Unconventional Resources

Successes in shale plays

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www.slb.com/shale
How do you define success?

In shale plays, success is determined by better reservoir understanding, and ultimately, greater ROI. Schlumberger has provided expert technology and services in every active shale play worldwide. Our local knowledge, global insight, and innovative technologies have consistently proven to help customers produce more with less—less risk, less rig time, less environmental impact, and less footprint. Learn how our industry-leading, integrated shale offerings can help you

- use seismic, core, and petrophysical measurement and analysis to better understand your reservoir
- reduce time to drill to total depth
- maximize reservoir contact during drilling and completions
- optimize production management.

Technology drives efficiencies

Careful selection of technology and services, and continuous improvement, is essential for long-term success, confident decisions, and improved operational efficiency. This collection of case studies demonstrates how the right combination of people, processes, and technology can meet the challenges of shale reservoir development. The booklet is organized by the domains of evaluation, drilling, completions, and production. Simply click on a title in the table of contents to view the story. An alternate table of contents, organized by play, is also included. To learn more about how we help our customers reduce risk and enhance production, go to www.slb.com/shale.
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sCore Lithofacies Classification Reveals Barnett Shale Reservoir Quality

Litho Scanner wellsite mineralogy and TOC outputs drive identification of optimal completion intervals

CHALLENGE
Reliably identify intervals with superior reservoir and completion quality in the Barnett shale.

SOLUTION
Input Litho Scanner* accurate, quantified mineralogy to the automated sCore* lithofacies classification scheme to generate a log display of the classification and quality-indicator overlays on the sCore ternary diagram.

RESULTS
Identified the optimal intervals for completion from the sCore reservoir and completion quality overlays.

Shale classification challenges
Key to successfully completing Barnett shale reservoirs is targeting intervals with superior reservoir and completion quality. However, these so-called shales are more than just fine-grained sedimentary rocks with a high content of organic matter. Rather, these organic mudstones are typically a complex mineralogic assemblage that is heterogeneous at fine vertical scales. In addition to identifying optimal intervals in terms of reservoir and completion quality, operators need a mineralogy-based classification to better understand depositional conditions and correlate reservoirs across different fields and basins.

The sCore classification for organic mudstones is defined by a ternary diagram, with the three apexes representing the dry-weight components clay, carbonate, and quartz, feldspar, and mica (QFM). The term “dominated” is used for a mudstone containing more than 80% of a particular component. When the primary component is 50% to 80% of the composition, the mudstone is described as siliceous (50% < dry-weight QFM < 80%), argillaceous (50% < dry-weight clay < 80%), or carbonate (50% < dry-weight carbonate < 80%). The term “rich” indicates a secondary component representing 20% to 50% of the total composition.
CASE STUDY: sCore shale lithofacies classification based on Litho Scanner mineralogy, Barnett shale

Optimal reservoir identification
Shale facies are readily and automatically identified using the sCore lithofacies classification scheme. The sCore classification is based on mineralogical relationships within a ternary diagram customized for organic mudstone lithologies to determine both lithofacies and reservoir and completion quality indicators.

The sCore log display is generated with minimal processing and no interpretation input required. Descriptive parameters such as organic carbon, pyrite, and the presence of expandable clays are flagged. The sCore log provides a consistent description of the organic mudstone section and the inputs necessary for effective decision making when selecting a landing points for well placement, tailoring completion designs, and planning a drilling development project. Quality indicator parameters such as porosity, total organic carbon (TOC), fracture density, and stress are also overlaid on the sCore ternary diagram to relate the parameter quality to the sCore lithofacies types.

Accurate mineralogy input for the sCore classification comes from Litho Scanner high-definition logging for carbonate, clay, QFM, and TOC in combination with additional inputs from basic triple-combo logs for porosity and resistivity. The Litho Scanner mineralogy is provided at nearly immediate turnaround, instead of having to wait for laboratory X-ray diffraction (XRD) analysis of core samples.

Lithofacies quality indicators
From the sCore log for the Barnett shale well, reservoir quality and completion quality indicator overlays on the sCore ternary diagram were generated. The color-coded points represent the different log depths for the indicator parameters that correlate with reservoir quality (top diagram) and completion quality (bottom diagram).

Gas-filled porosity (top) and in situ stress (bottom) measurements plotted on the sCore ternary diagram provide better understanding of reservoir quality and completion quality distribution within the Barnett shale.
PDC Mountaineer Improves Production More Than 50% With Optimized Completion Designs

Sonic Scanner tool data and Mangrove methodology help increase reservoir-to-wellbore connectivity in Marcellus shale while reducing time, costs, and risk.

**CHALLENGE**
Improve productivity and operational efficiency in horizontal wells by optimizing the placement of perforation and hydraulic fracturing treatments.

**SOLUTION**
Use Sonic Scanner* acoustic scanning platform and the Mangrove* completion advisor workflow to engineer precise staging and perforating designs.

**RESULTS**
Significantly enhanced stimulation coverage across the length of the laterals, increasing production by more than 50% and eliminating screenouts. PDC Mountaineer (PDCM) now plans to use Sonic Scanner logs in conjunction with the Mangrove platform on all future Marcellus development.

“Schlumberger has provided us with a unique and affordable approach to optimize our recoverable reserves in the Marcellus shale. PDCM will not complete any of our lateral Marcellus wells without first running this service and evaluating the results.”

Dewey Gerdom
CEO, PDC Mountaineer, LLC

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**PDCM wanted to optimize horizontal well completions and productivity**
To complete its Marcellus shale’s horizontal wells simply and cost-effectively, PDC Mountaineer, like most operators, typically uses geometric perforation designs. With this technique, perforation clusters are placed at equidistant points along the lateral. However, microseismic monitoring showed that this type of stage selection often distributed hydraulic fracturing treatments unevenly. The fracture treatments propagated to the lowest-stress zones, leaving the majority of perforations understimulated. PDCM wanted to gain a deeper understanding of the reservoir and improve reserve recovery. PDCM partnered with Schlumberger to identify low-stress intervals, develop more effective completion designs, and ultimately improve well economics.

**Sonic Scanner tool and Mangrove methodology optimized completion designs**
Schlumberger deployed its Sonic Scanner acoustic scanning tool on wireline to map out mechanical rock properties. The tool’s advanced borehole acoustic measurements were loaded into the Petrel* software platform and interpreted using the Mangrove completion advisor workflow. Once processed, the critical well information, including in situ stress, lithology, and Young’s modulus, enabled PDCM and Schlumberger to engineer custom staging and perforating designs. This ensured more consistent stimulation along the entire lateral, and lower breakdown and treating pressures.

“When we’ve used the Schlumberger Sonic Scanner tool to identify and place the staged intervals based on like-rock completion, we have never screened out,” said Jacob Caplan, Senior Completions Engineer, PDC Mountaineer. “We’ve also had a better handle on the breakdown pressures to be expected, further reducing our risk of screening out. The screenout rate was 35% when we didn’t use Sonic Scanner tool, and on average, each screenout costs PDCM USD 300,000.”

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Microseismic monitoring clearly shows that the fracture initiates in the lowest-stress interval (in red), and treatments tend to understimulate higher-stress intervals (in pink and blue).

Stimulation
CASE STUDY: Sonic Scanner tool data and Mangrove methodology help increase reservoir-to-wellbore connectivity

Production increased more than 50%, leading PDCM to use the Mangrove workflow in all future wells

The Flow Scanner* horizontal and deviated well production logging system showed significantly higher flow rates from wells that used the Sonic Scanner tool and Mangrove methodology than offset wells completed with conventional geometric perforating designs.

“Based on the total number of wells PDCM has producing in the Marcellus, I believe the minimum increase we could expect from utilizing this methodology is 50–60%,” said Caplan.

After the success of the pilot wells, PDCM decided to use this technique to help maximize ROI of all future horizontal wells in the Marcellus shale. The Mangrove workflow has been used in subsequent PDCM wells with similar results. Recently, PDCM used Mangrove software to automatically select intervals, dramatically reducing interpretation time.

Petrel software allows the logs obtained in the lateral to be viewed in a 3D environment. This enables engineers to make better decisions when designing the completion.

Production improvement was directly attributed to the identification and selection of optimal perforation locations based on property logs.

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ECS Petrophysical Analysis Finds Additional 250 ft of Productive Shale

Unconventional reservoirs discovered above and below limestone reservoir to also be completed, Midland basin

**CHALLENGE**
Find bypassed reserves in shale and carbonate formations adjacent to a conventional limestone reservoir.

**SOLUTION**
Run Platform Express* integrated wireline logging tool in combination with the ECS* elemental capture spectroscopy sonde to accurately determine clay content, mineralogy, and matrix properties to support robust, detailed petrophysical analysis.

**RESULTS**
Identified 150 ft of productive unconventional shale reservoir above the currently produced limestone and another 100 ft below it.

**Looking beyond the conventional reservoir**
An operator’s target zone in the Midland basin is a conventional limestone bounded by shales. The reservoir varies from 100 to 150 ft in thickness and is produced from single-stage jobs designed to contain the stimulation. Because other wells in the area had mud logging shows, the operator wanted to know if additional producible formations were present.

**Conducting fast, detailed petrophysical evaluation**
The ECS elementary capture spectroscopy sonde was combined with the Platform Express integrated wireline logging tool for one-run measurement to support petrophysical analysis. The Platform Express tool provides high-resolution resistivity, density, and microresistivity measurements. The ECS sonde measures relative elementary yields for the determination of lithology, porosity, permeability, and fluid saturations and their producibility.

**Finding bypassed pay in unconventional reservoirs**
Petrophysical analysis found that the shales bounding the limestone reservoir are producible unconventional reservoirs, extending 150 ft above the limestone and 100 ft below it. The operator plans to reevaluate these bypassed reserves in completed wells and target them in new wells. The lithology from the ECS measurements will be used to determine rock mechanical properties for stimulation design, including the identification of barriers to fracture propagation.
Petrophysical analysis integrating Platform Express and ECS measurements found that the shales above and below the limestone reservoir total 250 ft of productive rock.
Integrating Coiled Tubing and Production Logging for ConocoPhillips

ACTive PS service uses fiber-optic telemetry for a single-run strategy in the Barnett Shale

CHALLENGE
Understand fracture/completion program effectiveness using production logging technologies. Compare production monitoring capabilities of fiber optics in dry gas wells.

SOLUTION
Use ACTive PS* integrated coiled tubing (CT) production service to acquire production logging and distributed temperature survey (DTS) measurements in a single run.

RESULTS
Validated production monitoring capabilities of fiber optics, with a very strong correlation to wireline production logs. Saved one trip downhole for each well, reducing risk, cost, and time.

Operator seeks long-term monitoring without regular intervention
Operating in the Barnett Shale, ConocoPhillips required long-term production monitoring to analyze completion effectiveness, reservoir depletion, and zonal flow contributions. The conventional approach for horizontal wells required separate production logs over different time periods to evaluate changing well performance.

Integrated service uses fiber-optic telemetry
ConocoPhillips chose to explore and evaluate the use of fiber optics. An integrated technique was applied to two wells. Rather than validate DTS measurements with separate CT runs (fiber-optic–enabled CT for DTS and an electric line inside CT for production logging), the company acquired both DTS and FloScan Imager* measurements in one run using the ACTive PS service.

Conventional logging techniques performed with ACTive PS service save time and money
ConocoPhillips required DTS and FloScan Imager logs, and ACTive PS enabled real-time telemetry to surface, eliminating the use of wireline logging cable–equipped CT and capturing both logs in a single run. This technique reduced time, risk, and cost and ultimately provided two logs without the additional effects of tripping CT in and out of the well to switch CT strings.

www.slb.com/ACTivePS
Barnett Shale Operations Achieve Remote Real-Time Microseismic Interpretation with Private and Dedicated Wireless Networks

Case study: Expediting field operations and improving collaboration for accurate decision making

Challenge
Optimize remote processing and collaborative interpretation of microseismic data acquired and transmitted from wellsite to office. Access very large seismic datasets in real time and provide mapped microseismic locations for display at both the wellsite and remote sites.

Solution
Use the InterACT* connectivity, collaboration, and information system; StimMAP LIVE* real-time microseismic fracture monitoring, in conjunction with Petrel* seismic-to-simulation software; and IPerformer* Wireless Broadband service, a WiMAX-based terrestrial radio network with 1,700-bps circuitry for high-volume, high-speed, low-latency data transmission.

Results
Improved decision making by instantaneously communicating field operations data to the corporate office. Delivered cost-effective, consistent, and high-quality connectivity (100% uptime and less than a 60-ms delay).

Inefficient microseismic data transmission
In the Barnett Shale, the largest natural gas play in Texas, hydraulic fracture monitoring (HFM) services are often used to map ongoing treatments. Operators needed more efficient office support of critical decisions, so a new method was sought to improve transmission speed of high volumes of microseismic data for real-time processing and interpretation.

Processing data remotely would improve overall efficiency, minimize safety risks, and provide access to high-power computer systems not available in the field. Remote transmission of full seismic data waveforms (not just triggered events) was key to reaching this goal. The main difficulty was that seismic datasets could exceed 5 GB, causing throughput and delay issues that traditional data transmission methods could not always handle. The new method had to provide microseismic event data to decision makers on location or in the office within 30 seconds of detection.
Case study: Expediting field operations and improving collaboration for accurate decision making

Combination of services for a pilot well
Schlumberger Data & Consulting Services (DCS) and Schlumberger Information Solutions (SIS) collaborated on HFM requirements. A combination of StimMAP LIVE, Petrel, IPerformer, and InterACT technologies was first applied to a pilot well to test mobilization, setup, and performance.

StimMAP LIVE diagnostic services were run by DCS to monitor microseismic fractures in real time as they were created. Used with SIS Petrel software, this service enabled operators to visualize fracture development and make real-time treatment adjustments to optimize job effectiveness.

Partnered with ERF Wireless, Inc., SIS also delivered a high-capacity broadband service to the Barnett operators. This included IPerformer connectivity—a 1,700-bps, WiMAX-based terrestrial radio circuit positioned alongside the standard VSAT service. Designed for oil and gas business applications, the IPerformer service ensured high performance, reliability, and security for transmitting full waveform data.

The solution also offered low latency, with less than a 60-ms delay, no contention (1,700 bps unshared), and 100% reliability. Both onsite and remote geophysicists could access ongoing jobs in real time through a continuous feed from the field via the Internet and the Schlumberger InterACT Web server, employing secure encryption. Network statistics recorded over a 24-hour period during pilot well testing indicated:

- uptime of 100%
- upload bandwidth speeds of 1,700+ bps
- download bandwidth speeds of 1,700+ bps
- average upload speed of 468 KBps
- average latency of 20 ms or less.

Collaborative seismic interpretation
The pilot showed that collaborative seismic interpretation could be accomplished remotely with minimal processing and visualization delay, bringing field operations to operation support center experts in real time. The wireless broadband service enabled the WiMAX network to achieve 100% uptime with negligible packet retransmissions. Wellsite and remote staff indicated that where high data rates are expected, this communication service performs significantly better than using VSAT communications alone. Due to the pilot’s success, this solution will be expanded to other operations within the communications coverage area of Texas and surrounding states.

Schlumberger Information Solutions
Schlumberger Information Solutions (SIS) is an operating unit of Schlumberger that provides software, information management, IT, and related services. SIS collaborates closely with oil and gas companies to solve today’s tough reservoir challenges with an open business approach and comprehensive solution deployment. Through our technologies and services, oil and gas companies empower their people to improve business performance by reducing exploration and development risk and optimizing operational efficiencies.

E-mail sisinfo@slb.com or contact your local Schlumberger representative to learn more.

www.slb.com/sis
Real-Time Measurements Optimize Marcellus Shale Well Placement

Marcellus shale operator repeatedly places long lateral in richest target zone

**CHALLENGE**
Land operator’s first Marcellus Shale production well in the best reservoir portion of the Marcellus Shale and place a 4,000-ft lateral section in a narrow target interval.

**SOLUTION**
Combine real-time geosteering using EcoScope* measurements with azimuthal images and interpretation support from Schlumberger well placement engineers.

**RESULTS**
Landed well 12 to 14 ft below the top of the target interval; lateral sections steered using EcoScope measurements remained within the target.

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**Maximize contact with the reservoir target**
An independent operator worked with Schlumberger to interpret wireline logs from vertical wells to understand the heterogeneity of distinct layers within the Marcellus Shale. The operator wanted to place its first Marcellus Shale well in a 57-ft [17-m] thick target interval it had mapped using offset well logs and seismic data, noting that the Marcellus dips as much as 2.5° near the potential well location.

The company decided to log while drilling to correlate real-time measurements with seismic data to steer a long lateral section within the target interval. A Schlumberger well placement engineer was engaged to interpret the real-time logging data and advise the operations team from the operating company.

**Steer within dipping beds**
The well was landed in the middle of the defined target, 12 ft shallower than planned. To drill the horizontal section, measurements and density images from the EcoScope multifunction logging-while-drilling service were used to steer the well parallel to the target beds.
The density images were also used to map individual shale beds. A Schlumberger well placement team worked with the operating company to match the real-time measurements and derived dips from density images with dynamic synthetic models to provide visualization for steering. This cooperation helped improve well placement because the dip of the Marcellus was found to vary locally, averaging less than 1°. The lateral was placed within a 30-ft [10-m] stratigraphic window that is only 18 ft thick when converted to true vertical thickness.

sonicVISION* data acquired while drilling was of good quality and showed no obvious indications of open fractures. This data was used to derive rock mechanical properties along the lateral, which revealed significant variations in the minimum horizontal stress. Using Schlumberger LWD Shale Gas Completion Optimization Solutions, perforations were designed in zones of lowest stress, low clay content, and high free gas content along ten hydraulic fracturing stages. This analysis helped the operating company design the stage intervals and pinpoint perforation clusters to target intervals with the optimal properties for hydraulic fracturing.

**Optimize future wells**

The well penetrated the desired target interval and proved to be a good producer. The excursions of the lateral outside the target confirmed that even subtle dips in the Marcellus Shale should be anticipated when planning wells. By penetrating a substantial section within the target, the operating company optimized the completion for maximum recovery from the reservoir.

The superior production from the new well and wells drilled later using the EcoScope service showed the value of advanced measurement technology for placing wells in the most productive zone. The operating company committed to a multiwell drilling campaign incorporating the EcoScope service and Schlumberger well placement engineering support.

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Mississippian Shale Seismic Reservoir Characterization Improves Gas Production

Seismic processing, inversion, and Ant Tracking high-grade drilling locations and enable more-effective completion operations.

**CHALLENGE**
Understand anisotropy of shale reservoir and delineate shale reservoir sweet spots, reservoir areas to be avoided, and subtle faults that previously had been overlooked. Optimize drilling and completion in a 9-mi² pilot area.

**SOLUTION**
Perform full seismic reservoir characterization, including azimuthal velocity analysis, prestack inversion, and fault image enhancement in a 9-mi² 3D seismic grid, and integration of measurements from three wells.

**RESULTS**
Achieved more consistently effective completions, optimal drilling locations, and more profitable development of shale reservoirs. Reduced operational risk of diverting into a fault with accurate fault identification.

**The challenges of anisotropic rocks**
Operators in shale plays face significant exploration and delineation challenges that can be addressed using seismic methods. A fundamental challenge is that the seismic velocity of shale tends to be much greater horizontally than vertically. Also, velocities vary azimuthally under the influence of stress and pre-existing fractures. Understanding both these anisotropies is important in predicting the location of pre-existing natural fractures in the rock and how induced fractures might grow. Delineating sweet spots, mapping rock stiffness vertically and laterally, and identifying drilling hazards such as faults also improve drilling and completion operations.

The relative importance of specific reservoir characteristics varies from shale to shale. For example, the relative importance of pre-existing fractures and lateral variations in stress varies widely from shale to shale. Both are important in this particular shale. Also important is lithology. In each shale, the most porous rocks are those with the highest total organic carbon (TOC). This could be the carbonate facies, the siliceous facies, or the argillaceous facies, depending on the shale. In this pilot study area, the siliceous facies contained most of the porosity. Fortunately, this is also the facies with the greatest stiffness, so this was the interval to be drilled and fractured.

The operator wanted to evaluate shale acreage using a 9-km² 3D seismic grid and logs and production data from two wells. Subsequent drilling during the project provided an additional control point, the analysis of stress from a Sonic Scanner® acoustic scanning platform log in the new well. Results of this reservoir characterization study would be used to plan and drill additional wells.

**Innovative seismic analysis**
Simultaneous inversion of prestack surface seismic data yields seismic rock properties that can delineate reservoir sweet spots, such as the more siliceous portions of this Mississippian shale.

Ant Tracking was performed to enhance and identify planar features indicative of faults. Also, more subtle but operationally important features like fracture swarms degrade the seismic image and can be detected by Ant Tracking. This method of enhanced fault delineation reduces the risk of drilling near faults by providing a high-resolution image of fractures and faults, better than interpretation using only conventional seismic data or fault attributes like coherence or variance. These reservoir features can divert the energy of a hydraulic fracturing stage and impair production from that stage.
The integration of seismic rock properties and detailed fault delineation provides effective delineation of sweet spots and drilling hazards, improving shale gas profitability. Seismic interpretations were integrated with log data, including Ant Tracking results and Sonic Scanner data. Together, these provided detailed delineation of fault features, reservoir sweet spots, and stiffness stratigraphy that went well beyond what would be discerned using only conventional analysis of the seismic data.

**Improving drilling results**

In this Mississippian shale reservoir, zones with the greatest azimuthal anisotropy proved to be more productive, although this result does not necessarily hold true for other shale reservoirs. Using maps and cubes generated through seismic reservoir characterization, the operator was able to improve efficiency by focusing drilling efforts in areas where production would be greater.

As a result of seismic reservoir characterization, the operator realized that potential infill drilling locations were not likely to achieve adequate production in this pilot area. By focusing on high-graded drilling locations, drilling operations were more effective and financial results more positive.
Consulting Services Identifies Key Technologies to Drill and Evaluate Wells in the Niobrara Formation

Expert analysis of high-tier logs and real-time data targets the most productive zone in unconventional oil reservoir

**CHALLENGE**
Determine key production drivers in Niobrara formation, target interval of highest reservoir quality, and accurately geosteer the horizontal lateral within that zone.

**SOLUTION**
Engaged Schlumberger DCS to recommend and run a suite of fit-for-purpose tools to characterize the reservoir, guide real-time geosteering, and optimize completions.

**RESULTS**
Identified the 10-ft interval of greatest potential, stayed in zone for entire length of the 3,000-ft lateral, and modified completion design to maximize well performance.

“Schlumberger DCS was very easy to work with and provided the expert guidance needed to successfully complete our first three horizontal wells within the desired stratigraphic interval.”

Independent Operator, Denver-Julesberg basin

**Making sure to get it right—from the start**
In the fall of 2010, a small operator in the Denver-Julesberg basin of Colorado began its first horizontal drilling campaign in the Niobrara formation, an unconventional oil reservoir with four laterally continuous chalk units. Based on historical drilling data, the operator knew the “B” unit was the primary target in this area, but did not know what portion of the 36-ft zone would be most productive.

The operator needed to understand the reservoir’s major production drivers—petrophysics, mechanical properties, natural fractures, structural complexity, and so on—and use that knowledge to optimize drilling and completions not only for the first well, but for the whole campaign.

Since the company’s internal resources were limited and they were relatively unfamiliar with the area, decision makers wanted to shorten the typical learning curve associated with entering any new unconventional play. They wanted to make sure they got it right, from the very beginning. To do so, they turned to the seasoned geotechnical consultants of Schlumberger Data & Consulting Services (DCS).

**Accurately quantifying the key production drivers**
The client approached DCS because of its reputation consulting on unconventional projects in the Denver-Julesberg basin. Based on the operator’s needs, DCS recommended a suite of high-tier, fit-for-purpose logging measurements for the pilot hole and a geosteering solution for the lateral.

Schlumberger Platform Express® integrated wireline logging, ECS® elemental capture spectroscopy, and CMR® combiable magnetic resonance tools accurately quantified reservoir quality—mineralogy, porosity, permeability, and saturation. Borehole images from FMI® fullbore formation.
microimager helped unravel natural and induced fractures. And acoustic behavior information from Sonic Scanner\* acoustic scanning platform characterized the Niobrara’s stress state and other mechanical properties.

Expert processing, analysis, interpretation, and integration of field log data by DCS geoscientists and engineers yielded a better understanding of the target reservoir in the area. In the process, they identified a 10-ft interval in the middle of the Niobrara “B” unit as the zone of greatest potential. After determining where to drill the horizontal lateral, the team’s next challenge was to keep the wellbore within that more-productive zone as much as possible.

**Targeting the productive zone, optimizing completions**

Because of the formation’s extensive lateral continuity, Schlumberger recommended its new MicroScope\* advanced resistivity and imaging-while-drilling service to guide geosteering operations. A DCS well placement engineer interpreted resistivity images in real time to construct an initial cross-section of the target interval and to determine when the borehole was climbing or dropping. As a result, the well successfully remained in the 10-ft zone of highest reservoir quality for more than 3,000 ft.

After drilling was completed, further processing and interpretation of high-resolution MicroScope imagery revealed detailed bedding and fracture intensity, as well as the strike and dip of open and healed natural fractures. This refined the structural section along the well path, enabling engineers to optimize the original completion design in three ways: (1) by combining similar lithologies, (2) by avoiding the placement of packers in areas of intense fracturing, and (3) by managing fluids and pump rates to prevent excessive leakoff and achieve near-wellbore connectivity.

Finally, results from this initial well empowered the operator to make more informed decisions about additional wells in its ongoing Niobrara drilling program.

**Production Driver Importance Technology and Services**

<table>
<thead>
<tr>
<th>Production Driver</th>
<th>Importance</th>
<th>Technology and Services</th>
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<tbody>
<tr>
<td>Reservoir quality (porosity, permeability, saturation)</td>
<td>Hydrocarbon storage, oil in place, and matrix contribution to flow</td>
<td>Platform Express*, CMR*, ECS*, Rt Scanner*, and core calibration</td>
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<tr>
<td>Natural fractures and structural complexity (faults, curvature)</td>
<td>System permeability, reservoir connectivity, ability to stay in zone</td>
<td>FMI*, MicroScope*, anisotropy, 3D seismic</td>
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<tr>
<td>Charge access</td>
<td>Fluid properties, pore pressure</td>
<td>ECS, resistivity, core calibration, fluid property mapping</td>
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<tr>
<td>Fluid properties and pressure</td>
<td>Downhole pressure, oil properties</td>
<td>In situ pressure and sampling from MDT* and PressureXpress* services</td>
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<tr>
<td>Geomechanics</td>
<td>Stress orientation and magnitude for fracture containment, achieving transverse hydraulic fractures, achieving wellbore stability</td>
<td>Sonic Scanner*, mechanical earth modeling, StimMAP* microseismic monitoring</td>
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<tr>
<td>Well placement</td>
<td>Intercepting best-quality part of reservoir for production, optimal stimulation, avoiding near-wellbore pinchoff</td>
<td>Real-time geosteering with image logs</td>
</tr>
<tr>
<td>Well performance</td>
<td>Validation of hydraulic fracturing success and need for well placement</td>
<td>FloScan Imager*, production logging</td>
</tr>
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</table>

Based on this project, Schlumberger identified a range of technologies and services capable of characterizing and quantifying the key drivers of Niobrara oil production.

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Advanced Logging Technology Reveals the Most Productive Zones in Woodford Shale Wells

Integration of LWD and production logging measurements identifies the most productive zones of the shale reservoir in Oklahoma

**CHALLENGE**
Optimize placement and production from future wells in the Woodford Shale by identifying and perforating the most prolific reservoir rock.

**SOLUTION**
Integrate LWD along the lateral with neutron, density, and resistivity data from a vertical offset well to identify the most productive reservoir intervals. Refine mapping of reservoir zones using LWD and identify sweet spots using Flow Scanner® horizontal and deviated well production logging system.

**RESULTS**
Integration of EcoScope®, Platform Express®, and Flow Scanner data determined that 90% of gas came from perforations placed in zones identified as most productive.

*Geochemical analysis used to identify drilling and production sweet spots in the Woodford Shale. Two consecutive stages show 19% vs. 10% gas contribution. Proper measurements and completion procedures are necessary for understanding reservoir performance and optimizing future wells.*

**Mapping reservoir intervals**
An operator performed an LWD operation on a 4,000-ft [1,220-m] lateral in the Woodford Shale. The measurements were run to understand how the formation dip changes laterally and how the reservoir properties vary across the vertical layers. Working with engineers from Schlumberger Data & Consulting Services, the operator integrated offset vertical “triple combo” neutron, density, and resistivity measurements with measurements obtained with the EcoScope multifunction LWD service to map nine distinct layers in the Woodford Shale with a thickness of 220 ft [67 m].

**Integrating measurements to identify high-quality reservoir intervals**
After the well was put on production, the Flow Scanner multispanner production logging tool was run, and data from it was integrated with maps of reservoir zones to identify the most prolific zones within the Woodford Shale. The Flow Scanner measurements determined that more than 90% of the gas was produced from perforations located in three of the nine mapped zones.
CASE STUDY: Integration of LWD and production logging measurements identifies the most productive zones of the shale reservoir in Oklahoma

These three highly productive layers were adjacent to one another and within 82 ft [25 m] of each other. Furthermore, interpretations derived from EcoScope and Flow Scanner data showed that perforation clusters placed across higher free gas, lower clay content, and lower calcite volume produced more gas.

**Optimizing future wells**

Lateral measurements are crucial to place wells in the most productive layers within the Woodford Shale. Placing perforation clusters across zones with the most favorable rock properties should result in stronger performance from all the perforation clusters, ultimately increasing the total well production. The operator will apply lessons learned from this well to optimize future operations. This approach of integrating measurements from vertical logging data, lateral LWD data, and production logs is essential to understand how to optimize production from other heterogeneous shale plays.
Advanced Analysis of Magnetic Resonance Finds Laminated Pay, Eagle Ford Shale

Matrix nonuniformity detailed by combining 50-burst magnetic resonance application and high-resolution density logging

**CHALLENGE**
Discriminate intervals with the best production potential in what appears to be uniform matrix on standard log suites.

**SOLUTION**
Run the newly developed 50-burst magnetic resonance acquisition application in combination with the Three-Detector Lithology Density (TLD) tool to discern both extremely low-porosity and medium-porosity laminations through statistical analysis.

**RESULTS**
Used the improved ability to locate oil-bearing laminated intervals to optimize placement of four additional laterals.

**Conventionally undifferentiated shales**
Standard log suites, which were developed for conventional reservoirs, characterize the Eagle Ford shale play as a uniform matrix. Analysis of logs with this conventional resolution cannot easily find where the best potential for oil production may occur.

**Fifty-burst magnetic resonance application and high-resolution density**
Magnetic resonance logging has long been applied to discern moveable from nonmoveable fluids regardless of the matrix, which is of great utility in clay-bearing formations. The new 50-burst application improves the statistics for the smallest pores by enabling the collection of more data by an advanced prepolarizing magnetic resonance tool. The result is a 6-in or greater resolution of the clay-bound micropore region of the rock.

The TLD tool uses three detectors to obtain a high-resolution 8-in density output. The TLD detector with 2-in resolution is normally applied to correct for minor wellbore changes resulting from the hole condition and mudcake. In the Eagle Ford the matrix is primarily carbonate and the wellbores are typically smooth. This logging environment allows use of the 2-in detector as a standalone porosity device to improve the visibility and reliability of the TLD curves.

**Visible laminated pay**
The Eagle Ford is highly laminated with thin laminations. Run with a conventional logging suite, the 8-in-resolution density cannot differentiate laminations with substantial porosity. However, logging analysis combining the 50-burst magnetic resonance application and high-resolution TLD readily identifies laminated pay by differentiating very small pores, micropores, and potentially oil-bearing matrix. Standard-resolution analysis presents only an average of the matrix, which cannot discriminate laminations.

Logging with the three TLD density curves at different resolutions identifies intervals for further analysis with the 50-burst magnetic resonance application to find completion opportunities not seen by standard logging.
**CASE STUDY:** Laminated pay identified by advanced magnetic resonance analysis, Eagle Ford Shale

Track 3 overlays the standard-resolution density with the 8-in and 2-in curves. The resolution of the 2-in curve is consistent with the enhanced image curve in Track 4. The 2-in-resolution density shows higher porosity (circled) along certain layers that is as much as 5-pu higher than standard resolution. In the same intervals, the 50-burst application in Track 5 differentiates very small pores, micropores, and potentially oil-bearing matrix. Compared with the detail provided by the TLD and 50-burst logs, the standard-resolution analysis in Track 6 does not show any bedding but merely an average of the matrix.

www.slb.com/wireline

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Borehole Images Help Optimize Well Placement and Completion

Resistivity- and imaging-while-drilling service enables Wyoming operator to identify and characterize fractures along 3,000-ft lateral

**CHALLENGE**
- Place long horizontal wellbore within 10-ft highly fractured layer of chalk bench.
- Evaluate fractures along lateral section.

**SOLUTION**
Use MicroScope® high-resolution resistivity-while-drilling and imaging-while-drilling service for real-time structural interpretation and fracture identification.

**RESULTS**
- Kept 3,000-ft lateral within 10-ft target of best quality pay.
- Acquired high-resolution images to facilitate fracture identification and fault estimation and provide structural analysis.
- Optimized stage designs for hydraulic fracturing.

The operator used MicroScope high-resolution images to optimize well placement and hydraulic fracturing operations for maximum recovery.

**Keep wellbore within target zone**
An operator in Wyoming, USA, planned to develop the Niobrara formation in the Denver-Julesburg basin by combining horizontal drilling with multistage hydraulic fracturing. This formation consists of up to four laterally continuous chalk benches with intervening marls. Both permeability and porosity in the Niobrara chalk are relatively low, and production was expected to be enhanced by natural fractures. From historical drilling data in the area, it was known that the 33-ft “C” bench layer was the most attractive interval. This was reconfirmed and refined by openhole logs run in a pilot hole, where the operator identified a 10-ft window as the final lateral zone target. Keeping the wellbore within the highly fractured layer identified in the pilot hole would require accurate real-time information to guide steering decisions.

**Make proactive well placement decisions**
The operator achieved the well placement needed to optimize recovery by using MicroScope service to provide real-time acquisition and transmission of high-resolution electrical borehole images, azimuthal gamma ray measurements, and multidepth measurement of formation resistivity. Analysis of this information in real time allowed proactive well placement decisions to be made by comparing the apparent dip of the formation to the borehole trajectory.

High-resolution MicroScope real-time images, along with azimuthal gamma ray, were used effectively to keep the 3,000-ft lateral within the target window to maximize reservoir contact.
CASE STUDY: High-resolution images enable Wyoming operator to identify and characterize fractures

Recorded MicroScope images showed approximately 349 open natural fractures (top) and 867 healed natural fractures (bottom) that strike northwest to southeast and dip steeply to the northeast and southwest. The open fractures were responsible for significant mud losses during drilling.

Maximize reservoir contact and optimize fracturing stages
Use of MicroScope service enabled the operator to maximize reservoir contact in the desired chalk bench. In addition, analysis of the high-resolution MicroScope images facilitated fracture identification, fault estimation, and structural analysis to optimize stage designs for hydraulic fracturing. The packers were staged to complete similar zones together and placed away from large open fractures. Sleeve ports were positioned close to open natural fracture swarms.

Contact your local Schlumberger representative to learn more.

www.slb.com/MicroScope
New ONYX II Cutter Technology Saves East Texas Basin Operator USD 250,600
Faster drilling reduces cost per foot by 44%, sets Freestone County ROP record

**Challenge**
Develop new cutters to further expand the PDC application envelope into harder, more abrasive formations.

**Solution**
Launch multipronged research initiative to exploit new, hard materials science and manufacturing techniques that will enable the production of ONYX II* PDC cutters.

**Result**
Reduced drilling costs by 26% in 9¾-in hole section while setting a new Freestone County, Texas ROP record. Increased footage capabilities to construct a 6½-in Bossier lateral reducing cost per foot by 20%. Drilled a 7¾-in vertical wellbore at 115.7 ft/h, increasing ROP by 95% and reducing cost per foot by 44%.

New cutters to drill harder and more abrasive formations required
Devon Energy must drill the hard and abrasive Travis Peak, Cotton Valley, and Bossier formations to tap Jurassic natural gas reserves in the prolific East Texas basin. The unconfined compressive strength (UCS) of the Travis Peak and Cotton Valley formations ranges from 9,000 psi to 32,000 psi. In the area, the interbedded Travis Peak is approximately 1,800 ft thick; the Cotton Valley is 1,400 ft thick. The alternating lithologies and large UCS variation are not conducive to smooth, vibration-free PDC drilling. In the last nine years, a vast number of wells have been drilled through these difficult, thick formations using PDC bits equipped with leached cutter products (LC). And while the LC manufacturing process enhances thermal stability, which improves abrasion resistance, most PDC bits used in this area were still tripped near the top of the Travis Peak. Bit replacement was necessary, because the LC’s active shearing edge was quickly dulled reducing ROP below an acceptable level. This limitation prevented further advancement of PDC drilling in the region, and drove the industry to launch an extensive engineering research and manufacturing initiative to develop a cutter that could endure harder and more abrasive formations.

More footage and higher ROP break through
In 2008, Smith Bits mastered a two-step HP/HT manufacturing method that produced ONYX* PDC cutters, which enabled PDC bits to drill more footage at higher ROP. Intervals that normally required multiple PDCs to reach TD could, in some cases, be drilled using one bit with ONYX cutters. Despite this innovation, the majority of bits being pulled were still in less than desirable dull condition, which added significantly to the cost of drilling. Further improvements were necessary to advance the cutter’s resistance to abrasive wear.

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The 7¾-in MSi616 drill bit with ONYX II PDC cutters recorded an ROP of 115.7 ft/h.

The 6¼-in MSi713 drill bit with ONYX II PDC cutters reduced cost per foot by 20%.
CASE STUDY: New bit design produces a significant improvement in drilling performance

Technical team advances diamond cutting materials
To take cutter performance to the next level, engineers focused on improving diamond sintering and post-processing technologies. The development effort, which included personnel from R&D, engineering, and manufacturing, concentrated on three initiatives intended to improve the cutter’s resistance to abrasive wear:
- Increase density/packing of diamond structure
- Synthesize diamond table under extreme HP/HT conditions
- Develop a post-pressing process to enhance thermal stability

The initiatives led to gains in hard materials science and enhanced manufacturing processes that resulted in next generation ONYX II cutter technology. In laboratory wear-index tests, ONYX II cutter has demonstrated a 15% improvement in resistance to abrasive wear compared to the original ONYX cutter shearng elements. The new cutter’s ability to retain a sharp edge would mean increased drilling efficiency in the targeted application. ONYX II cutter field tests demonstrated a 15% average increase in ROP while improving overall dull bit condition.

IDEAS optimizes application-specific PDC design
To fully exploit the ONYX II cutter advantage requires a dynamically stable bit body with the proper blade count and optimized cutter placement. This was accomplished using the IDEAS* integrated drill bit design platform rock sample laboratory and modeling system to create a real-world virtual environment. With the IDEAS platform, designers can observe how a bit interacts with actual formations as an integral part of the total drilling system. Engineers can then test and analyze the results of iterative design changes to rapidly advance an engineering concept to a field-proven PDC design.

Devon Energy is actively developing Bossier and Cotton Valley natural gas reserves in Freestone and Harrison counties with horizontal drilling techniques.

Although depths of the Travis Peak and Cotton Valley formations vary from county to county, thickness and UCS of these two zones is consistent. PDC bits with ONYX cutters were recently run in two of the area’s wells and recorded measurable performance gains compared to offsets drilled with standard cutters:

Well #1: Bit with ONYX cutters saves USD 120,000
To test drill a 9¾-in vertical hole section, a six-bladed MSI616PX equipped with 16-mm ONYX II cutters was selected. The bit drilled 1,232 ft at an average rate of 65.5 ft/h reaching the Travis Peak in one run.

The bit set a new Freestone County ROP record for PDC drilling from under surface casing to the Travis Peak. A cost analysis was performed using footage totals and drilling hours from four direct offset wells in which similar 9¾-in hole sections were drilled with bits using standard PDC cutters. Three of the four wells required two PDC bits to reach the required depth, with one offset requiring three PDCs to complete the interval. Using ONYX II cutters reduced interval cost per foot by 26% compared to the four-well offset average; this equated to a one-run savings of USD 120,000.

Well #1 (Lateral): Bit with ONYX cutters drops cost per foot 20%  
To construct the 6½-in Bossier lateral, engineers selected a seven-bladed MSI713WUPX equipped with 13-mm ONYX II cutters. The run was successful and the bit drilled significantly more footage compared to a competitor’s PDC run on a comparable BHA. An analysis, using standardized bit price and rig rate, revealed a 20% reduction in cost per foot compared to the four-well offset average and a total savings of USD 30,000. The ONYX II cutters also improved the bit’s dull condition.

Well #2 (Harrison County): Bit with ONYX cutters increases ROP 95%  
The objective was to drill a 7⅛-in vertical hole section at maximum ROP to the kick-off point with as few PDC bits as possible. A six-bladed MSI616UPX PDC bit equipped with 16-mm ONYX II cutters was selected for the test. The bit drilled the Travis Peak and bottomed in the upper portion of the Cotton Valley sand. The bit completed the section in one run at an average rate of 115.7 ft/h and was pulled at the KOP as planned. To benchmark the new cutter’s performance, four offset wells with a similar 7⅛-in vertical hole sections were selected for analysis. The investigation revealed that compared to the four-well offset average of just 59.4 ft/h the PDC with ONYX II cutters recorded a 95% increase in ROP. The reduction in rig-time usage lowered cost per foot by 44% saving the operator USD 100,600.

www.slb.com/onyxii

SMITH BITS
A Schlumberger Company
At-Bit Image Gamma and Inclination Allow Quick Interpretation for Steering Decisions

PathFinder technologies provide advanced measuring and imaging capabilities for accurate well positioning in North America shale play

**CHALLENGE**
Geosteering within a shale wellbore lateral to maintain and optimize position in the target zone.

**SOLUTION**
Use iPZIG* at-bit imaging gamma ray and dynamic inclination system with a customized drilling assembly to quickly interpret formation bed boundaries and PayZone Steering* real-time forward modeling to accurately geosteer the horizontal section.

**RESULTS**
Successfully geosteered the horizontal section, staying in the target zone 100% of the time.

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**Abrasive formation in North America shale**
An operator was drilling a lateral section in a very abrasive formation in a North America shale play. The abrasiveness caused excessive wear on the drilling equipment and required a specialized design. To geosteer within the lateral and stay in the target zone, the operator selected the MWD survey and total natural gamma ray (HDS-1L* fixed-collar directional service), coupled with the iPZIG system, based on its unique at-bit sensors that provide real-time bed boundary measurements.

The iPZIG system positions the image natural gamma ray and dynamic inclination measurements close to the bit to reduce the reaction time for making critical geosteering decisions and maintaining the wellbore in the targeted zone. Measurements of the bed boundary were characterized within the target interval, allowing for new calculation of apparent and true bed dip and direction. The iPZIG system’s close proximity to the bit enabled quick geosteering decisions to adjust the well trajectory and reduce risks while navigating through critical hole sections and maintaining the wellbore in the target zone.

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**CASE STUDY**

Steering interpretation based on iPZIG measurements correlated to PayZone Steering geologic model based on offset data.
CASE STUDY: PathFinder technologies provide advanced measuring and imaging capabilities for accurate well positioning in North America shale play

Advanced measuring, imaging, and modeling
When the borehole intersects a geologic feature, it appears as a sinusoid on the borehole natural gamma ray image. By fitting the sinusoid to the image data, apparent and true dip angle and dip direction can be quantitatively determined. Post processing of the image natural gamma ray using PayZone Steering forward modeling generates an earth model based on offset data. The iPZIG dynamic inclination and image gamma ray 8–16 sector data provides the drilling and geological teams with accurate real-time at-bit information. This allows for quick directional and geological interpretation of the wellbore to maintain the correct position within the defined target interval.

Accurate geosteering
The iPZIG at-bit measurements allowed for greater directional control and confidence in time-critical decision making relative to the wellbore trajectory to maximize in-zone exposure. Geological features observed from the iPZIG 8-sector real-time images aided in the geosteering interpretations. This in-depth information gained from the combined technologies helped the operator correctly determine the position and accurately direct the drilling, staying within the target interval.

Real-time static and dynamic normalization iPZIG image log with dip calculations.
High Build Rate RSS Service Saves Cimarex Energy 10 Days in Woodford Shale

PowerDrive Archer system increased ROP by 80% against offset wells

**CHALLENGE**
Drill high build rate horizontal well in shale play and increase wellbore quality.

**SOLUTION**
Use PowerDrive Archer* high build rate RSS to drill curve and PowerDrive X5* RSS to drill lateral section.

**RESULTS**
Increased ROP in curve by 80% compared to offset wells drilled with motors; reduced tortuosity in curve by 20%; drilled 4,353-ft lateral section to TD in a single run.

---

**Reduce tortuosity while drilling shale play**
Cimarex Energy Co. sought to drill a well in the Woodford shale play in the state of Oklahoma, USA, and wanted to reduce the wellbore tortuosity experienced in the previous four wells drilled in the field using positive displacement motor assemblies. The PowerDrive Archer RSS was chosen to drill the Kappus 1-22H well for its fully rotating design and ability to drill aggressive curves without sliding.

**Increase ROP and drill curve without sliding**
The PowerDrive Archer RSS drilled the 8¾-in curve section with an 8°/100 ft dogleg severity, showing an 80% increase in ROP versus the previous wells drilled using motors. The average ROP in the Kappus 1-22H curve section was 12.43 ft/h versus 6.65 ft/h for the four closest wells’ motor curve sections.

Use of the PowerDrive Archer RSS reduced wellbore tortuosity 20% compared with the curve section of the closest offset well drilled with a motor. The high quality of the curve section enabled the PowerDrive X5 RSS to drill the 4,353-ft lateral section to TD in one run.

The average ROP with the PowerDrive Archer RSS was 80% greater than the average ROP with motors in four previous wells.

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**Average ROP, ft/h**

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<td>ROP, ft/h</td>
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The average ROP with the PowerDrive Archer RSS was 80% greater than the average ROP with motors in four previous wells.
CASE STUDY: PowerDrive Archer RSS increased ROP by 80% against offset wells

Saved 10 days with improved drilling performance

The use of PowerDrive Archer and PowerDrive X5 fully rotating RSS to drill the curve and lateral sections of the well saved Cimarex Energy a total of 10 days. These significant time savings resulted from both an 80% increase in average ROP while drilling the curve section and a 20% reduction in wellbore tortuosity in the curve, which eased drilling operations in the lateral section.

Contact your local Schlumberger representative to learn more.

Use of the PowerDrive Archer RSS reduced wellbore tortuosity 20% compared with the closest curve section drilled with a motor.

The Kappus 1-22H well was drilled in 10 days less than the AFE plan.

www.slb.com/Archer
The Situation

Owing to rising disposal costs and tightening environmental restrictions, a Bakken Shale operator requested a proactive solution that would move it closer to a total closed-loop drilling operation. The operator’s past experience with closed-loop systems was costly and inefficient with no transparent value. What’s more, previous conventional attempts were ineffective in handling the considerable volume and size of the cuttings generated during high ROP surface drilling intrinsic of North Dakota’s Bakken Shale. Furthermore, the intermediate and production oil-base mud (OBM) and brine sections, respectively, also raised concerns of high ROP combined with the need to either reduce or increase mud density very quickly to manage the ECD and avoid losses or influxes.

Consequently, any closed-loop package design would be required to maintain density and other fluid properties in the water-base mud surface sections, the oil-base mud intermediate sections and the brine-base production interval without having to dilute and dispose of fluids.

The Solution

M-I SWACO immediately began to design a client-specific package that would meet the following requirements:

1. Mobility and timely installation
2. Winterization / harsh environment functionality
3. High-capacity dewatering and centrifugation
4. Spill prevention via an automation/control package
5. Barite recovery (preferentially removing low-gravity solids (LGS) in weighted systems)
6. Reduced liquid-on-cuttings (LOC) being discharged into the cuttings pit. This would cut closure costs if no free liquid is present.

Upon completion, the M-I SWACO customized OPTM-IZER closed-loop package was mobilized to two of the client’s drilling locations.

The Problem

Closed-loop drilling packages historically have been inefficient and too costly to move, while still doing little to reduce the disposal requirements of large waste streams. Traditionally, the large surface hole sizes in tandem with high sustained ROPs have impacted the capacity of earlier closed-loop packages to maintain fluid properties. Further, despite the inefficiencies, costs have been high compared to conventional treatment and disposal options.

The Situation

For its latest Bakken Shale campaign, the operator was unsure if a closed-loop package would adequately maintain fluid properties in the water-base mud surface hole, the oil-base intermediate interval as well as for the brine used in the production hole. This should be accomplished without incurring high dilution and disposal costs.

The Solution

The OPTM-IZER mobile closed-loop system was specifically designed and used on the operator’s two drilling sites in North Dakota’s Bakken Shale.
The Results

<table>
<thead>
<tr>
<th>Well #</th>
<th>Bit Size (in/mm)</th>
<th>Surface TD (ft/m)</th>
<th>Mud Wt. (PPG / SG)</th>
<th>Circulation Rate (GPM / LPM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Confidential</td>
<td>13.5 / 343</td>
<td>1835 / 559</td>
<td>8.7 / 1.04</td>
<td>750 / 2839</td>
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<tr>
<td>Confidential</td>
<td>13.5 / 343</td>
<td>1835 / 559</td>
<td>8.6 / 1.03</td>
<td>750 / 2839</td>
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<td>1835 / 559</td>
<td>8.5 / 1.02</td>
<td>750 / 2839</td>
</tr>
</tbody>
</table>

*All fluid from surface and tank cleaning slop was processed and stored in upright storage tanks for use on the next well.
*Tank cleaning and tank bottom processing were completed while running casing and the cement job was completed without impacting the drilling schedule.
*No issues were encountered during the casing run; no mud rings or drilling issues were reported while dewatering operations were used.

The initial installation was quick and easy, required only one truck and no crane picks, and initial operations commenced with only minor adjustments. The specially designed system effectively handled the cuttings volume regardless of the flow rates to the centrifuge packages. No dilution was required on the surface and all fluid was recovered and recycled for future surface holes. In keeping with the M-I SWACO commitment to continuous improvement, the performance on each surface hole improved over the preceding well.

Summary

During the operation, the M-I SWACO design team quickly modified the centrifuge discharge chutes to allow for higher than anticipated solids volume. Consequently, all initial OptM-IZER designs in the future will incorporate the larger discharge chutes. The Bakken Shale experience validated the OptM-IZER closed-loop package, in conjunction with additional recovery equipment if required, as efficient and cost-effective solution for zero-discharge drilling.

Questions? We’ll be glad to answer them.

If you’d like to know more about the OptM-IZER mobile closed-loop package and how it’s performing for our other customers, please call the M-I SWACO office nearest you.

The Bakken Shale campaign verified the capacity of the OptM-IZER ability to provide high-capacity dewatering and solids removal by means of dual fully variable-speed centrifuges, while also allowing for barite recovery and/or conventional barite stripping in the weighted sections. The performance of the system exceeded both internal and external expectations.

- Zero dilution required on surface
- Automation package kept pace, regardless of flow rates to the centrifuge packages
- All fluid was recovered and recycled for future surface holes.
- The OptM-IZER package in conjunction with the Fluids Management Plan allowed for the processing and treatment of tank-bottom waste from the rig pit cleaning operations during the casing and cementing operations.
MEGADRIL System Saves 1.5 Drilling Days and $15,000 Average Per Well in North Dakota

“The M-I SWACO MEGADRIL* system helped set the pace for drilling a 20,080-ft Bakken Shale horizontal in 27 days.”

D. Millhouse, M-I SWACO Regional Technical Services

Well Information
Location......................................................... North Dakota
Interval drilled ........................................ 8¾-in. directional hole drilled 2,287 to 11,258 ft (697–3,431 m)
Mud weight .................................................... 9.6 - 10.8 lb/gal (1.15–1.3 SG)
Pay zones .................................................... Bakken Shale
Casing size ..................................................... 7 in.
Maximum bottomhole temperature............... 230°F (110°C)
Maximum angle ........................................... >90 degrees

The Situation
These wells needed the maximum hole stability of an invert-emulsion fluid for drilling an 8¾-in. interval through the water-sensitive Charles and Kibby Lime formations. Additionally, losses had to be minimized while drilling the Mission Canyon formation, chiefly through precise control of Equivalent Circulating Densities (ECDs) prior to setting 7-in. casing. The lateral section would then be drilled with brine through the Bakken Shale.

The Solution
The MEGADRIL system has proven to be the fluid of choice on the continued Bakken-shale development for a major operator in the Williston Basin. The MEGADRIL system, using a one-drum emulsifier package, MEGAMUL, continues to provide a flat rheology along with reduced gel strengths and low plastic viscosities and yield point. The system delivers excellent Rates of Penetration (ROP), allowing maximum hole cleaning and reduced ECD. The system was run with an Oil-to-Water Ratio (OWR) of 75:25 instead of the traditional 80:20, reducing the use of diesel base oil while maintaining an excellent rheological profile.

The Results
• The initial ROP averaged between 250– 300 ft/hr (76– 91 m/hr), with a 14-day average of 640 ft/day (195 m/day) while drilling the intermediate hole section.
• Minimal amounts of lost mud through the Oil-Base Mud (OBM) interval, including the Mission Canyon formation, have helped reduce overall drilling fluid costs. The contributing attributes of a flat, stable rheology allows effective ECD management and pressure control.
• The directional curve was built to 90 degrees for the lateral work in the Bakken formation; 7-in. casing was run and cemented through the curve with full returns throughout the job.
The Details
The 2008 MEGADRIL System Results:

- Drilling days on every rig have been reduced from an average of 9.1 days in the OBM interval to 7.6 days.
- Overall, yearly OBM interval costs have decreased from $6.43 to $5.82/ft, based on a 53-well comparison with the MEGADRIL system being used on the majority of wells in 2008.
- The 75:25 OWR decreased average per-well use of diesel by 240 bbl (38 m³) for tangible cost savings per well of approximately $15,000 compared to typical invert formulation with an 80:20 OWR.
- Average total well days have also fallen from 20.23 days to 14.91, an improvement of 5.3 days.

![Drilling Days Chart](chart.png)
Questions? We’ll be glad to answer them.
If you’d like to know more about the MEGADRIL system and how it’s performing for our other customers, please call the M-I SWACO office nearest you.
MicroScope Resistivity and Imaging Enable Successful Completion in Complex Shale Formation

Real-time high-resolution images accurately identify formation dip, faults, and natural fractures for placement of lateral within Niobrara target zone

**CHALLENGE**
Maximize wellbore intersection with natural fractures to optimize oil recovery from highly faulted zone in Niobrara shale.

**SOLUTION**
Use real-time images from MicroScope* resistivity- and imaging-while-drilling service to confirm borehole position relative to target formation and identify and characterize natural fractures.

**RESULTS**
Successfully placed horizontal lateral within predefined target interval and completed well for production.

Real-time image acquisition and interpretation enabled the operator to understand the complexity of the reservoir and to optimize lateral well placement.

**Intersect maximum number of natural fractures**
An independent operator in the western US planned to drill a horizontal lateral to produce oil from a complex reservoir in the Niobrara shale formation. Prior to drilling the lateral, a complete openhole log, including images from an FMI* fullbore formation microimager, was acquired in a vertical well to identify the best horizontal target interval, confirm the presence of natural fractures, and determine the maximum horizontal stress orientation.

This information was used to select the direction the horizontal lateral should be drilled to maximize the number of natural fractures it would intersect and facilitate the development of a complex fracture network during stimulation. To enhance reservoir understanding and optimize oil recovery, the operator needed to correlate and confirm the position of the borehole relative to the target formation while drilling.

**Optimize wellbore placement in highly complex reservoir**
MicroScope service provided high-resolution electrical borehole images, azimuthal gamma ray measurements, and multidepth formation resistivity measurements in real time. This information, together with mud gas data, was used to constantly update the structural model and determine wellbore trajectory relative to the target interval in the highly faulted reservoir.

When the lateral had been drilled to about three-quarters of its planned length, it crossed a major fault plane with a significant fault throw, which placed the lateral below the target formation within just a few hundred feet of TD. To improve reservoir exposure, the operator decided to drill a sidetrack from the existing lateral.

* Schlumberger proprietary technology.
**Improve structural understanding**

The improved structural understanding that interpretation of the real-time MicroScope images provided made steering the sidetrack less demanding than steering the original lateral. While drilling the sidetrack, real-time MicroScope images revealed that there was less structural change than there had been in the first half of the lateral. Constant updating of the structural model based on real-time data enabled successful placement within the predefined target interval and well completion.

Contact your local Schlumberger representative to learn more.
Spear Bit Sets ROP Record, Saves USD 46,780 Drilling in Eagle Ford Shale

Optimized bit drills curve and lateral in one run

**CHALLENGE**
Drill the 8¾-in curve and lateral sections for an Eagle Ford shale well in one run while maintaining good directional control in the curve and high ROP in the lateral.

**SOLUTION**
Run the innovative Spear* steel-body PDC drill bit on a PathFinder positive displacement motor.

**RESULT**
The operator saved USD 46,780 in rig time by drilling the curve and lateral in one run at a record ROP.

---

**Balanced PDC bit for directional control and high ROP required**
Operators working the Eagle Ford shale play in south Texas have experienced costly NPT as a result of multiple runs needed to drill curve and lateral hole sections. The operator wanted a PDC drill bit that would increase ROP and total footage capabilities in the 8¾-in curve and lateral hole sections while providing good directional control at maximum penetration rates. With this request, a familiar technological dilemma emerged: PDC bits designed for curve sections deliver strong build capabilities and predictable directional control, but often at the expense of acceptable ROP. Alternatively, bits intended for laterals produce high ROP but with lesser directional control capabilities. This technology gap required the choice between steerability performance and high ROP.

**Smith Bits Solution: Spear PDC**
To solve this dilemma, engineers tailored specific Spear PDC steel-body technologies to solve the application issue. Using IDEAS* integrated drillbit design platform, engineers determined PDC bit body profile plays a major role in efficient cuttings removal for fast ROP. Based on knowledge gained from the in-depth analysis and field experience, Smith Bits developed a specific Spear PDC bit optimized for the Eagle Ford shale drilling application with the following technology platform:

- Optimized hydraulics to clean debris from bit face and expose cutter edges to formation maximizing ROP
- Bullet-shaped body allows cuttings to sweep around bit and into junk slots
- Reduced body diameter increases distance between the borehole wall allowing the bit to pass over or through a cuttings bed without blade packing or nozzle plugging
- Bit’s steel composition enables increased blade height and reduced width increasing junk slot area

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Record setting Spear 8¾-in SDI513 steel-body PDC technology specifically designed for Eagle Ford Shale curve and lateral drilling applications
Spear case study well with total footage and ROP offset comparisons, Eagle Ford Shale - Webb County, Texas

**Value delivered**

Spear 8¾-in SDi513 on a PathFinder steerable motor drilled 6,904 ft of curve and lateral hole section in one run at a record ROP of 64.83 ft/h. This represents the fastest curve and lateral run for the operator in the Eagle Ford shale play. Based on a comparison with the best offset run, the new Spear bit saved the operator USD 46,780 in rig time. Compared to the next, four best offsets, the run saved significantly more rig time and overall drilling costs associated with multiple trips/bits required to complete curve and lateral hole sections.
PowerDrive Archer RSS Increases ROP by 85% in Eagle Ford Shale Play

High build rate RSS improves drilling performance, eases casing running

CHALLENGE
Improve drilling performance in the Eagle Ford shale play.

SOLUTION
Use PowerDrive Archer* high build rate RSS to maximize ROP and reduce cost per foot.

RESULTS
Increased curve ROP by 85%; reduced cost per foot by 27% versus conventional motor BHAs.

With the fully rotating PowerDrive Archer RSS, average curve ROP was increased by 85% and tortuosity in the curve and lateral was reduced, resulting in casing being run to bottom without any rotation.

Horizontal drilling in the Eagle Ford shale
The Eagle Ford formation—situated in South Texas, USA—has become one of the hottest shale plays in recent times. Many operators are drilling hundreds of horizontal wells to target this reservoir located below the Austin chalk.

These wells are typically drilled with conventional motors, and a high percentage of slide drilling is required to build the curves up to 10°/100 ft. This requirement results in drilling and completion inefficiencies as ROP is reduced, and there are subsequent casing running problems because of high wellbore tortuosity in the curve and lateral sections.

High build rate RSS outperformed conventional motors in same play
PowerDrive Archer RSS has been introduced to drill these high build rate wells, which were previously only possible with motors. The fully rotating RSS immediately delivered two key improvements: In a multiwell project, average curve ROP was 85% faster in the 10 wells drilled with PowerDrive Archer RSS than those drilled with conventional motors. And tortuosity in the curve and lateral was reduced; the clients found that, for the first time, casing could be run to bottom without rotation.

Average ROP with PowerDrive Archer RSS was 85% faster than conventional motors, and the cost per foot was significantly lower.

To date, PowerDrive Archer RSS has drilled 17 wells and more than 30,000 ft in the Eagle Ford, with many more wells planned.

Contact your local Schlumberger representative to learn more.

*Mark of Schlumberger
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Optimizing Stimulation and Reservoir Characterization Using LWD Measurements in the Eagle Ford Shale

An independent operating company gains in-depth understanding of the Eagle Ford Shale to optimize its stimulation program

**CHALLENGE**
Well placement, reservoir characterization, completion design, and stimulation optimization of a horizontal well in the Eagle Ford Shale.

**SOLUTION**
EcoScope* and sonicVISION* measurements to steer the lateral in real time, perform structural interpretation using azimuthal borehole images, and derive reservoir and geomechanical properties to optimize completion design and enhance stimulation treatment.

**RESULTS**
Real-time acquisition, interpretation, and integration of well measurements, which helped the operator to prevent unexpected drilling events, evaluate the reservoir, and optimize the stimulation operation.

**The benefits of LWD data**
An independent operator drilling a new well in Webb County, Texas, planned to extend the horizontal section to an area beyond 3D seismic coverage and to log the entire lateral while drilling. LWD measurements were transmitted in real time to help ensure optimal placement of the lateral within the geologic structure and to evaluate the reservoir. Schlumberger provided the resources to acquire, interpret, and integrate logging-while-drilling measurements to influence the stimulation program in real time.

**Interpreting LWD measurements for Eagle Ford characterization**
To perform shale gas reservoir characterization along the lateral, the operator used combinations of the EcoScope multifunction logging-while-drilling service (including density images and spectroscopy), the TeleScope* high-speed telemetry-while-drilling service, and the sonicVISION sonic-while-drilling tool.

*EcoScope and sonicVISION data revealed dip changes in Eagle Ford layers. The borehole image enabled the identification of a fault near the toe of the lateral.*
With the InterACT* connectivity, collaboration, and information system, real-time data was transmitted from the rig site to Schlumberger OSC* interactive drilling operations and Data & Consulting Services (DCS) scientists and engineers. This remote transmission allowed the operating company personnel to interpret LWD data and monitor drilling mechanics data in real time.

The final interpretation enhanced mineralogy description, structural mapping, and understanding of reservoir and geomechanical properties for integrated shale gas characterization.

**Integrated shale gas characterization for stimulation practice**

Based on this robust evaluation suite, Schlumberger was able to recommend an optimized completion design by placing the perforation clusters guided by reservoir and geomechanical properties. Furthermore, the stress profile and mineralogy from the evaluation were used to optimize the fracturing strategy.

Close coordination of this integrated workflow of data gathering, processing, and analysis helped in providing final recommendations in time for implementation and execution.

LWD images and stress data helped an independent operating company optimize perforation placement and fracture stages.
SEECO Drills First High Build Rate RSS Wells in Fayetteville Unconventional Gas Reservoir

PowerDrive Archer service delivers highest build rates from an RSS in 8¾-in hole

CHALLENGE
Overcome poor hole cleaning and stuck pipe incidents that occur while sliding with positive displacement motor; increase build rates in upper Fayetteville.

SOLUTION
Use PowerDrive Archer* high build rate, fully rotating RSS to kick off from vertical, build curve, and land the well in the reservoir while drilling a smooth, clean wellbore.

RESULTS
Kicked off from vertical; delivered build rates greater than 14°/100 ft; successfully landed in reservoir with late change to TVD because of geological uncertainty; drilled 1,000 ft of lateral section.

Delivering high build rate well profiles with a RSS
Southwestern Energy Corporation (SEECO) drills and completes more than 600 horizontal wells per year in the Fayetteville shale gas play. While drilling for unconventional gas, SEECO has made significant production rate increases by extending horizontal lateral lengths. To achieve these results, well profiles often have build rate curves of 10°/100 ft or more. Previously, these wells were beyond the reach of conventional RSS tools and were drilled with positive displacement motors. This resulted in some challenging drilling problems, such as low ROP, poor hole cleaning, and stuck pipe incidents.

PowerDrive Archer high build rate RSS offered a solution delivering this aggressive well profile. And in delivering curves previously only possible with motors, the tool also provided the benefits of a fully rotating RSS with high ROP and wellbore quality.

The first well profile involved a kick off from vertical into a continuous 10°/100 ft build section to land horizontally in the Fayetteville shale. The vertical kickoff was achieved without issue and the curve drilled successfully—with PowerDrive Archer RSS delivering greater than 10°/100 ft in the troublesome upper Fayetteville, where motors had previously struggled. The well was landed within 0.5 ft of the target and casing was run smoothly.
**CASE STUDY:** PowerDrive Archer service delivers highest build rates from an RSS in 8 7/8-in hole

More than 14°/100 ft build rate and successful lateral section
SEECO chose to use PowerDrive Archer RSS once again for the second well as it required a vertical kickoff, build rates greater than 14°/100 ft, and a lateral section through the reservoir. In the second well, a maximum build rate of greater than 14°/100 ft was achieved and a 1,000-ft near-horizontal lateral section completed.

This tool increased reservoir exposure to enable SEECO to achieve its goals of increasing production rates by maximizing horizontal lateral sections. This was achieved by hitting the reservoir sooner and drilling farther in the horizontal section.

Contact your local Schlumberger representative to learn more.
ROP Increased 67.7% in High Temperature Haynesville Shale

Productive drilling with PowerDrive X5 RSS positions lateral gas well in best place in less time

CHALLENGE
Increase ROP in high-temperature Haynesville shale gas well lateral with consistent circulating temperatures up to 300 degF.

SOLUTION
Use PowerDrive X5* rotary steerable system in program correctly engineered for productive drilling.

RESULTS
Increased ROP 67.7%; Drilled 1,175 ft in first PowerDrive X5 run; Provided high-quality wellbore for running completions.

Using the PowerDrive X5 RSS increased ROP in the Haynesville shale more than 67%.

Improve drilling efficiency
An operator was drilling a lateral for a gas well in the Haynesville shale formation in northwest Louisiana, USA. The directional plan called for holding inclination at 89.80° while turning the azimuth to 2.15° at 1°/100 ft, then holding that inclination and azimuth to TD. Consistent circulating temperatures were expected to be up to 300 degF, and possibly higher.

The operator attempted to achieve the directional objective with a steerable motor assembly from a different service provider, but the lateral section proved to be a struggle. After several days of drilling, it became apparent that making the 1°/100-ft turn with the motor, while possible, could be done only at a very low ROP—4 ft/h. That was unacceptable to the operator, so Schlumberger was called to finish drilling the lateral.

Position lateral in best place
After a 4.75-in PowerDrive X5 RSS was tripped into the hole and drilling resumed, it was found that the target zone was not flat and extra steering was required to position the lateral in the best place. Implementing a program correctly engineered for productive drilling, the fully rotating PowerDrive RSS delivered the doglegs needed to stay in the zone—better than required—and finished the lateral, all at a consistent ROP of 16 to 17 ft/h.

The average ROP of 16.93 ft/h achieved with the PowerDrive X5 RSS was 67.7% higher than the steerable motor’s average ROP of 10.10 ft/h.
Reach TD in less time
The first run with PowerDrive X5 RSS was 1,175 ft at a peak of 17 ft/h, showing significant improvement in drilling efficiency and increased ROP. The operator reached TD in much less time than would have been required if drilling the lateral entirely with the steerable motor. Average ROP achieved with the PowerDrive X5 system was 16.93 ft/h—an increase of more than 67% over the steerable motor’s average ROP of 10.10 ft/h. In addition, the RSS provided a high-quality wellbore to facilitate running completions.

Contact your local Schlumberger representative to learn more.
Spear Drill Bit Saves USD 365,000 in Haynesville Shale Well

Optimized bit drills curve and lateral in one run

CHALLENGE
Drill 6¾-in curve and lateral sections of a Haynesville Shale well in one run, with good directional control and high ROP.

SOLUTION
Run innovative, application-specific Spear® shale-optimized steel-body PDC drill bit.

RESULT
Saved 124 h of rig time and USD 365,000 by drilling both intervals in one run, with record horizontal ROP.

Shale bit with good directional control and ROP required
An operator active in the Haynesville Shale (Texas and Louisiana) wanted to reduce the number of days and trips required to drill the 6¾-in production interval, by drilling both the curve and lateral sections in one run. Previous bit designs were aimed at either the curve or the lateral, necessitating a trip to change out the bit and adjust the bend angle. Bits that target the curve section have strong build tendencies and predictable toolface control, but often deliver low ROP in the lateral. Conversely, bits for the lateral section are built for aggressive, fast ROP, but increase the risk of improper build rates in the curve section. The use of two bits and extra trips meant higher field development costs.

Engineers needed to design a PDC bit that could be efficiently run on a positive displacement motor (PDM) with a lower bend angle while achieving the desired build rates (8° to 14°/100 ft), ensure good directional control, and deliver high ROP in the lateral. Long lateral drilling in shale plays presents additional challenges such as cuttings accumulation at the bottom of the well, which impedes access to fresh rock and results in low ROP, packed blades, nozzle plugging, and stick/slip.

Application-specific bit designed
A Smith Bits team consisting of field engineers, design engineers, and hydraulics experts was assembled to design a bit that would achieve the primary goal of drilling the entire 6¾-in production interval in one run. The team had access to several proprietary modeling and database tools, including:

- IDEAS® integrated drillbit design platform
- i-DRILL® engineered drilling system design for BHA modeling
- YieldPoint RT® drilling hydraulics and hole cleaning simulation program
- DRS® drilling record system, a collection of nearly 3 million bit runs.

Record-setting Spear 6¾-in SDi611 steel-body PDC drill bit, specifically designed for Haynesville horizontal shale drilling.

The new 6¾-in SDi611 bit has been run on steerable PDMs with the following operating parameters:
- PDM speeds from 0.52 to 1.02 rev/galUS
- motor bend-angles from 1.5° to 2.6°
- various BHA configurations
- flow rates ranging from 200 to 260 galUS/min
- weight on bit (WOB) ranging from 2,000 to 20,000 lbf
- mud weights from 14.5 to 17.0 lbm/galUS
CASE STUDY: Spear bit delivers steerability and record ROP, Haynesville Shale

The operator provided valuable BHA data, mud properties, and offset run information for focusing the design. Close cooperation between the various groups resulted in new PDC bit technology, the Spear 6¾-in SDi611 drill bit, which provides a good balance between superior directional control and fast ROP.

USD 365,000 saved on a single well
Spear 6¾-in SDi611 shale-optimized steel-body PDC bit, together with a 2° fixed bend steerable motor, drilled the 6,063 ft of curve and horizontal intervals in one run, setting a new Haynesville horizontal ROP record of 49.7 ft/h. Although there are a few faster lateral runs, no other bit had drilled the entire curve and lateral sections at that high rate. The bullet-shaped steel body and various other design features effectively combat buildup of cuttings in front of the bit and the resulting adverse effects.

Based on comparisons with two direct offset wells, the total drilling time was reduced by 124 h. The improved performance saved the operator USD 365,000 in rig-time and bit costs, and shortened time to production, allowing more wells to be drilled in a given period.
**CASE STUDY**

**Spear Drill Bit Saves USD 175,000 and 2.7 d of Rig Time in Marcellus Shale Well**

**Optimized bit drills curve and lateral in one run**

**CHALLENGE**

Drill 7 7/8-in curve and lateral sections of a Marcellus Shale well in one run, with good directional control and high ROP. Reduce NPT caused by motor and MWD failures.

**SOLUTION**

Run innovative, application-specific Spear* shale-optimized steel-body PDC drill bit.

**RESULT**

Saved 2.7 d of rig time and USD 175,000 by drilling both intervals in one run. Eliminated downhole equipment failure by reducing vibration.

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**Shale bit suitable for both curve and lateral sections required**

EOG Resources wanted to reduce the number of days and trips required to drill the 7 7/8-in curve and lateral sections of wells in the Marcellus Shale, Pennsylvania, by efficiently drilling both sections in one run. Previous bit designs were aimed primarily at either the curve or the lateral, necessitating a trip to change out the bit and adjust the motor bend angle at the end of the curve section. Bits that target the curve section have strong build tendencies and predictable toolface control, but often deliver low ROP in the lateral. Conversely, bits for the lateral section are built for aggressive, fast ROP, but increase the risk of improper build rates in the curve section. The use of two bits and extra trips meant higher costs. In addition, EOG wanted to reduce the NPT caused by motor and MWD failures.

Engineers needed to design a PDC bit that could be run on a positive displacement motor (PDM) with a lower bend angle, allowing rotation and a high ROP in the lateral. At the same time, the bit had to be capable of achieving the desired build rates (8° to 16°/100 ft) and ensuring good directional control in the curve section. Long lateral drilling in shale plays presents additional challenges such as cuttings accumulation at the bottom of the well, which impedes access to fresh rock and results in low ROP, packed blades, nozzle plugging, and stick/slip.

**Application-specific steel-body PDC bit designed**

A Smith Bits team consisting of field engineers, design engineers, and hydraulics experts was assembled to design and manufacture a bit that would achieve the primary goal of drilling the entire 7 7/8-in production interval in one run.

The team had access to several proprietary modeling and database tools, including:

- IDEAS* integrated drillbit design platform
- DBOS* drillbit optimization system for rock strength analysis
- YieldPoint RT* drilling hydraulics and hole cleaning simulation program
- DRS* drilling record system, a collection of nearly 3 million bit runs.

EOG provided valuable BHA data, mud properties, and offset run information for focusing the design. Close cooperation between the various groups resulted in new PDC bit technology, the Spear 7 7/8-in SD1513 drill bit, which provides a good balance between high build rates, superior directional control, and fast ROP, significantly reducing operating costs.

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**Innovative Spear 7 7/8-in SD1513 steel-body PDC drill bit, specifically designed for Marcellus horizontal shale drilling**
CASE STUDY: Spear bit delivers steerability and high ROP, Marcellus Shale, Pennsylvania

The new 7 7/8-in SDi513 bits have been run on steerable PDMs with the following operating parameters:
- PDM speeds from 0.28 to 0.66 rev/galUS
- typical PDM configuration
  - 6½ in, 4.5 lobe, 7.5 stage PDM (0.66 rev/galUS)
  - 6½ in, 7.8 lobe, 4.8 stage PDM (0.66 rev/galUS)
- motor bend angles from 1.5° to 2.6°
- typical BHA: bit, PDM, universal bottom hole orientation (UBHO) sub, nonmagnetic drill collar, and nonmagnetic flex joint
- flow rates ranging from 350 to 500 galUS/min
- weight on bit (WOB) ranging from 2,000 to 20,000 lbf
- mud weights in the curve from 9.7 to 10.3 lbm/galUS
- mud weights in the lateral from 10.3 to 11.3 lbm/galUS

USD 175,000 saved on a single well
Spear 7 7/8-in SDi513 shale-optimized steel-body PDC drill bit, together with a fixed bend steerable motor, drilled the 6,241 ft of curve and horizontal intervals in one run, eliminating costly trips for PDM adjustments and bit changes after landing the curve. Reduced vibration also solved the problem of PDM and MWD failures. The bullet-shaped steel body and various other design features effectively combat buildup of cuttings in front of the bit and the resulting adverse effects.

Based on comparisons with the offset average, total drilling time was reduced by 2.7 d. The improved performance saved EOG USD 175,000 in rig-time and bit costs, and shortened time to production, allowing more wells to be drilled in a given period.
Over USD 1 Million Saved on Marcellus Shale Wells

High build rate rotary steerable system cuts drilling time per well 10 days and delivers clean, high-quality wellbores for smooth casing running

CHALLENGE
Reduce cost and improve quality of complex 3D wells targeting Marcellus shale.

SOLUTION
Drill with PowerDrive Archer® high build rate rotary steerable system (RSS) instead of positive displacement motor (PDM).

RESULTS
- Increased ROP 170%.
- Reduced drilling time per well from 18 days to 8 days.
- Saved over USD 1 million.

Reducing drilling time with the PowerDrive Archer RSS saved over USD 1 million.

Reduce drilling time and cost
The Marcellus shale play, one of the biggest unconventional shale plays in the US, contains an estimated 363 trillion cubic feet of recoverable gas—enough to supply US consumption for at least 14 years. At first, the play was developed using conventional vertical wells, which had low returns. Now, to extract the hydrocarbons at economically viable rates, horizontal wells are drilled from multiwell pads and completed with multistage fracture stimulation of the lateral. These wells are challenging to drill due to surface pad collision risks, complex 3D profiles with planned curvature rates of 8°/100 ft, geological uncertainty and formations that make directional control difficult.

In this well, PowerDrive Archer RSS was able to kick off from vertical, drill a 3D curve with more than a 100° change in azimuth, and hold an unplanned tangent section made necessary by a landing point change of more than 70 ft. The RSS quickly built to 16°/100 ft once the geological marker was found, and then soft landed the well from 85° to 90° at a 2° build rate.

Drilling
CASE STUDY: High build rate rotary steerable system cuts drilling time in Marcellus shale

Use of the PowerDrive Archer RSS enabled the operator to reduce overall drilling time from the 18 days required with the PDM in Well 1 to just 8 days for Well 11—the tenth well drilled with the RSS.

Traditionally, the well’s vertical section was air-drilled and a 9¾-in casing shoe was set. Then the 8¾-in hole section was kicked off, built, and landed on the Marcellus shale using a PDM. This required sliding the PDM for much of the interval, resulting in a low ROP, poor hole cleaning, and wellbore tortuosity. Trips made to adjust the motor’s bent housing when geological uncertainties were encountered further increased drilling time and cost. An operator planning a multiwell campaign in the Marcellus shale play wanted to improve ROP and hole quality—and reduce drilling time.

Eliminate flat time and improve drilling efficiency

Breakthrough technology developed by Schlumberger—the PowerDrive Archer high build rate RSS—enabled the operator to meet the drilling challenges and achieve those objectives. The PowerDrive Archer RSS, a true hybrid that combines push-the-bit and point-the-bit steering, can drill vertical, curve, and lateral wellbore sections in one run, eliminating flat time and improving drilling efficiency. In curve sections, this unique RSS delivers continuous, reliable, and repeatable build rates; and in vertical and lateral sections, automatic inclination hold can be engaged to maximize ROP.

Establishing clear focal points and communication channels between the operator and Schlumberger prior to starting the campaign resulted in a smooth operation. The first well was drilled with a PDM, to serve as a benchmark. All wells after that were drilled with the PowerDrive Archer RSS. Typically, these wells were kicked off from vertical with a long turn in azimuth of 90° or more to line up with the target while simultaneously building inclination at planned build rates up to 8°/100 ft. Due to geological uncertainties approaching the landing point, higher build rates of up to 17°/100 ft were sometimes required to land the well—something easily accomplished by the PowerDrive Archer RSS without any need to trip out of the hole.
**CASE STUDY:** High build rate rotary steerable system cuts drilling time in Marcellus shale

Reach TD in less time
The operator saved more than USD 1 million on the first 10 wells drilled with the PowerDrive Archer RSS. The ability of the true-hybrid RSS to kick off from vertical, deliver 2D and 3D curves with build rates of up to 17°/100 ft, drill tangent sections, and land wells on target in a single run enabled the operator to reduce overall drilling time from the 18 days required with the PDM in the benchmark well to just 8 days on the tenth well drilled with the PowerDrive Archer RSS. Average ROP increased 170%, compared to ROP with the PDM; and eliminating the sliding required with a motor resulted in clean, high-quality wellbores that allowed smooth casing runs.

Contact your local Schlumberger representative to learn more.

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Days saved | Well 1 (PDM) | Well 2 | Well 3 | Well 4 | Well 5 | Well 6 | Well 7 | Well 8 | Well 9 | Well 10 | Well 11
---|---|---|---|---|---|---|---|---|---|---|---
USD saved | 0.00 | 0 | 13,016 | 166,303 | 70,442 | 146,782 | 84,518 | 639 | 135,211 | 204,890 | 27,558 | 214,428
Cumulative days saved | 0.00 | 0.22 | 2.77 | 1.17 | 2.45 | 1.41 | 0.01 | 2.25 | 3.41 | 0.46 | 3.57
Cumulative USD saved | 0 | 13,016 | 166,303 | 236,745 | 307,187 | 453,969 | 538,487 | 601,406 | 736,217 | 911,097 | 1,125,525

Fast, efficient drilling with the PowerDrive Archer RSS saved more than USD 1 million.
Real-Time Measurements Optimize Marcellus Shale Well Placement

Marcellus shale operator repeatedly places long lateral in richest target zone

**CHALLENGE**
Land operator’s first Marcellus Shale production well in the best reservoir portion of the Marcellus Shale and place a 4,000-ft lateral section in a narrow target interval.

**SOLUTION**
Combine real-time geosteering using EcoScope* measurements with azimuthal images and interpretation support from Schlumberger well placement engineers.

**RESULTS**
Landed well 12 to 14 ft below the top of the target interval; lateral sections steered using EcoScope measurements remained within the target.

Maximize contact with the reservoir target
An independent operator worked with Schlumberger to interpret wireline logs from vertical wells to understand the heterogeneity of distinct layers within the Marcellus Shale. The operator wanted to place its first Marcellus Shale well in a 57-ft [17-m] thick target interval it had mapped using offset well logs and seismic data, noting that the Marcellus dips as much as 2.5° near the potential well location.

The company decided to log while drilling to correlate real-time measurements with seismic data to steer a long lateral section within the target interval. A Schlumberger well placement engineer was engaged to interpret the real-time logging data and advise the operations team from the operating company.

Steer within dipping beds
The well was landed in the middle of the defined target, 12 ft shallower than planned. To drill the horizontal section, measurements and density images from the EcoScope multifunction logging-while-drilling service were used to steer the well parallel to the target beds.

Daily analysis of measurements acquired while drilling helped the operating company place a long lateral with a clear understanding of drilling mechanics, borehole stability, and formation evaluation, which contributed to successful well completions.

Shale Gas
The density images were also used to map individual shale beds. A Schlumberger well placement team worked with the operating company to match the real-time measurements and derived dips from density images with dynamic synthetic models to provide visualization for steering. This cooperation helped improve well placement because the dip of the Marcellus was found vary locally, averaging less than 1°. The lateral was placed within a 30-ft [10-m] stratigraphic window that is only 18 ft thick when converted to true vertical thickness.

sonicVISION* data acquired while drilling was of good quality and showed no obvious indications of open fractures. This data was used to derive rock mechanical properties along the lateral, which revealed significant variations in the minimum horizontal stress. Using Schlumberger LWD Shale Gas Completion Optimization Solutions, perforations were designed in zones of lowest stress, low clay content, and high free gas content along ten hydraulic fracturing stages. This analysis helped the operating company design the stage intervals and pinpoint perforation clusters to target intervals with the optimal properties for hydraulic fracturing.

Optimize future wells

The well penetrated the desired target interval and proved to be a good producer. The excursions of the lateral outside the target confirmed that even subtle dips in the Marcellus Shale should be anticipated when planning wells. By penetrating a substantial section within the target, the operating company optimized the completion for maximum recovery from the reservoir.

The superior production from the new well and wells drilled later using the EcoScope service showed the value of advanced measurement technology for placing wells in the most productive zone. The operating company committed to a multiwell drilling campaign incorporating the EcoScope service and Schlumberger well placement engineering support.

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Consulting Services Identifies Key Technologies to Drill and Evaluate Wells in the Niobrara Formation

Expert analysis of high-tier logs and real-time data targets the most productive zone in unconventional oil reservoir

**CHALLENGE**
Determine key production drivers in Niobrara formation, target interval of highest reservoir quality, and accurately geosteer the horizontal lateral within that zone.

**SOLUTION**
Engaged Schlumberger DCS to recommend and run a suite of fit-for-purpose tools to characterize the reservoir, guide real-time geosteering, and optimize completions.

**RESULTS**
Identified the 10-ft interval of greatest potential, stayed in zone for entire length of the 3,000-ft lateral, and modified completion design to maximize well performance.

“Schlumberger DCS was very easy to work with and provided the expert guidance needed to successfully complete our first three horizontal wells within the desired stratigraphic interval.”

Independent Operator, Denver-Julesberg basin

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Making sure to get it right—from the start

In the fall of 2010, a small operator in the Denver-Julesberg basin of Colorado began its first horizontal drilling campaign in the Niobrara formation, an unconventional oil reservoir with four laterally continuous chalk units. Based on historical drilling data, the operator knew the “B” unit was the primary target in this area, but did not know what portion of the 36-ft zone would be most productive.

The operator needed to understand the reservoir’s major production drivers—petrophysics, mechanical properties, natural fractures, structural complexity, and so on—and use that knowledge to optimize drilling and completions not only for the first well, but for the whole campaign.

Since the company’s internal resources were limited and they were relatively unfamiliar with the area, decision makers wanted to shorten the typical learning curve associated with entering any new unconventional play. They wanted to make sure they got it right, from the very beginning. To do so, they turned to the seasoned geotechnical consultants of Schlumberger Data & Consulting Services (DCS).

**Accurately quantifying the key production drivers**
The client approached DCS because of its reputation consulting on unconventional projects in the Denver-Julesberg basin. Based on the operator’s needs, DCS recommended a suite of high-tier, fit-for-purpose logging measurements for the pilot hole and a geosteering solution for the lateral.

Schlumberger Platform Express® integrated wireline logging, ECS® elemental capture spectroscopy, and CMR® combinable magnetic resonance tools accurately quantified reservoir quality—mineralogy, porosity, permeability, and saturation. Borehole images from FMI® fullbore formation...
Microimager helped unravel natural and induced fractures. And acoustic behavior information from Sonic Scanner* acoustic scanning platform characterized the Niobrara’s stress state and other mechanical properties.

Expert processing, analysis, interpretation, and integration of field log data by DCS geoscientists and engineers yielded a better understanding of the target reservoir in the area. In the process, they identified a 10-ft interval in the middle of the Niobrara “B” unit as the zone of greatest potential. After determining where to drill the horizontal lateral, the team’s next challenge was to keep the wellbore within that more-productive zone as much as possible.

**Targeting the productive zone, optimizing completions**

Because of the formation’s extensive lateral continuity, Schlumberger recommended its new MicroScope* advanced resistivity and imaging-while-drilling service to guide geosteering operations. A DCS well placement engineer interpreted resistivity images in real time to construct an initial cross-section of the target interval and to determine when the borehole was climbing or dropping. As a result, the well successfully remained in the 10-ft zone of highest reservoir quality for more than 3,000 ft.

After drilling was completed, further processing and interpretation of high-resolution MicroScope imagery revealed detailed bedding and fracture intensity, as well as the strike and dip of open and healed natural fractures. This refined the structural section along the well path, enabling engineers to optimize the original completion design in three ways: (1) by combining similar lithologies, (2) by avoiding the placement of packers in areas of intense fracturing, and (3) by managing fluids and pump rates to prevent excessive leakoff and achieve near-wellbore connectivity.

Finally, results from this initial well empowered the operator to make more informed decisions about additional wells in its ongoing Niobrara drilling program.

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**CASE STUDY: Target the most productive zone in Niobrara reservoir**

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**Targeting the productive zone, optimizing completions**

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Advanced Logging Technology Reveals the Most Productive Zones in Woodford Shale Wells

Integration of LWD and production logging measurements identifies the most productive zones of the shale reservoir in Oklahoma

**CHALLENGE**

Optimize placement and production from future wells in the Woodford Shale by identifying and perforating the most prolific reservoir rock.

**SOLUTION**

Integrate LWD along the lateral with neutron, density, and resistivity data from a vertical offset well to identify the most productive reservoir intervals. Refine mapping of reservoir zones using LWD and identify sweet spots using Flow Scanner® horizontal and deviated well production logging system.

**RESULTS**

Integration of EcoScope®, Platform Express®, and Flow Scanner data determined that 90% of gas came from perforations placed in zones identified as most productive.

Mapping reservoir intervals

An operator performed an LWD operation on a 4,000-ft [1,220-m] lateral in the Woodford Shale. The measurements were run to understand how the formation dip changes laterally and how the reservoir properties vary across the vertical layers. Working with engineers from Schlumberger Data & Consulting Services, the operator integrated offset vertical “triple combo” neutron, density, and resistivity measurements with measurements obtained with the EcoScope multifunction LWD service to map nine distinct layers in the Woodford Shale with a thickness of 220 ft [67 m].

Integrating measurements to identify high-quality reservoir intervals

After the well was put on production, the Flow Scanner multispinner production logging tool was run, and data from it was integrated with maps of reservoir zones to identify the most prolific zones within the Woodford Shale. The Flow Scanner measurements determined that more than 90% of the gas was produced from perforations located in three of the nine mapped zones.
These three highly productive layers were adjacent to one another and within 82 ft [25 m] of each other. Furthermore, interpretations derived from EcoScope and Flow Scanner data showed that perforation clusters placed across higher free gas, lower clay content, and lower calcite volume produced more gas.

**Optimizing future wells**

Lateral measurements are crucial to place wells in the most productive layers within the Woodford Shale. Placing perforation clusters across zones with the most favorable rock properties should result in stronger performance from all the perforation clusters, ultimately increasing the total well production. The operator will apply lessons learned from this well to optimize future operations. This approach of integrating measurements from vertical logging data, lateral LWD data, and production logs is essential to understand how to optimize production from other heterogeneous shale plays.
Newfield Saves 2½ Days on Woodford Shale Well

Case study: Powered rotary steerable system used to drill longest lateral in Oklahoma—10,394-ft—reduces surface torque and drillpipe wear.

**Challenge**

Drill and complete super extended lateral in undulating Woodford Shale within AFE.

**Solution**

Use Schlumberger directional drilling technology—PowerDrive* rotary steerable systems and SlimPulse* third-generation slim MWD tool—to geosteer well to best place in less time.

**Results**

- Reached TD 2½ days ahead of schedule.
- Ran production casing successfully without need to condition hole.
- Final lateral length of 10,394 ft was new record for Newfield and longest in Oklahoma.

**Drill super extended lateral in Woodford Shale**

Gas production wells being drilled in the Woodford Shale play in the state of Oklahoma, USA, typically had horizontal lateral sections about 5,000 ft long. Newfield Exploration Mid-Continent Inc. planned to drill and complete a well with a super extended lateral section twice that length—without exceeding the AFE target days.

**Optimize performance**

The well’s upper, vertical section was drilled to the kickoff point (KOP) using a PowerV® vertical drilling system that automatically maintained verticality and reduced tortuosity. Then the tight curve section was drilled as planned with a positive displacement motor.

In the super extended lateral section, use of a PowerDrive vortex® powered rotary steerable system and SlimPulse MWD tool was more than double the length of a typical lateral.
Case study: Powered rotary steerable system used to drill longest lateral in Oklahoma—10,394-ft—reduces surface torque and drillpipe wear

System (RSS) reduced surface torque and the drillpipe wear that had occurred in prior wells due to sustaining high rpm during long lateral runs.

In addition, the PowerDrive vortex motor's differential pressure gave drillers a better idea of how well the bit was loaded than weight on bit and rotary torque measurements provided. A SlimPulse third-generation slim MWD tool delivered gamma ray measurements for geosteering in the lateral section, and a consistent ROP was maintained from start to finish of the lateral, despite the tortuosity purposely created to meet geological objectives.

The SlimPulse tool was installed between the motor section and steering section of the PowerDrive vortex RSS, which placed the direction and inclination (D&I) package close to the bit for superior directional control. D&I and drilling mechanics measurements—such as stick/slip, collar rpm, and lateral shocks—were transmitted to the surface in real time, enabling the drillers to adjust parameters to optimize both steering and drilling performance.

Reach TD in less time

Schlumberger directional drilling technology helped Newfield reach TD in the Woodford Shale 2½ days ahead of schedule—and delivered a smooth borehole that enabled the production casing to be run successfully without any hole conditioning. The final length of the super extended lateral was 10,394 ft—more than twice the typical lateral length of 5,000 ft. It was a new record for Newfield and the longest lateral ever drilled in the state of Oklahoma.

Contact your local Schlumberger representative to learn more.

www.slb.com/drilling
PDC Mountaineer Improves Production More Than 50% With Optimized Completion Designs

Sonic Scanner tool data and Mangrove methodology help increase reservoir-to-wellbore connectivity in Marcellus shale while reducing time, costs, and risk.

**CHALLENGE**
Improve productivity and operational efficiency in horizontal wells by optimizing the placement of perforation and hydraulic fracturing treatments.

**SOLUTION**
Use Sonic Scanner* acoustic scanning platform and the Mangrove* completion advisor workflow to engineer precise staging and perforating designs.

**RESULTS**
Significantly enhanced stimulation coverage across the length of the laterals, increasing production by more than 50% and eliminating screenouts. PDC Mountaineer (PDCM) now plans to use Sonic Scanner logs in conjunction with the Mangrove platform on all future Marcellus development.

“Schlumberger has provided us with a unique and affordable approach to optimize our recoverable reserves in the Marcellus shale. PDCM will not complete any of our lateral Marcellus wells without first running this service and evaluating the results.”

Dewey Gerdom
CEO, PDC Mountaineer, LLC

PDCM wanted to optimize horizontal well completions and productivity
To complete its Marcellus shale’s horizontal wells simply and cost-effectively, PDC Mountaineer, like most operators, typically uses geometric perforation designs. With this technique, perforation clusters are placed at equidistant points along the lateral. However, microseismic monitoring showed that this type of stage selection often distributed hydraulic fracturing treatments unevenly. The fracture treatments propagated to the lowest-stress zones, leaving the majority of perforations understimulated. PDCM wanted to gain a deeper understanding of the reservoir and improve reserve recovery. PDCM partnered with Schlumberger to identify low-stress intervals, develop more effective completion designs, and ultimately improve well economics.

**Sonic Scanner tool and Mangrove methodology optimized completion designs**
Schlumberger deployed its Sonic Scanner acoustic scanning tool on wireline to map out mechanical rock properties. The tool’s advanced borehole acoustic measurements were loaded into the Petrel* software platform and interpreted using the Mangrove completion advisor workflow. Once processed, the critical well information, including in situ stress, lithology, and Young’s modulus, enabled PDCM and Schlumberger to engineer custom staging and perforating designs. This ensured more consistent stimulation along the entire lateral, and lower breakdown and treating pressures.

“When we’ve used the Schlumberger Sonic Scanner tool to identify and place the staged intervals based on like-rock completion, we have never screened out,” said Jacob Caplan, Senior Completions Engineer, PDC Mountaineer. “We’ve also had a better handle on the breakdown pressures to be expected, further reducing our risk of screening out. The screenout rate was 35% when we didn’t use Sonic Scanner tool, and on average, each screenout costs PDCM USD 300,000.”

Microseismic monitoring clearly shows that the fracture initiates in the lowest-stress interval (in red), and treatments tend to understimulate higher-stress intervals (in pink and blue).
**CASE STUDY:** Sonic Scanner tool data and Mangrove methodology help increase reservoir-to-wellbore connectivity

Production increased more than 50%, leading PDCM to use the Mangrove workflow in all future wells

The Flow Scanner* horizontal and deviated well production logging system showed significantly higher flow rates from wells that used the Sonic Scanner tool and Mangrove methodology than offset wells completed with conventional geometric perforating designs.

“Based on the total number of wells PDCM has producing in the Marcellus, I believe the minimum increase we could expect from utilizing this methodology is 50–60%,” said Caplan.

After the success of the pilot wells, PDCM decided to use this technique to help maximize ROI of all future horizontal wells in the Marcellus shale. The Mangrove workflow has been used in subsequent PDCM wells with similar results. Recently, PDCM used Mangrove software to automatically select intervals, dramatically reducing interpretation time.

Petrel software allows the logs obtained in the lateral to be viewed in a 3D environment. This enables engineers to make better decisions when designing the completion.

Production improvement was directly attributed to the identification and selection of optimal perforation locations based on property logs.

www.slb.com/mangrove

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Industry Partnership Defines Fracture Completion Best Practices in North Dakota Bakken Play

Bakken Research Consortium identifies key controls for economic production from unconventional oil reservoirs

**CHALLENGE**
Unravel geological and geomechanical factors that affect fracture initiation and propagation in the Middle Bakken and Three Forks plays, using best-in-class technologies.

**SOLUTION**
Drilled three parallel laterals; ran high-end logs to characterize reservoirs; compared single-stage fracture completion in one lateral with multistage frac in another.

**RESULTS**
Documented effective multistage completion techniques, which have become common practice since 2008 and boosted oil production and estimated ultimate recoveries.

In 2008, Schlumberger DCS and industry partners studied three horizontal wells in the North Dakota Bakken to identify optimal hydraulic fracture completion techniques.

**Understanding reservoir complexities, completion strategies**
After several years of successful drilling and completion of horizontal wells on the Montana side of the Williston Basin, operators began seriously exploring the North Dakota Bakken play in 2006. Although the Bakken is more extensive in North Dakota, it is also more lithologically heterogeneous.

Initially, the industry did not fully understand reservoir complexities or optimal hydraulic fracture completion strategies. It was common at the time to run a perforated liner and try to fracture-stimulate the entire lateral in one continuous stage. But results were disappointing, production was inconsistent, and North Dakota Bakken development lagged behind that of Montana.

Operators experimented with various drilling and completion technologies and frac fluids, but each new player’s learning curve in this exciting new oil resource proved long, expensive, and redundant. The key challenge was to better understand and control fracture initiation and propagation in the Middle Bakken and Three Forks formations.

**Identifying factors affecting hydraulic fracture stimulation**
In the fall of 2007, the Bakken Research Consortium was formed by Schlumberger Data & Consulting Services (DCS) as the primary technical partner and project leader, with seven operators and three other technical contributors, including the US Department of Energy. The consortium also received a grant from the North Dakota Oil and Gas Research Council.
The objective was to apply best-in-class technologies to improve understanding of the geological, drilling, and completion principles necessary to optimize production. The study area is on the eastern flank of the Nesson anticline in Williams County, North Dakota. A vertical pilot hole and three horizontal wells were drilled 1,500 ft apart in early 2008.

A high-end log suite was run to fully characterize matrix mineralogy, porosity, permeability, mechanical properties, and stress states. The central lateral was cored, and a downhole geophone string was installed to monitor microseismic events caused by hydraulic fracture stimulation of the two outside laterals. One was completed in a single stage with a preperforated liner—the current industry practice. The other was completed with swell packers, a blank liner, and six plug-and-perf frac stages using a hybrid fluid design. Chemical and radioactive tracers were used to tag frac fluids and proppants for each stage.

**Developing industry completion best practices, boosting oil production**

Multidisciplinary analysis, modeling, and simulation found that stress variations within the lateral impact fracture initiation, and fluid type coupled with a clear understanding of rock properties affects fracture height growth. Because of significant variations in reservoir lithology, proper well placement is essential in this play. Most important, the team demonstrated unequivocally that multistage completions provide better fracture stimulation than a single-stage completion.

Consortium members immediately used these findings to optimize their completion strategies. Today, completions with an increasing number of fracture stages are common. According to the North Dakota Department of Minerals, significant increases in estimated ultimate recovery (EUR) and oil production rates over the past few years are primarily a result of the introduction of multistage fracturing in 2008.

One consortium operator, for example, completed its first 12-stage frac job of a short lateral in late 2008. This change increased EUR relative to single-stage completions by more than 284,000 barrels of oil equivalent (boe). By November 2010, the company had drilled 39 consecutive long-lateral Bakken and Three Forks wells in North Dakota, with up to 38 fracture stimulation stages, producing an average of 2,777 boe over the first 24 hours of operation.
Barnett Shale Operations Achieve Remote Real-Time Microseismic Interpretation with Private and Dedicated Wireless Networks

Case study: Expediting field operations and improving collaboration for accurate decision making

Challenge
Optimize remote processing and collaborative interpretation of microseismic data acquired and transmitted from wellsite to office. Access very large seismic datasets in real time and provide mapped microseismic locations for display at both the wellsite and remote sites.

Solution
Use the InterACT* connectivity, collaboration, and information system; StimMAP LIVE* real-time microseismic fracture monitoring, in conjunction with Petrel* seismic-to-simulation software; and IPerformer* Wireless Broadband service, a WiMAX-based terrestrial radio network with 1,700-bps circuitry for high-volume, high-speed, low-latency data transmission.

Results
Improved decision making by instantaneously communicating field operations data to the corporate office. Delivered cost-effective, consistent, and high-quality connectivity (100% uptime and less than a 60-ms delay).

Inefficient microseismic data transmission
In the Barnett Shale, the largest natural gas play in Texas, hydraulic fracture monitoring (HFM) services are often used to map ongoing treatments. Operators needed more efficient office support of critical decisions, so a new method was sought to improve transmission speed of high volumes of microseismic data for real-time processing and interpretation.

Processing data remotely would improve overall efficiency, minimize safety risks, and provide access to high-power computer systems not available in the field. Remote transmission of full seismic data waveforms (not just triggered events) was key to reaching this goal. The main difficulty was that seismic datasets could exceed 5 GB, causing throughput and delay issues that traditional data transmission methods could not always handle. The new method had to provide microseismic event data to decision makers on location or in the office within 30 seconds of detection.
Case study: Expediting field operations and improving collaboration for accurate decision making

**Combination of services for a pilot well**

Schlumberger Data & Consulting Services (DCS) and Schlumberger Information Solutions (SIS) collaborated on HFM requirements. A combination of StimMAP LIVE, Petrel, IPerformer, and InterACT technologies was first applied to a pilot well to test mobilization, setup, and performance.

StimMAP LIVE diagnostic services were run by DCS to monitor microseismic fractures in real time as they were created. Used with SIS Petrel software, this service enabled operators to visualize fracture development and make real-time treatment adjustments to optimize job effectiveness.

Partnered with ERF Wireless, Inc., SIS also delivered a high-capacity broadband service to the Barnett operators. This included IPerformer connectivity—a 1,700-bps, WiMAX-based terrestrial radio circuit positioned alongside the standard VSAT service. Designed for oil and gas business applications, the IPerformer service ensured high performance, reliability, and security for transmitting full waveform data.

The solution also offered low latency, with less than a 60-ms delay, no contention (1,700 bps unshared), and 100% reliability. Both onsite and remote geophysicists could access ongoing jobs in real time through a continuous feed from the field via the Internet and the Schlumberger InterACT Web server, employing secure encryption. Network statistics recorded over a 24-hour period during pilot well testing indicated:

- uptime of 100%
- upload bandwidth speeds of 1,700+ bps
- download bandwidth speeds of 1,700+ bps
- average upload speed of 468 KBps
- average latency of 20 ms or less.

**Collaborative seismic interpretation**

The pilot showed that collaborative seismic interpretation could be accomplished remotely with minimal processing and visualization delay, bringing field operations to operation support center experts in real time. The wireless broadband service enabled the WiMAX network to achieve 100% uptime with negligible packet retransmissions. Wellsite and remote staff indicated that where high data rates are expected, this communication service performs significantly better than using VSAT communications alone. Due to the pilot’s success, this solution will be expanded to other operations within the communications coverage area of Texas and surrounding states.

**Schlumberger Information Solutions**

Schlumberger Information Solutions (SIS) is an operating unit of Schlumberger that provides software, information management, IT, and related services. SIS collaborates closely with oil and gas companies to solve today’s tough reservoir challenges with an open business approach and comprehensive solution deployment. Through our technologies and services, oil and gas companies empower their people to improve business performance by reducing exploration and development risk and optimizing operational efficiencies.

E-mail sisinfo@slb.com or contact your local Schlumberger representative to learn more.
Completions Optimized with Integrated Geomechanical Approach

Integrated geomechanical and petrophysical analysis of core data helps increase production by 500 Mcf/d

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<th>CHALLENGE</th>
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<td>Determine most effective stimulation treatment and avoid previous costly mistakes.</td>
<td>Evaluate formation using TerraTek* rock mechanics and core analysis services.</td>
<td>Achieved better stimulation treatments and more economic completions, with an increase in production of 500 Mcf/d.</td>
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Reservoir evaluation disrupts fractured completion trend
Fracture growth out of the zone, potentially into water zones, had delayed and damaged multiple completion opportunities for an operator in the Barnett Shale. To determine the most effective stimulation treatment for the completion of this complex reservoir, the formation evaluation would need to be multifaceted and include thorough geomechanical and petrophysical properties determination with downhole scanning tools. The evaluation goals were threefold: examine petrophysical data to determine reservoir quality; analyze geomechanical properties of the formation through a detailed core analysis; and combine the petrophysical evaluation, the

Cluster analysis with anisotropic mechanical prediction.
CASE STUDY: Integrated geomechanical approach increases gas production by 500 Mcf/d

comparison between log-derived and core-measured geomechanical properties, fluid-sensitivity tests, and offset well data to make the best recommendation for completion.

Anisotropic stress model delivers fracture success
Schlumberger used TerraTek services to perform an evaluation of this Barnett Shale reservoir. Analysis gave the operator a detailed evaluation of this formation and a completion methodology designed for success. The completion methodology, designed for perforation placement avoiding laminated intervals, focused on more siliceous layers with low-closure stress. To avoid fracturing down into the water zone below the shale, analysis suggested perforating in intervals to promote upward growth.

With the analysis providing a full understanding of the reservoir, the operator incorporated a tapered proppant mesh throughout the course of the hydraulic fracture treatments. Key components of the evaluation methodology included the use of ECS* elemental capture spectroscopy sonde, FMI* fullbore formation microimager, ELANPlus* software, Sonic Scanner* acoustic scanning platform, Platform Express* wireline logging tool, and TerraTek core analysis to provide a complete characterization of the reservoir and its potential.

Processing mechanical properties with an anisotropic stress model is critical to predicting and mitigating proppant entry issues, as well as predicting fracture geometry. A thorough knowledge of the stress gradient and contrasts is vital to determining the optimum way to hydraulically fracture the reservoir. Detailed fluid sensitivity tests lead to the selection of the best fracturing fluids.

Complete analysis leads to solid completions
Combining all of these analyses with a perforation strategy helped the client avoid completion failures common in this reservoir, like fracture growth out of the zone, potentially into a water zone. The 3D anisotropic processing revealed that apparent fracture barriers in carbonate and high-clay intervals did not exist. Surface-passive microseismic monitoring of the hydraulic fracture treatment later confirmed this. The relevance of processing geomechanical data with an anisotropic stress model proved invaluable to the development of the reservoir.

Analysis of core data resulted in better placement for perforation clusters, optimized well trajectory for horizontal laterals, and enhanced production. This well, completed using TerraTek analysis, showed an average production increase of 500 Mcf/d.
StimMORE Service Restores Well Productivity for a Major Barnett Shale Operator

Case study: Integrated approach to well stimulation improves EUR by 20%

Challenge
Refracture existing horizontal wells in the Barnett Shale to improve declining well performance.

Solution
Used StimMORE* service, which incorporates StimMAP* LIVE microseismic monitoring service, to refracture and achieve good zonal coverage without mechanical intervention.

Results
Improved well estimated ultimate recovery (EUR) by 20%.

A vastly unexploited option
Horizontal well completions in the complex Barnett Shale reservoir have increased steadily in recent years, and the standard completion method is placing multiple transverse fracture treatments across the wellbore. A typical first-year average gas production decline is more than 50%, making completions in this reservoir good candidates for restimulation. Finding an economically feasible way to reenter the well and place multiple fractures in the wellbore is another limiting factor in the refracturing treatments that are undertaken today. These limitations make refracturing a vastly unexploited option in this area.

Refracturing improves well productivity and increases ultimate recovery.

To access trapped gas reserves, a major operator in the Barnett Shale collaborated with Schlumberger to develop a technique to refracture a horizontal well in the Barnett Shale. After an initial gas production of approximately 2,200 Mcf/d, well performance declined to less than 500 Mcf/d in 4 years. However, microseismic monitoring of the original stimulation treatments confirmed the opportunity to contact more of the reservoir rock.
Case study: Integrated approach to well stimulation improves EUR by 20%

An integrated approach to refracturing
The operator selected the Schlumberger StimMORE refracturing service for this treatment. The StimMORE service combines a unique fluid-based, tool-free fracture diversion technology with StimMAP LIVE real-time fracture monitoring.

The diversion slurries consisted of a multicomponent blend of degradable materials that temporarily block fractures, diverting fluid flow and inducing the creation of additional fractures in situ and/or at the wellbore. StimMAP LIVE diagnostics were used during the treatment to confirm the lateral section that the stimulation fluids contacted, and four diversion plugs were pumped to maximize lateral coverage.

Cost-effective completion and increased recovery
This new approach to refracturing improved well economics by avoiding costly intervention techniques and optimizing stimulation treatment in real time. Based on the estimated production decline, the operator expects payback for the stimulation treatment within 6 months. More importantly, over a 20-year time period, recoverable reserves are expected to increase by 20%.

About the Contact family
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StimMORE service, which combines fluid-based, tool-free fracture diversion technology with StimMAP LIVE real-time data, enabled efficient and cost-effective completion of the previously unstimulated well sections.

The graphs show stimulation results using conventional treatment methods and the results using the StimMORE service.

Projected recovery comparison over 20 years.
Improve Production With Optimum Fracture Design in Real Time

Case study: StimMAP services provide hydraulic fracture monitoring and interpretation for enhanced stimulation optimization in Barnett Shale reservoir

Challenge
Create optimum fracture design in a complex and unconventional reservoir to optimize recovery.

Solution
Use StimMAP* services to generate a 3D map of microseismic events. Create a model to enable optimization of horizontal completions.

Results
Refined hydraulic fracturing in real time for improved control, operational cost savings, and future design optimization.

Refine fracture design
An increasing number of wells require fracture stimulation to be economically productive. For wells in the complex Barnett Shale region, it is difficult to develop an optimal fracture design. An Oklahoma operator wanted to refine fracture design for greater efficiency in this unconventional gas reservoir, which had previously been bypassed as too difficult to model. Real-time answers were needed to determine the number of stages in the fracture and enable updates at each stage. It was essential to stay within the producing zone, using ball sealers at the right time to move to the next stage and avoiding growth into the water-bearing zone. With real-time answers, stimulation optimization recommendations could be made for the well and for future horizontal completions in the reservoir.

Map View of Microseismic Events Scaled by Stage

Map view of microseismic locations from a four-stage slickwater stimulation treatment.
Case study: StimMAP services provide hydraulic fracture monitoring and interpretation for enhanced stimulation optimization in Barnett Shale reservoir.

StimMAP services, which had proven their value in previous wells, were chosen to create an optimum fracture design using accurate image geometry of the hydraulic fracture.

Make adjustments in real time

StimMAP services, which had proven their value in previous wells, were chosen to create an optimum fracture design using accurate image geometry of the hydraulic fracture. StimMAP hydraulic fracture stimulation diagnostics is the first and only service able to monitor the fracture development in real time or after the event. In the past, operators had relied on pressure gauge readings and temperature changes to determine whether the fracture was complete. Microseismic data for StimMAP services were acquired with the multishuttle VSI® Versatile Seismic Imager and processed on location to generate a 3D computer image of the fracture system, enabling the stimulation treatment of subsequent stages to be reengineered.

From the 3D map of acoustically determined microseismic events (height, length, and width) a model incorporating the fracture parameters was created. Using the model to interpret the fracture geometry and azimuth, changes were made in real time. The ability to observe the growth of the acoustic fracture fairway in real time allowed for modifications on location to the completion design in perforation strategy, treatment volumes, and injection rate to stay out of the water-bearing zone.

Improve efficiency and save costs

Accurate image geometry of the hydraulic fracture in real time refined and improved control. A complete reservoir model was developed and measurement of the production contribution of each stage was used to evaluate the effectiveness of the stimulation treatment. Overlapping fractures were prevented by increasing the distance between zones, fracturing efficiency was improved by using ball sealers, and the water-bearing zone was avoided thanks to real-time decisions. More efficient fractures saved operating costs, improved production, and optimized future horizontal completion designs.

Transverse view of microseismic locations from four-stage slickwater stimulation treatment orthogonal to the preferred fracture orientation.

www.slb.com/stimmap
StimMORE Service Increases EUR in Barnett Shale Well by 0.25 Bcf

Case study: Integrated approach results in daily production increase of nearly threefold

Challenge
Stimulate the nonproducing heel section of a horizontal Barnett Shale gas well.

Solution
Used StimMORE service, which incorporates StimMAP LIVE microseismic monitoring service, to increase stimulation coverage of the lateral and bring the targeted zones to production.

Results
Increased lateral coverage by 25%, resulting in a production increase from 500 Mcf/d to 1,200 Mcf/d. Increased estimated ultimate recovery (EUR) by 0.25 Bcf.

Reservoir stimulation in the Barnett Shale
Horizontal completions in the complex Barnett Shale reservoir have increased steadily over the years. The standard completion method in this area is to place multiple transverse fracture treatments across the wellbore. However, declining gas production continues to be a problem with a typical first-year average production decline of more than 50%. As a result, these wells generally need to be refractured within 5 years of the initial completion. Finding an economically feasible way to reenter the well and place multiple fractures in the wellbore is a limiting factor in the number of refracturing treatments that are done today. These limitations make refracturing a vastly unexploited option in this area.

The initial completion of a horizontal cased hole gas well completed in January 2005 consisted of 4 fracture stages across a total of 16 perforation intervals between 7,396 ft and 9,853 ft. Each fracture stage was separated by a mechanical bridge plug.

The well initially produced approximately 4 MMcf/d of gas, but by January 2006, production had declined by almost half. Microseismic data indicated less than optimal reservoir stimulation during the third and fourth fracture stages of the original treatment. Production logs from May 2006 and September 2007 also indicated that a significant portion of the reservoir in the heel section of the well was not producing.
Case study: Integrated approach results in daily production increase of nearly threefold

After the treatment, production increased immediately from approximately 500 Mcf/d to 1,200 Mcf/d, and payout is expected within 9 months. The treatment is also expected to increase EUR by 0.25 Bcf.

Production performance of Barnett Shale well as a result of StimMORE refracturing treatment.

The client contacted Schlumberger to design a refracturing treatment to stimulate the nonproducing section of the reservoir.

**Efficient refracturing of horizontal wellbores**

StimMORE service, which incorporates StimMAP® LIVE real-time fracture monitoring service, was selected for the treatment. The StimMORE service enables efficient refracturing of horizontal wellbores to improve well productivity and well recovery.

A single-stage treatment, which required no mechanical plugs, was proposed for refracturing the well. StimMORE diversion stages were pumped to allow for movement of the fracture entry point along the lateral. During the treatment, multiple diversion plugs were pumped based on feedback from the StimMAP LIVE monitoring.

**Potential increase in recoverable reserves**

During the refracturing treatment, a large section of the original fracture was restimulated and microseismic data indicated that approximately 25% of new lateral was also stimulated.

More importantly, production after the treatment increased immediately from approximately 500 Mcf/d to 1,200 Mcf/d, and payout is expected within 9 months. Additionally, the treatment is estimated to have the potential to increase recoverable reserves by 0.25 Bcf.

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HiWAY Technique Increases Condensate Production by 43% in the Eagle Ford Shale

Channel fracturing delivers step-change in well performance while reducing water consumption by 58%

## CHALLENGE
Improve oil and gas production and operational efficiency in the competitive Eagle Ford shale.

## SOLUTION
Apply HiWAY* flow-channel hydraulic fracturing technique in horizontal completions to increase the effective stimulated rock volume by creating stable, infinitely conductive channels within the proppant pack.

## RESULTS
The HiWAY fracturing technique increased 60-day cumulative oil production by 43% and 60-day cumulative gas production by 61% while reducing water and proppant consumption per well by 58% and 35%, respectively.

## Challenging conditions
Working in the Eagleville field in South Texas, a large Gulf Coast operator continually aims to improve production from the Eagle Ford shale. The formation mainly comprises limestones and shales with:
- 7 to 10% porosity
- 200 to 600 nD
- 8,000- to 10,000-psi reservoir pressure
- 4.1 to 8.4 Mpsi Young’s modulus.

Production from this area is driven by the effective stimulated rock volume (ESRV) and the reservoir connectivity with the wellbore that can be established via hydraulic fracturing. High fracturing gradients (typically 0.92 – 1.00 psi/ft) and bottomhole static temperatures (280 – 310 degF) at depths between 11,800 and 12,200 ft are challenging conditions for successful execution of fracturing treatments.

Logistics are also challenging for these operations. This section of the Eagle Ford Shale has generally been stimulated using multistage horizontal completions with high-rate slick-water treatments. Such treatments require millions of gallons of water and millions of pounds of proppant per well. The ongoing expansion of fracturing activity in the Eagle Ford shale further constrains the limited availability of water and proppant in the area. The need exists to increase operational efficiency by reducing the amount of materials used in these operations.

The HiWAY flow-channel fracturing technique was applied to address these challenges and improve well performance beyond conventional means.

## Planning the evaluation campaign
This operator chose to evaluate the HiWAY flow-channel hydraulic fracturing technique from Schlumberger for the stimulation of wells in the Eagleville field in a four-well study. Two wells were stimulated with the HiWAY technique. The other two wells were stimulated simultaneously with the conventional method.

The landing of the wells was carefully planned to provide the best possible basis for comparison. The wells treated with the HiWAY technique had been drilled from a single pad, in opposite directions. The other two wells had also been drilled in opposite directions from a single pad located just 3,500 ft away and parallel to the first two wells. The average lateral length for each pair of wells differed by only 1%.

Rather than leaving fracture flow dependent on proppant pack conductivity, the HiWAY fracturing technique creates stable channels for oil and gas to flow through. These stable channels offer limitless conductivity, thus increasing flowback and reducing pressure drop across the fracture. These effects lead to greater ESRV and consequently, higher oil and gas production.
CASE STUDY: Channel fracturing delivers step-change in well performance while reducing water consumption by 58%

<table>
<thead>
<tr>
<th>Fracturing technique</th>
<th>Lateral length, ft</th>
<th>Fracturing fluid, bbl</th>
<th>Proppant, lbm</th>
<th>Cumulative condensate, bc</th>
<th>Cumulative gas, MMcf</th>
<th>Wellhead flowing pressure, psi</th>
<th>Water recovery</th>
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</thead>
<tbody>
<tr>
<td>HiWAY (2 wells)</td>
<td>4,405</td>
<td>87,500</td>
<td>2,395</td>
<td>26,535</td>
<td>30.1</td>
<td>2,156</td>
<td>13.0%</td>
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<tr>
<td>Conventional (2 wells)</td>
<td>4,368</td>
<td>207,103</td>
<td>3,709</td>
<td>18,555</td>
<td>18.7</td>
<td>1,916</td>
<td>10.9%</td>
</tr>
<tr>
<td>Difference</td>
<td>1%</td>
<td>-58%</td>
<td>-35%</td>
<td>43%</td>
<td>61%</td>
<td>13%</td>
<td>19%</td>
</tr>
</tbody>
</table>

More production with fewer resources
During the first 60 days after stimulation, the wells treated with the HiWAY technique produced an average of 26,535 barrels of condensate (bc) with 30.1 MMcf of associated gas. The wells treated conventionally produced an average of 18,555 bc with 18.7 MMcf of associated gas. Furthermore, the average wellhead flowing pressure for the wells treated with HiWAY channel fracturing was 2,156 psi versus 1,916 psi for the conventional wells. Therefore, the HiWAY technique increased condensate and gas production by 43% and 61% respectively while delivering higher flowing pressures.

Very importantly, these results were obtained while reducing the amount of water and proppant used per well by 58% and 35%, respectively. The operator saved more than 10,000,000 gal of water and 2,600,000 lbm of proppant in the two wells stimulated with HiWAY channel fracturing. The reduction in the amount of materials required to stimulate a well simplifies logistics, reduces completion costs and minimizes safety and environmental risks.

By virtue of these results, the energy company has requested the use of the HiWAY technology on future wells within its lease.
Channel Fracturing Increases Production by 37% for Petrohawk in the Eagle Ford Shale

HiWAY technology improves fracturing performance and EUR for horizontal wells in South Texas

CHALLENGE
Improve oil and gas production in the Eagle Ford Shale.

SOLUTION
Apply HiWAY™ flow-channel hydraulic fracturing technique in horizontal completions to increase the effective stimulated reservoir volume by creating stable channels and limitless fracture conductivity.

RESULTS
Increased initial gas production by 37% and initial oil production by 32%. Petrohawk announced increase in estimated ultimate recovery (EUR) for the field and converted all Schlumberger fracturing activity to the HiWAY technique.

“Petrohawk has converted 100% of frac services provided by Schlumberger in the Eagle Ford to HiWAY. Currently, Petrohawk is utilizing all available capacity of this technology.”

Petrohawk press release

Challenging conditions
Working in the Hawkville field near Cotulla, Texas, Petrohawk aims at improving production and EUR from the Eagle Ford Shale. The formation mainly comprises limestones and shales with
- 6% to 10% porosity
- 200 to 600 nD
- 7,000-10,000 psi bottomhole pressure
- 2.0 to 4.5 Mpsi Young’s modulus.

Production from this area is driven by the effective stimulated reservoir volume (SRV) and the reservoir connectivity with the wellbore that can be established via hydraulic fracturing. The field has high fracturing gradients (typically 0.91-1.00 psi/ft) and high bottomhole temperatures (270-300 degF) at depths between 10,000 and 13,000 ft. These are challenging conditions for the successful execution of fracturing treatments.

Since its discovery in 2008, this section of the Eagle Ford formation has generally been stimulated using multistage horizontal completions with high-rate slickwater treatments. However, recently there has been a trend to use polymer-based crosslinked and hybrid treatments. This evolution has led to a moderate improvement in production results.

CASE STUDY

Channel Fracturing Increases Production by 37% for Petrohawk in the Eagle Ford Shale

HiWAY technology improves fracturing performance and EUR for horizontal wells in South Texas

Stimulation
Flow-channel creation for two wells
Petrohawk chose to implement Schlumberger HiWAY flow-channel hydraulic fracturing technique to address these challenges and improve well performance for the stimulation of wells in the Hawkville field.

Two wells were selected to build an initial assessment: Heim #2H well, located in a gas-producing window of the field, and Dilworth #1H well, located in a condensate-producing window of the field. Results were compared with those from valid offsets previously stimulated by using conventional techniques.

Rather than leaving fracture flow dependent on proppant pack conductivity, the HiWAY fracturing technique created stable channels for hydrocarbons to flow through, thus increasing the effective stimulated reservoir volume.

Outstanding production results
The enhanced stimulation of the reservoir provided by HiWAY channel fracturing gave the Heim #2H well a maximum initial rate of 14.5 Mcf/d, or 37% higher initial gas production than the best comparable offset well. The HiWAY technique gave the Dilworth #1H well a maximum initial rate of 820 bbl/d, or 32% higher initial oil production rate than the best comparable offset. Production rates and wellhead pressures for these two wells remain the highest among all wells in their corresponding areas.

In a recent press release, the results of the HiWAY technique were mentioned by Petrohawk: “In Hawkville Field, a new frac design has significantly improved the Company’s EUR estimates. … Two wells with sufficient production history to estimate EUR’s are the Heim #2H, which is projected to produce an estimated 8.9 Bcf and 260 Mmbgl, and the Dilworth #1H, which is projected to produce an estimated 2.1 Bcf and 400 Mmcf and 208 Mmbgl.”

Based on these results, Petrohawk has increased its utilization of Schlumberger HiWAY technology and has requested the deployment of an additional fracturing fleet in the Hawkville field. More than 900 HiWAY treatments have been performed for Petrohawk in over 50 wells to date.
Optimizing Stimulation and Reservoir Characterization Using LWD Measurements in the Eagle Ford Shale

An independent operating company gains in-depth understanding of the Eagle Ford Shale to optimize its stimulation program

CHALLENGE
Well placement, reservoir characterization, completion design, and stimulation optimization of a horizontal well in the Eagle Ford Shale.

SOLUTION
EcoScope* and sonicVISION* measurements to steer the lateral in real time, perform structural interpretation using azimuthal borehole images, and derive reservoir and geomechanical properties to optimize completion design and enhance stimulation treatment.

RESULTS
Real-time acquisition, interpretation, and integration of well measurements, which helped the operator to prevent unexpected drilling events, evaluate the reservoir, and optimize the stimulation operation.

EcoScope and sonicVISION data revealed dip changes in Eagle Ford layers. The borehole image enabled the identification of a fault near the toe of the lateral.

The benefits of LWD data
An independent operator drilling a new well in Webb County, Texas, planned to extend the horizontal section to an area beyond 3D seismic coverage and to log the entire lateral while drilling. LWD measurements were transmitted in real time to help ensure optimal placement of the lateral within the geologic structure and to evaluate the reservoir. Schlumberger provided the resources to acquire, interpret, and integrate logging-while-drilling measurements to influence the stimulation program in real time.

Interpreting LWD measurements for Eagle Ford characterization
To perform shale gas reservoir characterization along the lateral, the operator used combinations of the EcoScope multifunction logging-while-drilling service (including density images and spectroscopy), the TeleScope* high-speed telemetry-while-drilling service, and the sonicVISION sonic-while-drilling tool.
With the InterACT* connectivity, collaboration, and information system, real-time data was transmitted from the rig site to Schlumberger OSC* interactive drilling operations and Data & Consulting Services (DCS) scientists and engineers. This remote transmission allowed the operating company personnel to interpret LWD data and monitor drilling mechanics data in real time.

The final interpretation enhanced mineralogy description, structural mapping, and understanding of reservoir and geomechanical properties for integrated shale gas characterization.

**Integrated shale gas characterization for stimulation practice**

Based on this robust evaluation suite, Schlumberger was able to recommend an optimized completion design by placing the perforation clusters guided by reservoir and geomechanical properties. Furthermore, the stress profile and mineralogy from the evaluation were used to optimize the fracturing strategy.

Close coordination of this integrated workflow of data gathering, processing, and analysis helped in providing final recommendations in time for implementation and execution.
Evaluate Fracture Design and Well Placement

Case study: StimMAP diagnostics reveal actual Fayetteville shale fracture geometry

Challenge
Understand complex fracture propagation in the Fayetteville shale and use the data to refine and improve future stage and perforation cluster placement.

Solution
The StimMAP* hydraulic fracture diagnostics service, which maps hydraulic fracture systems in 3D as they are created.

Results
Acquired a better understanding of reservoir response to fracturing, permitting continuous improvement in future fracturing design and overall reservoir management.

Analyze reservoir fracturing
An operator working in the Fayetteville shale needed to better understand the fracturing of the reservoir to optimize production. The operator determined that fracture monitoring could optimize fracturing operations.

Apply innovative solution
The operator selected the StimMAP hydraulic fracture stimulation diagnostics service. In an era of demand for technical resources, the Schlumberger integrated solution offers industry-leading experience and expertise. StimMAP diagnostics map hydraulic fracture systems in 3D as they are created. These measurements can be used to ensure optimal hydraulic fracture placement and improve reservoir development. Information collected is processed on site to refine the fracturing design for the next stage. The service can also be used to evaluate the influence of treatment communication with offset wells.

Map view of microseismic events from a three-stage slickwater ClearFRAC* LT low-temperature polymer-free stimulation treatment.
Case study: StimMAP diagnostics reveal actual Fayetteville shale fracture geometry

StimMAP results enabled better understanding of reservoir response for continuous improvement in fracturing and overall reservoir management. The operator was entirely satisfied with the StimMAP service and now uses it for more than 20% of all wells in the field.

Refine treatment design

StimMAP diagnostics determined that the fracture system was relatively contained within the Fayetteville shale formation. Primary characteristic geometry reflected a complex fracture fairway in all stages and a wider fracture fairway coverage. Overlapping was observed between Stages 2 and 3, and communication was observed in offset wells.

Schlumberger made a number of recommendations for future operations, including evaluation of infill well placement to prevent overlap and possible inefficient drainage; evaluation of the production contribution of each stage to provide confirmation of the treatment design; and the construction of a reservoir model to determine the effective fracture length and drainage area.

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StimMORE Service Restores Well Productivity for a Major Barnett Shale Operator

Case study: Integrated approach to well stimulation improves EUR by 20%

Challenge
Refracture existing horizontal wells in the Barnett Shale to improve declining well performance.

Solution
Used StimMORE* service, which incorporates StimMAP* LIVE microseismic monitoring service, to refracture and achieve good zonal coverage without mechanical intervention.

Results
Improved well estimated ultimate recovery (EUR) by 20%.

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Projected recovery comparison over 20 years.

www.slb.com/reservoircontact
StimMORE Service Increases EUR in Barnett Shale Well by 0.25 Bcf

Case study: Integrated approach results in daily production increase of nearly threefold

Challenge
Stimulate the nonproducing heel section of a horizontal Barnett Shale gas well.

Solution
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Reservoir stimulation in the Barnett Shale
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Efficient refracturing of horizontal wells

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Potential increase in recoverable reserves

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Unconventional Resources

Unmatched expertise in shale reservoirs

Schlumberger integrated technology offerings and expertise, yield improved operational efficiency, enhanced production, reduced risk, predictable results and greater economic success.

EVALUATION—More knowledge, less uncertainty
Proper evaluation of reservoir quality and completion quality are both essential. Selective acquisition and analysis of data leads to less uncertainty and more informed decisions.

DRILLING—More pay zone, less rig time
Drill higher quality, longer laterals, faster, and with greater accuracy. Place wells in the most productive zones for greater economic success. Optimize every aspect of your drilling program.

COMPLETIONS—More reservoir contact, less environmental impact
Identify the most effective completion strategy to maximize reservoir contact and reduce environmental impact.

PRODUCTION MANAGEMENT—More recovery, less footprint
Address water management challenges from provisioning and recycling to treatment and disposal. Diagnose problems and optimize the lifetime production of your wells—maximizing ultimate recovery with fewer wells and fewer interventions.