drilled in the larger of these two reservoirs. The discovery was further delineated and tested by several vertical wells. The low-permeability reservoir contains good quality light oil with a relatively high gas/oil ratio.

In early 2012, Saudi Aramco drilled the first reservoir development well, deepening an existing dead producer originally completed in the main producing horizon. The pilot hole was drilled as a 30° slanted well across the reservoir section, and Saudi Aramco carried out an extensive data acquisition program that included coring the full reservoir interval.

Porosity and resistivity in the zone of interest were fairly uniform; the operator used a CMR combinable magnetic resonance logging tool to identify the presence of movable oil (above). An MDT modular formation dynamics tester confirmed that only a thin layer within the zone had

Well placement and job execution. Within the oil-bearing carbonate zone of interest, engineers confined the target to a narrow permeable streak (bottom, yellow) bounded by lower-permeability oil-bearing layers (tan). The drilling objective was to guide the well maintaining a constant distance from the high-resistivity, low-porosity caprock (green) overlying the reservoir. Resistivity (Track 4) and porosity (not shown) data exhibited little variation across the interval. For guidance, engineers used PeriScope curtain data (Tracks 7 and 8) to maintain the DTB. Geologists also used MicroScope image data (Track 3) to detect subtle changes in orientation and formation dip (Track 2). Well placement engineers proactively corrected the well trajectory based on polarity data (Track 6, red indicates drilling up structure, green indicates drilling down structure). Because fluid mobility and permeability were the properties that differentiated the target interval from the rest of the zone of interest, an FPWD tool was included in the LWD logging suite. Mobility measurements were acquired at irregular intervals along the well (blue circles, Track 1), but after validating the presence of fluid mobility for approximately 1,700 ft [520 m], engineers removed the FPWD tool from the string because of concerns about tool sticking. The well placement team steered the well for approximately 2,900 ft [884 m] (bottom, blue) and stayed within the narrow window throughout the interval.
good mobility and would produce oil. From the log data, petrophysicists determined that the permeable layer was less than 10 ft [3 m] thick and was positioned about 6 ft [1.8 m] below the high-resistivity caprock layer. Log analysts were uncertain whether the zone with high mobility extended farther out in the reservoir or was simply a stratigraphic anomaly.

Even if the zone extended into the reservoir, engineers knew that effectively producing from such a small interval in the pilot well would be difficult. Thus, they designed a horizontal pilot producer to more effectively drain the reservoir. Challenges included using real-time data from LWD tools to verify the presence of the high-mobility zone and stay within this narrow, high-permeability window. Porosity and resistivity logs provided little help in identifying the zone with the best mobility.

The technical team determined that the best course of action was to drill the well with a trajectory that maintained a constant standoff or distance from the overlying caprock. The standoff was based on distance to boundary (DTB) measurements computed from a PeriScope tool. The team relied on true stratigraphic thickness (TST) data to maintain a constant position relative to the caprock location. Well placement engineers with Schlumberger were able to compute TST in real time using eXpandBG processing of formation dips picked from MicroScope images. Saudi Aramco personnel used these interpretations to instruct the directional driller in the proper direction to guide the PowerDrive rotary steerable system.

Based on results from the pilot hole, NMR data were judged to be insufficient to identify the zone with mobility. Consequently, an FPWD formation pressure while drilling tool was used to confirm that the wellbore trajectory remained in the high-mobility streak. To ensure that the wellbore followed subtle changes in dip and direction, the geosteering staff used interpretations from borehole images acquired with a MicroScope tool.

Geologists created a 2D structural model from pilot well data and forward modeled logging responses for the LWD tools. The well placement team landed the well near the interval, steering the well stratigraphically upward to attain the required distance to the upper boundary. Once the data from eXpandBG processing confirmed the required trajectory, the well was drilled maintaining the proper orientation (previous page).

FPWD data were acquired for the first 1,700 ft [520 m] and confirmed that the chosen path was following the high-permeability streak. Each FPWD mobility test required leaving the drilling assembly stationary for 20 min. Significant overpulls began to occur after each mobility test, and the FPWD tool was removed because of operational concerns related to hole conditions and sticking. The remainder of the well was then drilled using only DTB and TST data from eXpandBG and eXpandGST processing to determine corrections to the wellbore trajectory. Images from the MicroScope tool helped establish the formation dip and were a key input in the interpretation. The horizontal interval covered approximately 2,900 ft [884 m] and remained within a 4-ft [1.2-m] sweet spot window for the entire interval.

The well confirmed that the high-permeability streak was not a stratigraphic anomaly and extended far out into the reservoir. The well was tested after completion and produced at a rate of several thousand bbl/d. Further evaluation is ongoing, but early analysis confirms that because the well followed the high-permeability path, resources were accessed that otherwise might have been difficult to produce economically.

Knowledge Is Power
At one time, horizontal drilling was an exercise in geometry and drilling technology. However, as well placement techniques and practices have evolved, LWD tools have been introduced that provide well placement teams with a better grasp of geologic and subsurface structural conditions. Integrating downhole data into modeling software provides operators with the ability to visualize subsurface complexities. This knowledge gives operators powerful tools to modify drilling plans, alter wellbore trajectories and optimize completion programs.

Service companies continue to add to the assortment of LWD tools that may have been considered impractical for the drilling environment in the past. Pressure sampling, downhole seismic acquisition and acoustic logging devices were once considered to be beyond the capabilities of tools used while drilling. Just as these services have been accepted by the industry, high-resolution measurements that image the borehole and result in large amounts of data are now becoming available. Proper interpretation of these data has the potential to alter the way wells are drilled; such drilling is no longer based primarily on geometry but optimized for downhole structural conditions.

Structural steering involves more tools and requires more data for analysis than conventional drilling; in addition, the costs of structural steering are higher. But the answers provided by the tools and data to engineers and geologists have the potential to reveal better access to more of the reservoir, enhance recovery and produce more hydrocarbons. Structural steering may not be the answer for every well, but the opportunity to resolve the complexities of downhole geology offers operators a tremendous tool for enhancing resource recovery. —TS