From Reservoir Specifics to Stimulation Solutions

Comprehensive data acquisition, interpretation and modeling provide a thorough understanding of basins and fields, a prerequisite for successful well completions.

With more complete information, teams of experts develop, refine and apply improved models to design perforation, completion and development strategies that enhance productivity.

Between two and three billion dollars US are spent annually to fracture more than 20,000 wells worldwide. However, less than 1% of fracturing treatments are optimally designed to maximize production and recovery. In spite of increasing demand for stimulation services, the Gas Technology Institute, formerly Gas Research Institute, Chicago, Illinois, USA, reports that two-thirds of hydraulically fractured wells in the United States do not respond as expected and fail to meet operator objectives. The same is true in other parts of the world. One reason cited for this poor performance is lack of an optimization process. Operators, therefore, are continually striving to improve stimulation practices.

In the early 1980s, it seemed as though every well needed a hydraulic fracturing treatment; reputations and résumés were built based on pounds of proppant pumped—many “records” were set. Later, the industry found that, as with most things, there was a point of diminishing returns, and optimization became a key word.

During the past two decades, there has been some optimization of well stimulations, but not nearly enough. Even today, the tendency is to rely on fracturing treatments that have always been performed the same way in a particular area. This means that stimulation design utilizing comprehensive data and detailed designs are not yet common practice.

In addition to enhancing oil production from marginal reservoirs, well stimulation is becoming increasingly important because of growing interest in natural gas, which often is found in lower permeability zones. Formations with low to moderate permeability may require hydraulic fracturing to produce at economic rates. Even for reservoirs with higher permeabilities, stimulation is an effective way to improve production or accelerate recovery, especially during periods of rising oil and gas prices or when project economics require a quick return on investment. Stimulation technology is also applied as a preventive measure to avoid or delay productivity-related problems like sand production, movement of formation fines, scale deposition and organic deposits.

These applications are especially important offshore where remedial well-intervention costs over the productive life of a well or reservoir can be extremely high, often prohibitive. In many cases, stimulation is one of the main costs of completing a well. Advances in three-dimensional (3D) simulation make reservoir characterization and stimulation design more efficient, but acquiring input for these models continues to challenge geologists, petrophysicists and engineers who design drilling, completion or stimulation programs. A vast amount of data and many variables must be considered, some of which are critical for predicting potential production rates, reserves and recovery factors that are used to determine well-completion or stimulation strategies.

The accuracy of petrophysical models and a few key reservoir characteristics, such as permeability, porosity, fluid saturation, magnitude and direction of tectonic stresses, and other rock mechanical properties, dramatically impact field development decisions. Many of these parameters, even those with significant influence on completion and stimulation designs, are all too often based on standard correlations, averages, estimates or even assumptions. Rather than rely on limited data sets, rock catalogs, prior experience and local practices, which may lead to inaccuracies, miscalculations and completion inefficiencies, optimized stimulation designs require the most complete and reliable data possible.

Advanced formation evaluation tools allow in-situ analysis and provide high-resolution, continuous data acquisition across zones of interest to quantify important reservoir parameters and...
improve predictive modeling. These direct measurements and knowledge from other sources, such as core, pressure and production data, and in-situ tests like DataFRAC minifracture treatments, provide correlations to complement and verify empirically derived values. Improved interpretation techniques and innovative formats for processing data are paving the way for better models and simulations by supplying values that were previously unknown or difficult to determine accurately, especially for low-permeability and heterogeneous reservoirs. In some cases, this type of detailed data even helps identify productive zones that might otherwise be overlooked.

To select and apply the best stimulation technologies and completion solutions, both operating and service companies must use a full range of skills and expertise. Collaboration is essential because operators bring reservoir knowledge and field experience, and integrated service providers supply the latest fit-for-purpose technology and expertise derived from work in a variety of fields and basins. In addition to improved stimulation results and enhanced well performance, producers desire cost-effective services delivered in a timely fashion. For this reason, established data-processing services and a knowledge-management infrastructure are indispensable for real-time data exchange between widely dispersed office and field locations.

Comprehensive data acquisition coupled with Web-based information technology improves reservoir characterization to aid in stimulation optimization. With proper knowledge management, experiences and lessons from previous well completions are readily accessible. Information is distributed efficiently so multidisciplinary teams are able to work together even at great distances, which means quicker turnaround times for reservoir characterization. As a result, advances in formation evaluation and fracturing technology developed over the past 20 years can be applied faster and more effectively than ever before, often at reduced cost.

Stimulation optimization takes many forms, from slight modification of fracturing designs to application of new techniques or complete overhaul of field-development schemes. In Egypt, for example, development costs were reduced 42% in one field by changing from a 23-well infill-drilling program to 13 hydraulically fractured wells. The potential exists to greatly improve completion designs, optimize stimulation treatments and enhance production. Hydraulic fracturing of more permeable formations, a proven technique in Venezuela and Prudhoe Bay, Alaska, USA, remains untried in other parts of the world. Refracturing to optimize recovery is another stimulation application that is the subject of ongoing research.

This article focuses on stimulation optimization using the PowerSTIM stimulation and completion process to develop field- or basin-specific models and apply customized well-completion solutions. A proven engineering methodology and unique Web-base workflow are the essence of this initiative. Case histories illustrate how this approach capitalizes on stimulation opportunities and improves financial results by fully utilizing data captured while drilling, evaluating, completing and producing wells.

1. During hydraulic fracturing treatments, fluid is injected at pressures above formation breakdown stresses to create a crack, extending in opposite directions from a well. These fracture wings—half-length—propagate in a preferred fracture plane (PFP) perpendicular to the least rock stress. Held open by a proppant, these conductive pathways increase effective well radius, allowing linear flow into the fracture and to the wellbore. Naturally occurring or resin-coated sand and high-strength bauxite or ceramic synthetics, sized by screening according to standard U.S. mesh sieves, are used as proppants to maintain fracture conductivity.


Finding the Right Solutions

Optimized stimulations require a step change in delivery of formation evaluation, reservoir characterization, and stimulation and completion services. The PowerSTIM initiative provides a workflow and tools for reengineering well completions and stimulation treatments. It combines openhole and cased-hole reservoir characterization, drilling and measurements, completion and stimulation technologies to provide a fresh look at reservoirs. This methodology focuses on well production and field development, integrating petrophysical expertise and reservoir knowledge with design, execution and evaluation.

The PowerSTIM approach focuses on building field- or basin-specific predictive models to deliver timely, customized completion recommendations. This approach helps teams of experts gather, process and evaluate as much information as possible about a reservoir to optimize stimulation and completion designs. Experience and lessons learned are evaluated and incorporated to close the optimization loop.

A thorough process internal to Schlumberger and unique Web-based intranet tool combine answers provided by wireline log data, well tests, core analysis and in-situ testing with stimulation designs to maximize their benefits. PowerSTIM methods generate more value than applying services and processing results separately. Taken together, improved assessment of permeability, porosity, water saturation, mechanical rock properties, stress profiles and net pay form the basis of specific solutions for a particular reservoir or field development.

The PowerSTIM workflow can be divided into two stages. The first stage concentrates on a few wells—three to five—in a field [next page, top]. Through improved data acquisition, detailed analysis and by working closely with the operating company, operator and Schlumberger experts develop a reservoir model that accurately predicts key parameters and forecasts production. Once an initial model is established, emphasis shifts to identifying technologies for improving well performance. Geologists, petrophysicists and reservoir or production engineers use this local model to make completion and stimulation recommendations for various stages in a field’s productive life.

In the second stage, geoscientists and engineers refine the reservoir model and completion designs to quickly deliver integrated stimulation solutions for future wells [next page, bottom]. In many cases, project teams deliver updated models within hours of logging operations. This “in-time” approach makes the PowerSTIM methodology an integral part of completion planning rather than an afterthought. Knowledge gained from acquiring, interpreting and formatting comprehensive data sets using the latest logs, cores and in-situ tests, and state-of-the-art stimulation technology is key to the success of these projects.

One such technology is nuclear magnetic resonance (NMR). Logging platforms such as the CMR Combinable Magnetic Resonance tool excite hydrogen atoms in formations by setting up a magnetic moment, relaxing it and measuring the time it takes atoms to realign. This NMR relaxation time, $T_2$, is dependent on pore size and porosity, which is related to permeability. The $T_2$ distribution is used as an indication of porosity and permeability. Smaller pores have shorter relaxation times; larger pores have longer relaxation times. Laboratory analysis of core samples has identified a useful relaxation time for free versus bound fluids. For typical sand-shale sequences, this cutoff is 33 msec. Pores with relaxation time beyond this cutoff contain producible fluids.

Sonic tools like the DSI Dipole Shear Sonic Imager sonde excite formations with acoustic waves and measure resulting compressional and...
shear transit times. Transittimes are converted into rock properties such as shear modulus, Young’s modulus and Poisson’s ratio. These inferred parameters could be further improved by correlation with direct measurements from core and in-situ formation tests. Radial, or azimuthal, sonic data also can be measured to derive pre-
ferred fracture plane (PPF) direction. These data are useful for ensuring reservoir drainage through proper well placement. The FMI Fullbore Formation MicroImager microresistivity tool is used to identify faults, natural fractures, sec-
ondary porosity and borehole breakout. If present and evident on FMI logs, borehole breakouts occur perpendicular to the principal stress direc-
tion and help confirm DSI data.

These advanced sonic and NMR logging tech-
nologies combined with core analysis, or in-situ
formation tests and well production testing pro-
vide more accurate reservoir characterization for
better fracture simulation and design. Design
programs like the 3D FracCADE model predict
hydraulically induced fracture geometry (height,
length and width) using formation parameters
such as shear modulus, Young’s modulus,
Poisson’s ratio, permeability, overburden stress
and pressure. Several new tools have been
developed to help link formation evaluation, and
petrophysical and production analysis to stimula-
tion and completion design.

For example, the ZoneAID program is a unique
zone-by-zone layering routine to identify and eval-
uate individual zones in a layered formation. This
analysis tool is a critical link between formation
evaluation data and the FracCADE program. The
FracVIZ program is a visualization tool to better
understand fracture geometry, fracture orientation
and fracture barriers as well as their relationship
to reservoir size. Production-data analysis using
the Production Data Fracture Interpretation Tool
(PROFIT) program determines fracture half-length
and conductivity, and effective permeability of
stimulated formations without shutting wells in
for analysis.

The PSPLITR program uses production log
data to correctly allocate production to each
completed interval and ensure quantitative anal-
ysis to reliably estimate production and evaluate
fracture characteristics in commingled, multi-
stage reservoirs. Well productivity is evaluated by
NODAL analysis, a technique that considers perforations, tubulars and surface facilities by
treating each pressure interface as a node with
several variables. These tools and techniques
come together within the PowerSTIM environ-
ment to generate innovative solutions.

Reservoir characterization, the first stage of the
PowerSTIM process.

Optimizing stimulation and completion solutions, the second stage of the PowerSTIM process.


Winter 2000/2001
Predicting Permeability

Permeability impacts completion decisions and dictates optimal fracture designs. High-permeability formations may not need stimulation for enhanced productivity while low-permeability—tight—zones may require massive hydraulic fracturing treatments (right). It is also important, however, to remember that stimulation of high-permeability formations is still a viable option when sand production and formation fines movements are concerns.

Traditional methods of measuring or calculating permeability do not always yield representative values and may be costly, time-consuming or risky. Core samples provide valuable information to fill in gaps, but sample a statistically small portion of the zone of interest. Pressure-buildup tests and production-history matching supply average permeability for perforated zones, but no information about adjacent formations or shales. In some cases, pay intervals may even have to be stimulated first just to flow and test.

To improve Lobo formation completions in South Texas, USA, Conoco looked to other methods of acquiring reliable permeability data. Accurate permeability measurements from individual layers in sections with multiple pay zones are critical for predicting fracture geometry, selecting treatment systems (proppants and fluids) and determining job execution parameters (pumping rates and pressures). Previously, the Lobo asset group obtained permeability values from sidewall core and pressure-buildup data, relying on standard log data and permeability correlations.

Several companies offer permeability logging services, so one option was to develop a method for estimating permeability from continuous wireline measurements. To assess this option, CMR logs were run in wells where permeability data were also acquired by rotary sidewall cores. This project provided essential elements for an integrated team of geoscientists and engineers to address stimulation optimization for a reservoir with variable permeability by applying the PowerSTIM process.

Permeability, stress profile and net pay are key reservoir parameters. The objectives of this evaluation were to calibrate log- and core-permeability data so a reliable local model could be built to predict permeability, quantify reservoir stress profiles and identify net pay, especially potential low-productivity zones. The model needed to be valid across the Lobo trend and available for real-time delivery. The final logging program had to be more cost-effective than other methods of acquiring permeability data.

The initial evaluation consisted of three wells. The logging program for the first well included AIT Array Induction Imager Tool measurements, Litho-Density log, CNL Compensated Neutron Log data and a gamma ray log for correlation. Additional logs were recommended to provide permeability measurements, identify net pay and construct stress profiles for input to the FracCADE design program.

The CMR tool was used to determine pore-size distribution and relationship to permeability. The ECS Elemental Capture Spectroscopy tool provided clay typing and additional petrophysical analysis. Rotary cores taken with a Mechanical Sidewall Core Tool (MSCT) system provided control for calibrating CMR measurements. To be more representative of in-situ conditions, core permeabilities were corrected for net overburden pressure.

The PowerSTIM team relied on ELAN Elemental Log Analysis output and DSI data to obtain mechanical rock properties and stress profiles. To ensure good wellbore-to-formation communication, wells were perforated with deep-penetrating PowerJet charges. Bottomhole pressures were obtained while perforating. The best available methods were evaluated to match CMR permeability with core data.

Initially, permeability was computed using a standard Timur-Coates permeability equation with 33-msec cutoff for $T_2$ in sandstone, and equation exponents based on experience in South Texas. In gas zones, however, CMR porosity can be pessimistic. Both CMR permeability predictions and conventional permeability-porosity relationships showed mixed results when compared with core values (next page, top). The Lobo project team recommended more core points to provide a better permeability baseline for correlation, but borehole conditions prevented adequate data from being obtained in the second well.

Additional rotary cores obtained in a third well allowed testing and refinement of several permeability models. The initial Timur-Coates equation did not work adequately in this well either. Correlation between CMR-derived permeabilities and core values was better in the lower zone than in the top and middle zones (next page, bottom). After correction for net overburden, correlations using a Timur-Coates equation modified for low-permeability reservoirs were encouraging, but still not acceptable.


> Initial log permeability versus Lobo formation sidewall core values. In track Three, permeabilities calculated from CMR Combinable Magnetic Resonance log data using a standard Timur-Coates equation with typical experience-based South Texas exponents and a 33-msec cutoff for $T_2$ (dashed purple curve) did not agree with sidewall core permeabilities (purple dots) in the first well of the Lobo reservoir characterization study. The correlation was acceptable in some zones, but not in others.

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<thead>
<tr>
<th>Porosity</th>
<th>Free fluid</th>
<th>CMR permeability, mD</th>
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<tbody>
<tr>
<td>Neutron porosity</td>
<td>0.3 vol/vol 0.0</td>
<td>Sidewall-cores corrected for net overburden</td>
</tr>
<tr>
<td>Density porosity</td>
<td>0.3 vol/vol 0.0</td>
<td>Net-overburden corrected 0.002 Timur-Coates equation 20.0</td>
</tr>
<tr>
<td>Total CMR porosity</td>
<td>0.3 vol/vol 0.0</td>
<td>Low-permeability 0.002 Timur-Coates equation 20.0</td>
</tr>
<tr>
<td>Crossover</td>
<td>0.3 vol/vol 0.0</td>
<td>Standard 0.002 Timur-Coates equation 20.0</td>
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< Refining log permeability versus Lobo formation sidewall core values. More rotary sidewall cores were obtained in the third well of this study to test and refine the permeability model (purple dots). The standard Timur-Coates equation did not work in this well either (dashed purple curve). Correcting CMR permeabilities for net overburden improved the CMR permeability prediction in the lower zone, but not in the other two zones (green curve). A version of the Timur-Coates equation for low-permeability reservoirs matched core permeability values in the top and middle lobes, but underestimated the lowest zone (black curve).
These new data were used to tailor the Timur-Coates equation specifically for the Lobo formation. A modified CMR-permeability equation was developed using a Timur-Coates equation with exponents provided by Schlumberger-Doll Research, Ridgefield, Connecticut, USA. Effective porosity from the ELAN output was used instead of gas-corrected CMR density porosity because it was corrected for gas, shale and invasion. Using a 90-msec cutoff for T2 to take advantage of oil-base mud invasion characteristics in the Lobo formation refined the ratio of free-fluid volume (FFV) to bound-fluid volume (BFV). Permeabilities calculated using this revised equation show acceptable agreement with core values throughout the well (above).

Conoco was concerned that, depending on lithology, the CMR tool would require ongoing calibration to provide accurate reservoir permeabilities. Laboratory measurements of T2, permeability and porosity were made on cores from several Lobo fields to determine if this was the case. To provide further validation, CMR data from the first well were reprocessed using the modified permeability expression (below). Positive results gave Conoco confidence to remove sidewall cores from the logging program in the study area.

Net-pay calculations were also improved (next page). Standard QLA well-log analysis using three criteria—porosity greater than 12%, water saturation less than 70% and shale volume less than 50%—identified 42 ft [13 m] of pay. An ELAN gas-resource profile using the same criteria identified 50% more pay, or 65 ft [20 m]. The increase was a result of computing different porosities and shale volumes based on additional ECS and CMR data.

Other wells have been logged and completed using CMR permeability as input. Following reservoir characterization, Conoco and Schlumberger used more accurate and consistent permeability, fluid saturation, net pay and stress predictions from the Lobo-specific model to design optimized fracture stimulations that reduced well completion costs and significantly increased gas production.

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<tr>
<td>Crossover</td>
<td>CMR free fluid</td>
<td>0.3 vol/vol</td>
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Validating optimized log permeability versus Lobo formation sidewall core values. In Track 3, log data from the first well in this project were reprocessed using the Lobo-specific equation to validate the permeability model (red curve). Except for one core point near the bottom of the log section, the new expression provided a much better match between sidewall core and CMR permeabilities (purple dots).
Comparison of net pay analyses. Standard QLA well-log analysis using standard criteria of porosity greater than 12%, water saturation less than 70% and shale volume less than 50% identified 42 ft [13 m] of pay (top). With the same criteria, an ELAN gas-resource profile computed 50% more pay, or 65 ft [20 m], but with shale volumes obtained from the ECS Elemental Capture Spectroscopy tool for geochemical logging (bottom).

### Net pay equals 42 ft using ELAN model with CMR and ECS data

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<th>0.5</th>
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<tr>
<td>Gamma ray</td>
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<td>API</td>
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<tr>
<td>Neutron porosity</td>
<td>Density porosity</td>
<td>10</td>
<td>mD</td>
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<tr>
<td>Permeability</td>
<td>Effective porosity</td>
<td>0.2</td>
<td>p.u.</td>
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<td>Volume</td>
<td>%</td>
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Comparison of net pay analyses. Standard QLA well-log analysis using standard criteria of porosity greater than 12%, water saturation less than 70% and shale volume less than 50% identified 42 ft [13 m] of pay (top). With the same criteria, an ELAN gas-resource profile computed 50% more pay, or 65 ft [20 m], but with shale volumes obtained from the ECS Elemental Capture Spectroscopy tool for geochemical logging (bottom).
Interactive Reservoir Characterization

The PowerSTIM approach applies the best available resources to understand wells, fields and basins, and presents tailored recommendations in a technically sound, easily understood format. A comprehensive log, or data montage, is built to communicate formation evaluation, well analysis, reservoir characterization and completion or stimulation designs along with predictions, results and post-treatment evaluations.

This tangible hard copy embodies the value inherent in an intangible methodology.

For the operator, this life-of-the-well montage is an invaluable reference for quick access to well information. The PowerSTIM montage contains detailed reservoir characterization and completion information in a continuous mode. The cover shows well location and relevant background data. Inside, a section of mud log or open-hole log, core analysis and other test data identifies pertinent zones. A wellbore configuration shows the completion design and perforation record. Additional sections present stimulation designs, productivity analyses, production logs and actual production data. As a project progresses, the PowerSTIM team updates the montage, which can be used later to assess future well completions.

A Web-based intranet tool provides a framework for collaboration among various technical disciplines as well as between the operator, Schlumberger and third parties. Beginning with an entire montage presentation, team members can zoom in on any area of the montage for a more detailed view (next page, top). This tool is part of Schlumberger's internal Internet hub, a Web-site accessible only by authorized Schlumberger personnel. PowerSTIM teams can use the intranet tool at any time, from any location with an Internet connection. For example, data uploaded from a field location in the Middle East by one team member can be accessed in minutes by a product center providing support or by another team member in an office in Houston.

The PowerSTIM intranet tool allows rapid integration of knowledge from several disparate sources to facilitate faster, easier and better teamwork. Project data uploaded by engineers are automatically incorporated into the PowerSTIM montage, which is built in a fraction of the time it would take each engineer just to handle and print various components separately. A montage is completed almost as soon as all data are collected. In fact, completion recommendations have been delivered before logging trucks leave a location.

A stimulation-optimization project begins when the project manager, or coordinator, selects experts from around the world who are notified by e-mail and assigned specific tasks. PowerSTIM teams should include petrophysicists, reservoir and production engineers and stimulation designers. This team should be involved as early as possible in the drilling and completion design process. Optimization success is related directly to project inception and timing. Projects that have a PowerSTIM team in place during the planning stages are usually extremely successful.

Once data are collected and analyzed, the PowerSTIM team designs a customized completion based on improved reservoir characterization. Again, because of the intranet tool, these efforts can take place miles from the source of data. Completion designs and completion results can be compiled and integrated into the montage, so that the entire history of a stimulation treatment is in one simple document. Running Monte Carlo and other economic simulations for critical well parameters also factors in risk.

From initiation of a new project through post-completion, post-stimulation analysis, the intranet tool essentially creates a virtual office for stimulation-optimization projects. Team members separated by hundreds or thousands of miles interact and exchange data efficiently and effectively to deliver completion and stimulation solutions “on line” and “in time” to meet client needs. A full and complete record is produced, just as if team members were working side by side.

PowerSTIM workflow using the intranet tool is an excellent example of how truly integrated solutions are implemented by drawing on worldwide technical expertise, fit-for-purpose technology and knowledge-management systems with state-of-the-art information technology. Quickly delivering completion recommendations is a key contribution of this workflow. Applications of PowerSTIM methodology and tools for candidate recognition and selection include:

- optimize profitability in heterogeneous reservoirs where conditions vary
- improve performance of marginal fields
- overcome completion problems or failures in areas where others are succeeding
- reengineer completions to maintain or exceed past production at costs that are lower, the same or higher, but economically justifiable.

Improving a Marginal Development

Kerns Oil and Gas Inc., San Antonio, Texas, used the PowerSTIM methodology to optimize completions in the Olmos and San Miguel tight-gas formations of South Texas, which include the Catarina S.W. and Dos Hermanos fields. Wells in these fields are drilled and completed to produce from either or both formations. Improving stimulation results could justify additional development of this marginal area, but acquiring permeability data to evaluate pay zones and design fracture treatments is difficult.
The Olmos formation in this region consists of individual sands 5 to 50 ft [1.5 to 15 m] thick over an interval of several hundred feet. Many individual sands will not produce naturally and permeability must be assumed, leading to miscalculations of fluid leakoff into the formation. Published permeabilities for laminated Olmos sands range between 0.07 and 10 mD with a variation based on local experience of 0.04 mD to several millidarcies. The Olmos formation has low compressive strength, and shales fracture as easily as sands. Values for Young’s modulus in another Olmos field range from 1.7 to 2.0 million psi [12 to 14 thousand MPa]. In the area where Kerns operates, hardness calculated from DSI log data indicates that Young’s modulus is between 1.2 and 4.8 million psi [8 to 33 thousand MPa]. San Miguel sands vary from 0.1 to 33 mD.

To improve completion techniques and well performance, a PowerSTIM team studied several wells and modified the completion techniques. First, high-performance UltraJet charges replaced standard perforating charges to increase formation penetration. Next, porosity and permeability measurements from CMR logs and mechanical properties from DSI logs were used to improve stimulation candidate selection. The team used CMR-derived permeability to determine leakoff and design fracture stimulations. Accurate compressional and shear data to derive Young’s modulus and Poisson’s ratio were obtained from DSI logs. FMI microresistivity images helped address fracturing fluid leakoff and well placement by identifying fault planes and preferred fracture plane (PFP) orientation. Cost per well for perforating increased $4,000 and stimulation costs were $20,000 higher, but initial production increased from about 400 to 1000 Mscf/D [11,500 to 29,000 m3/d].

In the first well, CMR-derived permeabilities were compared with estimated well production (above). The zone of interest with 17% porosity and

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was in the 3 ft at the bottom of the sand. Neutron grain distribution supported an interpretation of sand lies lignite and washed-out hole data. Late T2 but data were suspect because the section over-

conclusion.

production—an erroneous
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An interpretation based on

section that might have been bypassed. The completion interval and well productivity were antici-

Pore-size and permeability estimates from CMR data were used for the second well, which has two thick Olmos sands located close together (below). The low-permeability sand was tested and stimulated because it met the standard 12% density porosity and 12% resistivity cutoffs, but results were poor. This zone was plugged and the upper Olmos sand was completed successfully.

> CMR log and density log for two Olmos sands. An interpretation using density porosity alone indicated that the lower sand was more desirable. However, higher permeability in the upper zone correlates with long relaxation times in the NMR T2 distribution (top). Production results confirm this CMR interpretation. The lower zone was plugged after unsuccess-
fuial perforation and stimula-
tion (bottom). The upper zone was completed successfully. An interpretation based on density porosity alone indicated that the lower sand was the more desirable zone for production—an erroneous conclusion.

A CMR-based interpretation, which indicated that the lower sand has higher porosity and lower permeability than the upper sand, would have rec-

Permeability data are extremely important in all stimulation designs. Two FracCADE 3D fracture stimulation designs were compared for a third well (next page, top). The first design was modeled using permeability based on previous local knowledge, side-wall core estimates and published data for the region. The resulting fracture design length is less than required for optimal stimulation. To get the required fracture length and width, the treatment size would have to increased, which results in a more expensive and, at the same time, less efficient stimulation. The possibility of a premature screenout is also much higher with overdesigned jobs. The second design used permeability estimates from a CMR-Plus log to optimize the fracture designs and minimize potential job execution problems.

In a fourth well, DSI data were used in conjunc-
tion with CMR data. Young's modulus from sonic data varied from 2.5 to 4.5 million psi [17 to 31 thousand MPa] in sands and from 2.0 to 2.5 million psi [13 to 17 thousand MPa] in shales. Permeability varied from 0.003 to 0.5 mD in the sands. The fracture design for this well indicated a half-length of 800 ft [244 m]. Interference was a concern because of an offset well about 1000 ft [305 m] to the northwest. Sonic data show stress orientations even when borehole ovality, or breakout, is not apparent from FMI images, so DSI logs were acquired to determine PFP direction. Determining fracture orientation can also optimize well placement and gas recovery.

Directional data from DSI sonic logs and FMI images were used to determine proper well placement and ensure effective reservoir drainage. Most sands in this region have a NE-SW fracture orientation, but there is some variation. The FMI data corroborated this direction. The fracture direction was away from the offset well, so pumping was initiated. No connectivity or interference was detected.

Another issue in these fields was inadequate bit performance. It was taking 20 days to drill wells, and the resulting poor borehole conditions were adversely affecting formation evaluation and reservoir characterization. Overgauge and washed-out holes caused log measurements to be unreliable, wasted cement and hindered zonal isolation. A synthetic rock-properties log was developed to select and run proper bits. A stable Reed-Hycalog bit design cut drilling time to only
10 days, improved log quality to help identify additional pay and resulted in better cement jobs with less cement. This additional step ensured accurate data for optimizing future well completions.

Well completions in this area are now more successful (right). Previously bypassed sands that once appeared marginal are adding significantly to total production. Data-acquisition costs increased by $20,000 per well; perforating costs increased $4,000, and stimulation charges rose $30,000. However, comprehensive data acquisition and optimized completions have more than doubled production rates. Average well production increased from about 1 MMscf/D [29,000 m³/d], and finding costs dropped by a factor of three, from $1.47 to $0.48/MMscf.

Solving Stimulation-Related Problems

Fracturing the Morrow formation in southeast New Mexico, USA, is problematic. Morrow gas sands in this region are low-pressure and potentially water-sensitive, with permeabilities ranging over three orders of magnitude. The best wells are completed naturally; those in lower quality reservoir rock are fractured. To address water-sensitivity and avoid screenout while fracturing, a common practice is to pump low-viscosity foamed fluids with low proppant concentrations that yield narrow fractures with low conductivity. Operators in this area approach stimulation treatments cautiously and generally accept less than optimal results.

Most completions are planned using three generic guidelines: wells are completed without fracturing if zones produce at economical rates; fracture stimulation is a last resort if production falls below the economic limit; and aqueous fluid systems are avoided because of a water-sensitive formation. Although not universal, these approaches represent the thinking of many operators involved in Morrow development during the past 20 years.

Early attempts to fracture the Morrow with water-base systems were marginally successful. Studies suggested that poor results were due to water-sensitive clays or capillary-pressure effects that reduce reservoir permeability as a result of exposure to fracturing fluids. Low reservoir pressure exacerbates the latter. These issues...
were addressed by pumping treatments energized with nitrogen \([\text{N}_2]\) or carbon dioxide \([\text{CO}_2]\), and using methanol in fracturing fluids. However, stimulation results with these foamed systems have been inconsistent.

In higher permeability zones where near-wellbore damage is bypassed, small fracturing treatments using foams are successful, but in lower permeability zones where fracture length is critical to stimulation success, these systems do not provide consistent economical results. These treatments address water-sensitivity, but low viscosity, high friction pressure and chemical requirements increase screenouts and cost. Early screenout and low proppant concentrations leave wells producing at less than full potential.

Fracture-treatment designs that develop adequate hydraulic width and transport higher concentrations and volumes of proppant were needed to maximize production, but this required reliable values for reservoir parameters and rock properties. With a comprehensive understanding of the reservoir, stimulation specialists can design fluids and proppants to create hydraulic fractures that deliver high conductivity and optimal results.

Louis Dreyfus Natural Gas Inc. drilled the ETA-4 well in March 2000. Pressure data were not available, but a bottomhole pressure of 2000 psi \([13.8 \text{ MPa}]\) was measured in an offset Morrow well. Wireline logs identified a homogeneous, high-quality, 10-ft \([3\text{-m}]\) Morrow zone with about 14% porosity and 20% water saturation. Rotary sidewall cores verified the log interpretation. A zone of this quality should produce naturally, but high permeability and low pressure make the interval susceptible to drilling damage. Significant separation between resistivity curves confirmed deep invasion, so to overcome near-wellbore damage, the operator wanted to design a fracture stimulation in advance.\(^{14}\)

Reservoir quality in the ETA-3 well, completed two months earlier, was similar, but with half as much pay. This well was perforated and fracture stimulated down 5-in. casing with \(\text{CO}_2\) foam and high-strength, man-made ceramic proppant. Surface treating pressure was 5000 psi \([34 \text{ MPa}]\); maximum proppant concentration was 4 ppa; and there were indications of possible screenout near the end of the job. Post-stimulation production stabilized at 1.7 MMscf/D \([49,000 \text{ m}^3/\text{d}]\) and 500-psi \([3.4-\text{MPa}]\) flowing tubing pressure (FTP) at surface.

Because reservoir quality was equivalent and pay was twice as thick, the operator expected ETA-4 to be an excellent well. However, production after perforating was only 500 MMscf/D \([14,000 \text{ m}^3/\text{d}]\) with 220-psi \([1.5-\text{MPa}]\) flowing casing pressure (FCP), which was equivalent to an extremely damaged completion with a positive 45 skin. The next step was to determine optimal fracture length using actual reservoir parameters \(\leftarrow\).

To take full advantage of this quality reservoir, the operator wanted to design a more conductive fracture using higher than conventional proppant concentrations. However, because the offset fracture treatment indicated a possible screenout at 4 ppa, this would not be easy. Premature screenout limits production rates after fracturing and are common in the Morrow formation. Stimulation engineers consider near-wellbore tortuosity to be a factor that needs to be addressed to minimize the likelihood of a screenout \(\rightarrow\). Properly oriented perforations mitigate tortuosity effects. The maximum stress direction, or preferred fracture plane (PFP), is perpendicular to borehole breakout as indicated by FMI log data and oriented NW to SE in the ETA-4 well. This information was used to orient perforating guns in the direction of maximum formation stress using a Wireline Oriented Perforating Tool (WOPT) system.

Higher proppant concentration—6 versus 4 ppa—to increase fracture width was possible because oriented perforating reduces the risk of a premature screenout caused by near-wellbore tortuosity. At 6 ppa, the FracCADE program shows a fracture half-length of 300 ft \([91 \text{ m}]\) and a width of 0.15 in. \([3.8 \text{ mm}]\), twice as wide as
a 4-ppa design (right). This treatment appears to be overdesigned, but local experience suggests that to realize an effective 200-ft [60-m] conductive fracture, a 300-foot design target is not unreasonable considering the potential for fracture conductivity damage after fracture closure and production begins.

Treatment pressures highlight the impact of oriented perforations on job execution (below right). Pump rates for the two stimulation treatments are identical at 30 bbl/min [4.7 m³/min], but the conventional fracture stimulation shows a treating pressure of 5000 psi [34 MPa], while pressures with oriented perforation range between 3000 and 4000 psi [20 and 27 MPa].

Another important indicator is pressure response after pumping stops. On the conventional job, it takes 15 minutes for pressure to drop below 3000 psi, suggesting that net pressure was increasing and this job was close to screenout. For the oriented fracture, pressure stabilizes almost immediately, suggesting higher proppant concentrations could be placed. Advances in fluid systems and optimized fracture designs make it possible to use either foam or water-base systems to stimulate the Morrow formation.

Early production history for ETA-4 indicated a successful stimulation. Post-fracture production was 3.5 MMscf/D [1 million m³/d] with 1280-psi [9-MPa] FTP compared with 500 Mscf/D with a flowing casing pressure of 220 psi before stimulation. Because the goal was to bypass drilling damage, skin is a good indicator of fracturing success. Prestimulation production of 500 Mscf/D suggests a skin of 45, while a post-stimulation rate of 3.5 MMscf/D [99,000 m³/d] suggests that skin was reduced to -4.

Analysis shows that with 4 ppa maximum proppant concentration and 0.06-in. [1.5-mm] fracture width, the ETA-4 well would produce 2.2 MMscf/D [63,000 m³/d] at 1280-psi FTP. If fracture width is increased to 0.15 in., production rises to 3 MMscf/D [85,000 m³/d] with 1280-psi FTP. The well actually produced more, suggesting creation of a slightly wider fracture. Oriented perforating allowed proppant concentration and fracture width to be increased, eliminated premature screenout and the need to clean out wells after fracturing, and resulted in an additional 1.3 MMscf/D [34,000 m³/d]. The payout for incremental perforating costs was only three days.

Fracture designs for the ETA-4 well. Although fracture half-length and height are similar, fracture width using 4 ppa (top), as on offset well ETA-3, is half of that for 6 ppa (bottom).

Comparison of conventional and oriented fracture treatments. The biggest difference is in surface treating pressure. While proppant concentration steps from 1 to 4 ppa on the ETA-3 well and from 1 to 6 ppa on the ETA-4 well, treating pressures are significantly lower on ETA-4 than on ETA-3 as a result of orienting the perforations with the maximum stress direction, or preferred fracture plane.

Reengineering Completions

Ultra Petroleum, Inc., one of the most active operators in the prolific Jonah gas field of Sublette county, Wyoming, USA, wanted to reduce completion time and costs, and increase production. This field is a fault trap within a larger gas accumulation in the Green River basin. Production comes from the Upper Cretaceous Lance formation, a thick sequence of stacked, interbedded channel sands, overbank siltstones and floodplain shales from about 8900 to 13,500 ft [2713 to 4111 m]. The Lance formation is gas-charged, but noncommercial throughout much of the basin. Shallow overpressure makes gas production economical in the Jonah field.

Low permeability and multiple pay zones across large sections make it difficult to complete wells economically. The gross horizon is 2800 to 3600 ft [853 to 1097 m] thick with more than 100 separate sands that range from 2 to 30 ft [0.6 to 9 m] thick. Pay intervals consist of both individual 10- to 15-ft [3- to 4.5-m] zones and stacked channel sequences more than 200 ft thick. Porosity is between 6 and 12%, and permeability ranges from 0.001 to 0.5 mD. Each sand requires stimulation to produce viable rates.

The completion interval is grouped into stages with 50 to 200 ft [15 to 61 m] of gross pay that are fractured separately. If there are too many stages, costs increase significantly and return on investment is reduced. With too few stages, some sands are not stimulated adequately and production is compromised. The fundamental problems faced by engineers are determining which sands to complete and which to skip; how many sands to include and how to group them in stages; and how to isolate between stages after fracturing.

Historically, using limited-entry diversion over longer intervals to control costs minimized the number of fracturing treatments. Stages ranged from 100 to 450 ft [30 to 137 m] with 20 to 28 perforations per stage. After an interval was stimulated, the well was flowed to clean up and recover fracturing fluids, and to test productivity. One to two weeks later, fractured intervals were isolated with mechanical plugs—retrievable or drillable—or sand plugs, and the next interval was perforated and fractured. This process continued until the well was completed. Typically, three to six intervals were fractured per well over about five weeks. These traditional completions often cost as much as drilling the well, take a lot of time and yield disappointing results.

The PowerSTIM methodology was applied to this complex reservoir with impressive results.
and far-reaching impact on completion success. Once again, the key was to develop a model to estimate permeability, rock properties and individual sand-layer productivity.

The first phase of the project incorporated work done by Amoco, now BP, and Schlumberger to relate core and transient pressure tests to log responses.\(^\text{15}\) After traditional completion techniques developed by other operators were analyzed, several problems were apparent. Radioactive tracer surveys showed that many targeted sands were not stimulated, and production logs indicated only about 60 to 70% of pay sands were producing gas (previous page, top).

Sand plugs were difficult to place and often ended up missing or too low, resulting in costly procedures to reset them. Production logs revealed that there was no production from many upper sands in a fractured interval, but radioactive tracers showed proppant was placed in these zones (previous page, bottom). Many wells had the same problem, indicating that proppant from the near-wellbore region may be displaced when sand plugs are set before fracturing subsequent stages. Tracer surveys also indicate fracture containment, but net-pressure plots show considerable fracture-height growth. Even with limited-entry perforating for diversion, there may be connectivity between perforated and unperforated sands.\(^\text{16}\)

The Jonah reservoir lacked complete characterization. Fracturing jobs rarely screened out and sand plugs for zonal isolation frequently end up displaced into the formation, suggesting the potential to optimize stimulation designs by increasing treatment size. To make completion and stimulation decisions, the PowerSTIM team needed to evaluate key parameters, including stress gradients for fracturing model geometry and proppant selection, Young’s modulus for fracture width, leakoff for fluid optimization, and reservoir pressure for staging strategy and fluid requirements.

The greatest challenge was deciding how to acquire additional data without compromising profitability. This was accomplished by carefully planning strategic logging programs, minifracture treatments and pressure-transient analysis. Fracture gradient, Young’s modulus and leakoff parameters for fracture fluids were determined from minifracture treatments using the DataFRAC service (above). Dipole sonic logs were used to build near-wellbore stress models, calibrate stress profiles for sand-shale sequences and determine preferred fracture direction. These data confirmed stress values from minifractures. Fracturing models using more reliable stress measurement in sands and bounding layers, coupled with better Young’s modulus values, provided improved fracture height and width estimates. Cores were analyzed to understand fluid compatibility and verify rock mechanical properties. Early geologic interpretations assumed there were natural fractures with high fluid leakoff throughout the field, but image logs did not show significant natural fractures in the heart of the field. Lower than expected fluid leakoff from DataFRAC analysis and absence of natural fractures allowed pad volumes to be decreased, which reduced costs.\(^\text{17}\)

The geological complexity of this field requires a method for completing multiple horizons in a single day without sand plugs or mechanical isolation. This approach allows shorter intervals to be stimulated, increases production efficiency and improves development economics. Diversion with limited-entry techniques and sand plugs results in poor completion efficiencies. Mechanical isolation with bridge plugs or packers was complicated, costly and risky to retrieve by either conventional workover or coiled tubing.

To stimulate wells more effectively, the operator decided to fracture smaller vertical intervals and perform multiple treatments in a single day. The ideal diversion technique would allow cleanup of fracture intervals without needing to wash out sand or retrieve packers. By designing a tip-screenout, net pressure...
generated during stimulation is used to divert subsequent fracturing treatments into the next interval (below).18

After fracturing, wells are flowed to recover at least one casing volume of fluid and allow the fracture to close. The next interval is then perforated and fractured. This process is repeated until the entire producing horizon is stimulated. As many as 11 fracture stages have been performed in 36 hours, reducing the time required to completely stimulate a well from five weeks to less than four days, and increasing producing pay to more than 90%.

In previous wells where limited entry was used, an entire wellbore might have only 120 perforations. With the new completion technique, a single fracture interval can have 120 perforations. A well may have 1200 over the entire interval to reduce the risk of leaving pay unstimulated. The new completion techniques increase the maximum number of stages from 5 to 12 intervals per well. Fracturing designs included high proppant concentrations at the end of a treatment to maintain created width and maximize net pressure after fractures close.

Tubulars were the final aspect to be analyzed. Initially, well designs used 4- or 5-in. casing to accommodate high pump rates for fracturing large intervals. Because Jonah wells typically produce water and condensate, unloading fluids is critical to maintain production. After cleanup, 2½- or 2¼-in. tubing was run into wells under pressure using a snubbing unit. With shorter treatment intervals and improved fluids, fractures now can be placed effectively at lower pump rates, making 3-in. tubing feasible for casing (above). This tubular configuration defers tubing installation by several years and eliminates production limitations associated with small tubular sizes.

18. In standard fracturing, the fracture tip is the final area that is packed with proppant. A tip-screenout design causes proppant to pack, or bridge, near the end of the fracture early in a treatment. As additional proppant-laden fluid is pumped, the fracture balloons because it can no longer propagate deeper into the formation. This technique creates a wider, more conductive pathway as proppant is packed back toward the wellbore.
With this background in mind, a specific PowerSTIM project was undertaken to further reduce completion time and costs in Ultra Petroleum’s Jonah wells without jeopardizing production. Four reservoir rock types were identified, and correlations were developed to compute permeability with CMR logs on key wells, Platform Express logs on infill wells and RST measurements in wells where adverse hole conditions prevent openhole data acquisition. Similar correlations were developed to compute rock mechanical properties—stress, Poisson’s ratio and Young’s modulus. A unique zone-by-zone layering routine was developed to identify and evaluate each of the hundreds of distinct layers in the Lance formation. This routine eventually evolved into the ZoneAID program.

A method was then developed to combine formation evaluation and stimulation design results to predict production. This powerful tool allows a PowerSTIM team to quickly evaluate multiple completion scenarios and determine which combination results in maximum production for the lowest cost. Currently, the time from receiving log and well data to generating rate predictions for all sands is only about four hours. Schlumberger delivers a PowerSTIM montage, including individual stimulation designs, production forecasts and economic evaluations for as many as 17 fracturing stages, to Ultra Petroleum within forty-eight hours. Efforts are continuing to reduce this turnaround time even more with the help of the intranet tool.

However, the process does not stop here. In perhaps the most important step, key wells are routinely evaluated by running production logs after three to six months to measure contributions from each sand, make sure each sand was adequately stimulated and assess production predictions. Production logs and production histories are evaluated using PSPLTR and PROFIT software to make sure fracture-model conductivity and geometry are actually attained. By constantly evaluating and refining the optimization process, the PowerSTIM methodology can achieve remarkable accuracy.

Like many of today’s lean and aggressive energy companies, Ultra Petroleum relies on new technology, innovative solutions and collaborative working relationships for technical services and support, innovative technologies and new integrated solutions. New completion techniques based on extensive data collection reduced time to first production and completion costs while increasing production and recovery factors.

Eliminating sand plugs and other positive isolation between fractured intervals, and extensive flowback periods after each treatment saved money and almost four weeks of completion time (below). Reduced pad volumes, improved fluid and proppant selection, and optimized tubular design decreased costs. Overall completion costs were cut by 50%. Finding costs decreased from $0.45 to $0.23/Mscf.

When data are normalized for permeability and thickness, production from new completions is 8% more than from original completions and 30% higher than wells of other area operators, primarily from improved completion efficiencies.

^Continual completion improvements. Over an 18-month period, time to first production was reduced by about 27 days, or four weeks, primarily by completing Jonah field wells without sand plugs or other forms of mechanical isolation.
Data also indicated an increase in estimated ultimate recovery (EUR) for new completions (above).

Completion Optimization
Understanding reservoir characteristics across pay zones in a well, an entire field and within a basin results in optimized stimulation treatments and completion techniques that reduce costs, maximize production and increase hydrocarbon recovery. The PowerSTIM initiative uses an integrated approach to develop the required models for generating technical solutions or well-completion strategies that are transportable from field to field and company to company.

The positive impact and established record of stimulation optimization in the mature onshore field developments of North America are helping to extend acceptance of the PowerSTIM methodology into other areas both onshore and offshore, including regions like the Middle East.

A joint Saudi Aramco and Schlumberger project is now underway in the Hawiyah field, Saudi Arabia, to eliminate sand production and maximize production from the reservoir to meet the gas-deliverability target for this field. The project involves stimulation optimization for a group of 10 wells. Rather than undertake this effort internally, Saudi Aramco chose to utilize the PowerSTIM approach and form a team of experts to develop stimulation and completion solutions.

The PowerSTIM project manager is a Saudi Aramco representative. A Schlumberger project coordinator heads joint technical and operational teams. The technical team is made up of physicists, geologists, reservoir engineers and stimulation engineers from each company who work with the Saudi Aramco engineers that are assigned to designated wells. The operational team comprises Schlumberger field managers from wireline, well testing, cementing and stimulation, and coiled-tubing service segments who work closely with Saudi Aramco site foremen and senior engineers.

The first stage of this project—model development—was completed in early 2001. A comprehensive data set was developed to improve completion strategies and designs. Mechanical rock properties, hydrocarbon resource profiles and sand-prediction models were either developed or improved. In addition to optimal fracture design through integration of all available basin, field, reservoir and well data, this PowerSTIM project is generating and documenting best practices. Screenless completion guidelines were adapted and distributed for use along with sand-control guidelines for well flowback.

 Petrophysical models were initially applied to four wells. In February 2001, the first well was stimulated using recommendations based on reservoir and completion models developed by the PowerSTIM team. Early results were extremely encouraging. The project schedule calls for the remaining wells to be stimulated during the first half of 2001.

Collaboration on this project proved to be extremely beneficial, particularly between Saudi Aramco and Schlumberger, with interaction and workflow continuing to improve. Staff from each company appreciate the ability to contribute knowledge, experience and ideas to improve stimulation treatments and the well-completion process. Both companies benefit from the reduced engineering cycle time that is the result of expediting the learning process, emphasizing added value and targeting incremental production potential.

Stimulations based on estimates or on average reservoir properties may result in hydraulic fractures of insufficient length and width with excessive vertical height. Innovative methods to reliably establish the key parameters required for reservoir characterization, modeling and design program input overcome traditional limitations inherent in acquiring these data.

Optimized stimulation treatments use continuous wireline measurements from advanced well logging technology, core analysis, in-situ testing, and better data management, processing and interpretation coupled with fit-for-purpose fracture technologies to ensure more contained, conductive conduits deeper into formations.

The PowerSTIM initiative is about full-cycle engineering, quality data and in-time delivery of customized solutions. Procedures based on data acquired throughout a field, region-wide experience and application of careful reservoir evaluation are having beneficial effects on field development. In addition, better evaluation of formation characteristics allows fracturing fluids, proppants and volumes to be optimized. Schlumberger is positioned to provide data measurement, integration, formatting and presentation, as well as interpretation expertise, technical design and evaluation, operations quality control and global support.

The way solutions are developed and communicated within Schlumberger and externally to operators is changing as the industry moves away from static, or flat, documents and reports. Real-time information processing, data evaluation and life-of-the-well reports are becoming as important as the answers and solutions they generate. The latest information technology (IT) systems and knowledge-management technologies are providing us with methodologies and Web-based tools like the PowerSTIM intranet tool and montage for making informed decisions in a collaborative, virtual work environment. Through Internet meetings and videoconferences, regional data houses and visualization centers, we can work together without being in the same office. —MET