Drilling is a crucial part of field development. Operating companies can only optimize hydrocarbon production and recovery by drilling their wells in the best field locations. In the past, drilling was as much an art as a science. In many cases, drilling operations relied on personal skill and judgment, with key decisions being made with only a limited understanding of the subsurface environment. Today, drilling engineers can call upon a wealth of information and advanced techniques that eliminate much of the guesswork that characterized traditional drilling.

In this article, Sudhendu Kashikar reviews the latest drilling methods and technologies, and examines how they will shape future operations.
The development of rotary drilling methods at the start of the twentieth century provided the technical basis for effective oil and gas exploitation and thereby helped to establish the modern oil and gas industry. For decades, drilling operations were controlled by a small number of experts. These experts tried to interpret well conditions during drilling and relied on improvisation to overcome problems as they arose. Those who had a detailed knowledge of local geology and understood the types of problems that might be encountered in a specific location usually achieved the best results. However, success rates for wells drilled under this traditional system were highly variable.

The introduction of improved seismic methods and tools for more detailed reservoir characterization has given the driller vital information about drilling conditions during drilling and relied on improvisation to overcome problems as they arose. Those who had a detailed knowledge of local geology and understood the types of problems that might be encountered in a specific location usually achieved the best results. However, success rates for wells drilled under this traditional system were highly variable.

The power to deliver better wellbores that are sustainable improvements in drilling efficiency, avoid potential hazards, and optimize well placement beyond what was possible just a few years ago. Greater connectivity, and the secure data access that this allows, has been a key factor in these advances and will lead to profound changes in the drilling sector for years to come.

An established technology

Drilling engineers have long understood the potential benefits of steering their wellbores. The world’s first horizontal well was drilled near Texon, Texas, USA, in 1929. In the late 1930s and early 1940s, wells were drilled with horizontal displacements of 10 to 150 m, and the world’s first multilateral well was drilled in the Soviet Union in 1965 (Figure 2). By 1980, the Soviet Union had drilled more than 100 multibranch horizontal wells, including exploration, production, and injector wells. By the mid-1980s, drilling techniques had advanced significantly, but were still very different to those that can be applied today. In the 1980s, wells were drilled without the benefit of synthetic-base mud, top drives, steerable motors, polycrystalline diamond compact bits, or computers. Without these key tools and technologies, there were many problems for the directional driller to overcome.

Modern directional drilling methods are cost-effective and extremely versatile, and they offer significant advantages over vertical drilling for the recovery of oil and gas. Horizontal wells, for example, can improve production and increase reserves by intersecting natural fractures that cannot be accessed with vertical wells. This delays the onset of water or gas coning so that more oil is produced, and production from thin or tight reservoirs and waterflood swept efficiency are improved (Figure 3).

The introduction of rotary steerable systems (RSS) in 1997 marked a major milestone for drilling performance. The fully rotating drilling string proved more stable, less prone to sticking, and better able to facilitate hole cleaning and wall smoothing than the effect on the well. Continuous review and refinement of drilling operations.

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Figure 1: The real-time cycle promotes continuous review and refinement of drilling operations. These advances in technology and interpretation capabilities have given the driller the tools and the mechanisms necessary to reduce drilling risk and optimize well placement beyond what was possible just a few years ago. Greater connectivity, and the secure data access that this allows, has been a key factor in these advances and will lead to profound changes in the drilling sector for years to come.

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Accurate and powerful

The PowerDrive® RSS is a compact system, comprising a bias unit and a control unit, that adds only 3.8 m to the length of the bottomhole assembly (BHA) (Figure 4). The bias unit sits immediately behind the bit and applies force to the bit in a controlled direction while the entire drilling system rotates. The control unit contains self-powered electronics, sensors, and a control mechanism to provide the average magnitude and direction of the bit-side loads that are used to adjust well trajectory. The bias unit has three external, hinged pads that are activated by controlled mud flow through a valve. The valve exploits the difference in mud pressure between the inside and the outside of the bias unit. The three-way rotary disk valve actuates the pads by sequentially diverting mud into the piston chamber of each pad as it rotates into alignment with the desired push point—the point opposite the desired trajectory—in the well (Figure 4).

Once a pad has passed the push point, the rotary valve cuts off its supply and the mud escapes through a specially designed leakage port.

Improved drilling methods produce better wells

Fully rotating steerable systems have been tested and shown to minimize problems such as wellbore spiraling and ballooning. RSS systems optimize the efficiency of cuttings transport and reduce the risk of sticking. Other studies indicate that using an RSS reduces stress on running-while-drilling (LWD) systems and cuts bit wear. Good design and an effective RSS will minimize or eliminate undesirable effects such as bounce, stick-slip, whirl, and lateral vibration.

Fully rotating the entire steering system

reduces mechanical and differential sticking of the drilling bit where there are no stationary components in contact with the casing, whipstock, or borehole. It also reduces the risk of the BHA packing off.

improves penetration rates because there are no stationary components to create friction. The efficient removal of cuttings means that cuttings are not reprocessed during drilling.

enhances the flow of drilled cuttings past the BHA because there are no annular bottlenecks in the wellbore.

Enhanced production

The ability to land and position wellbores more precisely within the reservoir leads directly to better production. The more sophisticated RSSs, which have automated, closed-loop control of the steering response, can position wells more precisely than even the very best directional driller could using conventional technology. This ability to land and navigate wells more precisely within the best production zones provides an immediate benefit for improving the production performance of the well. Straighter, cleaner wellbores improve the flow rates for hydrocarbons by eliminating water sumps and gas crests (Figure 6).

Improved reservoir access and drainage

In areas where three-dimensional directional drilling control is troublesome, RSSs can provide a much wider range of well-trajectory design options at low operational risk. This has proved particularly beneficial in fields where a lack of directional drilling control had limited well designs to simple, two-dimensional wells and thus restricted reservoir access and field-drainage patterns. With the introduction of rotary steerable drilling techniques to these fields, producible reserves are increased through improved reservoir access and more efficient drainage patterns.

Minimized lost-in-hole time

Continuous pipe rotation, smoother and less tortuous trajectories, and overall improvements in hole-gauge quality help to reduce stuck-pipe and lost-in-hole incidents. A study comparing lost-in-hole incidents for RSSs with those for conventional BHAAs showed the RSS lost-in-hole rate was only 15% of that experienced with conventional systems.

Improved safety

When drilling programs are conducted with RSSs, fewer trips in and out of hole should be required. RSS methods extend the life of drill bits, which results in more footage per bit and, therefore, fewer trips for bit changing. In addition, continuous rotation at high rotary speeds results in very efficient hole cleaning and removes the need for many short cleaning trips. RSSs are also much more versatile and should be able to drill all of the required section trajectories (such as build, drop, tangent, and turn) using a single BHA design, which means fewer trips for BHA change. This dramatic reduction in tripping saves time, reduces drill-floor activity, cuts handling of tubulars, and, ultimately, increases safety.

Reduced tripping activity can be measured by plotting the footage drilled against the total amount of pipe tripped over the course of a project. In some cases, the introduction of RSSs has reduced tripping by almost 50%.

Reduced environmental impact

Drilling with rotary steerable assemblies results in a more in-gauge hole compared with drilling with steerable motor systems. This gives smaller volumes of drilled cuttings waste and lower drilling fluid losses. For example, if the hole in a 12 1/4-in section were drilled overgauge to an average diameter of 12 in, this would represent an increase of about 30% in cuttings waste and, correspondingly, a 30% lower annular velocity compared with drilling the section in gauge (Figure 7).

Figure 4: The PowerDrive RSS produces high-quality boreholes at high ROPs.

Figure 6: Conventional drilling technology produces tortuous wells. In horizontal producers, this can restrict the flow of hydrocarbons (a). Flow rates are maximized when the borehole is smooth and straight (b).

Figure 7: Wells drilled overgauge generate more cuttings waste and are drilled at a lower annular velocity. All of the RSS-related improvements listed combine to deliver time savings, improved safety performance, and greater cost efficiencies that translate into lower production costs for field operators (Figure 8).
The tools for the job

Drilling technology must be flexible and enable the engineer to design and execute the most appropriate drilling program for any well. There are often considerable variations across oil-and-gas-bearing formations. Even adjacent wells may be significantly different, and each can exhibit unique temperature, pore-pressure, permeability, and lithological conditions. The industry needs an integrated drilling tool that can be adapted to these local variations and that will meet the specific needs of each customer.

For example, the PowerDrive Xceed RSS has been designed to excel in harsh environments. It is a fully rotating tool that provides high levels of accuracy and reliability in extreme drilling applications.

Maersk Oil Qatar AS used the PowerDrive Xceed system to drill thin sands in the Nahal Umr reservoir in Qatar (Figure 9). The system provided excellent geosteering capability, with the bit staying in the provided excellent geosteering with high levels of accuracy and reliability in extreme drilling applications.

The next step

As the exploration and production industry extends its operations into new areas, there is increasing pressure on service companies to provide tools with higher levels of reliability that can complete demanding drilling programs quickly and cost-effectively.

The availability of near-bit measurements in real time ensures accurate, efficient drilling and wellbore placement. The efficient downhole systems and the automatic inclination hold provide a smooth tangent section and improve the accuracy of the true vertical depth in the horizontal section—critical for maximizing recoverable reserves and the well’s production potential.

A measurement-while-drilling (MWD) type traxial sensor package close to the bit provides accurate azimuth and inclination directional information, which enables fast, responsive directional control in either the automatic or the manual operation mode. Once a target formation has been penetrated, the trajectory can be locked in using the inclination-hold functionality. No further input is required from the directional driller. Steering decisions are further aided by an optional real-time azimuthal gamma ray measurement and imaging of the wellbore to provide information on formation dip or fault boundaries. An azimuthal gamma ray sensor 2 m from the bit enables drillers and geologists to identify bed boundaries quickly and thus respond faster to formation changes in order to optimize well placement. Casing and coring point detection are optimal, penetration of the formations to be cored is minimized, and the chances of drilling through a potentially valuable core section or wasting time coring an uninteresting formation are significantly reduced.

High-performance drilling with a motor

When a PowerDrive RSS steerable motor is run in conjunction with a PowerDrive Xceed system, all of the drilling energy is concentrated at the bit. This configuration can improve the RSS’s eliminate slip/stick and unpredictable torque, maximize dogleg severity, drill a smoother hole, and increase bit life (Figures 10 and 11). PowerDrive RSS steerable motors are positive-displacement mud motors that incorporate a stabilizer and a bent-housing section that permits rotary drilling in vertical, tangential, or horizontal sections of the hole as well as oriented drilling during kickoffs or course corrections. The surface-adjustable bent housing provides flexibility as orientation requirements change.

The PowerPak motor’s modular design meets a full range of directional drilling requirements. The superior design of the tool features short bit-to-bend and bit-to-stabilizer spacings to enable high surface rotary speeds for improved hole cleaning.

Formation evaluation while drilling

Two decades ago, formation evaluation was usually conducted using wireline tools that were introduced to the borehole once drilling had been completed. The availability of near-bit measurements in real time ensures accurate, efficient drilling and wellbore placement. The efficient downhole systems and the automatic inclination hold provide a smooth tangent section and improve the accuracy of the true vertical depth in the horizontal section—critical for maximizing recoverable reserves and the well’s production potential.

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The big picture from the borehole

Although LWD and MWD tools have been available for many years, it is only recently that advances in data transmission and interpretation have progressed to generating accurate images of the wellbore. These images are based on real-time data and offer insight into what is really happening downhole.

Typically, a high-quality image is drawn from detailed, 3D resistivity data. A resistivity tool similar to the wireline-deployed FMI Fullbore Formation MicroImager tool supplies these data. The resistivity tool is capable of identifying wellbore features and characterizing faults, cementation changes, and threaded or spiraling boreholes caused by bit whirl. Software converts the resistivity data into 3D wellbore images that can be viewed from any angle using simple mouse movements.

The resistivity measurements are transformed into 56 azimuthal sectors around the circumference of the wellbore to provide extremely detailed images.

Current imaging-while-drilling technology is sufficiently fast and accurate to facilitate geosteering while drilling. Modern software and MWD telemetry systems provide a clear insight into 3D wellbore features, well placement within the reservoir, wellbore stability issues, formation dip, and structural configurations. Combining resistivity and density services with real-time logging images and geosteering techniques will help operators to reduce risk and overcome some of the geological uncertainties encountered while drilling complex wells.

Ultrahigh telemetry rates (up to 12 bps) have been used to optimize horizontal well placement and to warn of wellbore stability issues before they jeopardize operations or impact on drilling costs (Figure 13). Transmission of high-quality, real-time azimuthal and image log data is possible, even in cases where penetration rates are high.

When resistivity images are transmitted uphole to present the wellbore in four quadrants. This information can be wrapped into a 3D image of the wellbore, which helps the drilling team to optimize well placement using geological markers. Armed with this information, the drilling engineer can make rapid adjustments to the wellbore trajectory, relative to geological bedding planes or faults, and can modify steering while drilling.

Wellbore stability problems are detected using ultrasonic caliper logs from density LWD tools. Hole enlargement or washouts can be identified while drilling or during subsequent trips. This helps to monitor wellbore stability and enables adjustments to be made to mud weights or effective circulating densities as required (Figure 14). Wellbore stability problems can be confirmed using ViSION* Formation Evaluation and Imaging While Drilling technology that incorporates azimuthal density/neutron viewer software, which provides density-image and caliper data while drilling.

The azimuthal density/neutron viewer also generates 3D images and caliper logs that, when combined, make it easier to understand wellbore conditions during drilling. In addition, the 3D density images and ultrasonic caliper information enable engineers to characterize wellbore instability mechanisms and then resolve them. This is vital in completions where penetration rates are high and can make rapid adjustments to the wellbore trajectory, relative to geological bedding planes or faults, and can modify steering while drilling.
What could possibly go wrong?

Oil and gas companies spend around USD 20 billion on drilling each year. Unfortunately, about 15% of this is attributed to losses. These losses include materials such as drilling equipment and fluids, and deficiencies in drilling process continuity (called nonproductive time) that are incurred while searching for and implementing remedies to drilling problems (Figure 15). Avoiding drilling problems cuts finding and development costs and enables oil companies to focus on their core business—building and replacing reserves.

Every well presents problems: the main challenge for drilling engineers is to manage the drilling risk in a way that prevents small problems from escalating. Most of the time spent drilling wells, and most of the cost, is associated with cutting down through the rock sequence above the reservoir. Knowing what the potential risks are and where they are likely to occur helps to keep the drilling program on schedule.

There are various problems that can trouble drilling engineers (Figure 16, a–n). For example, drillpipe can become stuck against the borehole wall through differential pressures or by lodging in borehole irregularities; skill and force are required to free it. When sticking cannot be resolved, the only solution may be to abandon the stuck portion and drill a sidetrack around it. This changes the drilling program completely and may significantly increase the well's cost.

Drilling at high ROPs can save time and money, but when this high rate is accompanied by a low drilling rotation rate or a mud flow rate that fails to lift rock cuttings to surface, the result is stuck pipe. The faults and fractures that the wellbore encounters open conduits for loss of drilling fluid to the formation. Excessively high mud pressure can fracture the formation and cause lost circulation. However, if the mud pressure is too low, it will fail to keep high-pressure formations under control and can lead to gas kicks or blowouts.

Drillstring vibrations can weaken and destroy pipe and equipment as well as seriously damage the wellbore. And some problems, even if they do not completely suspend the drilling process, jeopardize subsequent logging, completion, and production.

Drillers who have to decide how best to correct these problems face tough challenges: there are many factors for them to consider. For example, increasing the mud weight to control wellbore stability in one interval in a well may cause fracturing elsewhere. Often, the most effective solutions cannot be widely applied, as many drilling-related problems are well- or field-specific. The key to successful drilling is to develop a sound plan, to update this continuously as new information becomes available, and to inform all the relevant personnel. The plan must include procedures to follow under normal circumstances and methods for dealing with the most likely and the most severe problems that could be encountered.

Despite these challenges, successful drilling should be a routine process for properly trained personnel who are following a well-defined drilling procedure and who have sufficient data and tools for interpretation.
Real-time dip information, provided by the LWD resistivity imaging tools, can be used to view geological structures and reduce the uncertainties in earlier geological models. Production teams can also analyze surface seismic data to establish the presence or location of erosion surfaces that might jeopardize the well trajectory. Data transmission from the rig site enables experts to observe the wellbore remotely and to anticipate changes in the bedding plane and the structural behavior of the reservoir.

An azimuthal density/neutron viewer software also enables structural dip picking from images. This can be used in combination with the real-time data for structural interpretation. Bed dips and layer thickness are also characterized for the evaluation of structural cross sections. The reduction in risk and geological uncertainty will make wellbore imaging an essential tool for companies operating in geologically complex fields.

LWD VISION tool eliminates the need for a pilot hole.

The VISION drilling tool has helped to save time and reduce costs by enabling several operators worldwide to drill deepwater production wells without first drilling a pilot hole. The geological drilling campaigns used real-time LWD images and bit resistivity data to land the well in the reservoir. Accurate well steering and placement require significant prejob planning in order to minimize drilling risks while steering using geological criteria. The use of LWD images in real time was a key element in predicting undesirable events that might otherwise have jeopardized the success of the project. In this well, subseismic faults and premature entry into the shale zone occurred. The interpretation of the available log and image data was critical to the decision-making process during drilling and ensured reentry into the reservoir.

The path to better wells

Drilling optimization and the benefits it brings cannot be achieved through tools and technology alone. Drilling and production engineers require risk-management systems to help them to optimize wellbore construction and performance, and to learn from previous drilling programs. This approach requires detailed planning, real-time control during execution of the drilling plan, and a method for reviewing performance.

The first challenge for a new drilling program is to link all the relevant expertise. This means that all parties can observe the well’s progress in real time and that the drilling engineer has the full support of an expert team, should the well encounter any difficulties. Modern connectivity systems such as the InterACT™ real-time monitoring and data delivery system make this possible by linking remote locations to field offices and corporate headquarters through secure Internet and intranet connections (Figure 17).

Right first time

As with all offshore operations, drilling is an activity that field operators want to complete quickly and cost-effectively. The keys to avoiding problems while drilling are assessing and managing risk, and optimizing well construction through detailed planning and real-time monitoring during the execution phase. Predrilling analysis and prediction, with real-time updating as drilling progresses, enable the drilling engineer to anticipate potential problems ahead of time and to solve them proactively. No Drilling Surprises (NDS) is a focused process that covers all aspects of well planning and execution, and delivers relevant information to the appropriate personnel at every stage in the drilling operation. There are three phases in an NDS project, see Figure 18.

Continuous updating of the living well plan helps the asset team to ensure that drilling decisions are based on accurate and up-to-date information and that they will not compromise hydrocarbon production recovery, or safety.

Technologies to meet key challenges

Growing market demand has created a broad spectrum of drilling services. Today, leading service companies are investing heavily in their own research and development to keep pace with industry needs and are participating in collaborative efforts with their customers. New products and services are being introduced to fill the gaps in drilling-services packages, and companies are starting to integrate drilling data with seismic, logging, production, and other reservoir data. This integration has led to benefits in areas such as stimulation, completions, and production optimization.

Balancing costs and benefits

Many operators, while acknowledging the technical advances that have been made in drilling, would like to see more technology aimed directly at reducing costs. Although costs appear to be falling in many areas, for example, software, well costs are not coming down. In real terms, some wells cost more today than they would have done 5 or 10 years ago. However, these higher costs do reflect the technical
understanding of the reservoir and its production, it can optimize well placement and select the best perforation zones or drilling trajectories.

Over the next decade, worldwide oil demand is projected to increase significantly, especially within the developing economies (Figure 21). Published estimates indicate that the reserves to meet this demand are available, but that they are usually more difficult and costly to produce. Reserves located in remote or challenging environments such as deep water or environmentally sensitive regions, or those that are considered nonconventional such as coalbed methane or heavy oil will require substantial research and development to devise suitable extraction solutions (Figure 21). The key to success will be finding economically viable methods to tap those reserves, despite the increased technical complexity that will be necessary.

Recent advances in wellbore-construction and production-enhancement techniques have been key contributors in this drive to meet technical challenges while reducing costs. Until now, the demand for stimulation services has been largest in North America, but demand is rising quickly in other parts of the world. Even in the Middle East, which contains many of the world’s most prolific reservoirs, depletion and production problems are starting to affect field performance and production-enhancement services are being investigated. Interest in unconventional resources is increasing globally, a sure sign that easy oil and gas production may soon be a thing of the past.

Reaching further, drilling smarter

As operators locate satellite fields and bypassed zones around a main reservoir, they may seek to develop these with extended-reach wells. However, for extended-reach wells to succeed there must be a careful assessment of risk. Extended wells can reach under urban centers or protected wilderness sites to tap oil and gas that would be inaccessible using any other approach.

Achievements of recent years, as the industry drills deeper and more complex wells.

Well construction costs may be rising, but the aim of reservoir development technology is to optimize reservoir exploitation using a few advanced wells that significantly outperform their conventional counterparts. nowhere has this been illustrated more clearly than in Russia, where a field development plan for 57 vertically drilled wells was recently scrapped in favor of two geosteered horizontal wells. The total field production from the original plan was estimated at about 2,000 m³/day with a 19-year life. Production from the two designer wells totals 5,000 m³/day and depletion is expected in 7.6 years.

Brownfield drilling

Today, most of the world’s oil production comes from mature fields (Figure 19), and some of those brownfield assets are over 30 years old. The industry is working hard to prolong the lives of these fields, to optimize production from them, and to improve recovery factors through remediation and production-enhancement technologies. However, there are many technical and economic challenges to be overcome in mature and brownfields. In these fields, drilling expenditure must be justified by the value of the incremental production from the asset (Figure 20). In recent years, significant progress has been made in this area by developing technologies designed to combat the decline of older fields and to add capacity for the future. Once the company operating a brownfield asset has a clear understanding of the reservoir and its production, it can optimize well placement and select the best perforation zones or drilling trajectories.

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Figure 23: delineation wells, which are discarded these would normally be vertical wells. In a newly discovered prospect, maps required drilling additional small to justify a new platform. Undrilled locations, including the operator with several promising and seismic interpretations provided amount of oil in place. Revised maps field indicated that the booked economics dictated that every new well should produce oil to cover or offset drilling costs. The first prepared bottomhole location was over 8 km from the platform, and meeting the objectives of this well would require going beyond the range of normal development drilling. Ultimately, an extended-reach well was directionally drilled, to a then world-record measured depth of more than 9,200 m, while using real-time LWD services to provide formation evaluation in a timely and cost-effective manner. The success of this well led to an extension of the drilling campaign. Subsequent wells, while not reaching as far from the platform, used LWD sonic and resistivity logging tools to provide real-time seismic correlation, porosity data, and hydrocarbon evaluation. These data enabled the operator to optimize costs and make decisions much more quickly. Dramatic rise in drilling efficiency for Middle East operator In the Middle East, Schlumberger has helped one operator achieve a 52 % (USD 1.5 million) reduction in total well costs. This resulted primarily from a 94 % increase in drilling efficiency per bit run, which persuaded the field operator to replace conventional motor technology throughout the company’s ongoing field program with the PowerDrive system. During the second phase of the multilateral program, the operator needed increased ability to overcome obstacles in the highly faulted and laterally variable sandstone reservoir. Nearly 90 % of these wells required openhole sidetracks for geological realignment. The available seismic data defined the heavily faulted area, and sidetracks were imperative. Steerability and directional control in bore sands; geosteering between different sand layers; abrasion; excessive wear; and hole cleaning were among the obstacles to be overcome. The PowerDrive Xceded system met the challenge and exceeded expectations on cost and time savings. Reduced wellbore tortuosity cut trip time by 68 %—a direct result of improved hole quality. The operators used the PowerDrive Xceded system to drill the longest well in the field and, for the first time, managed to drill the sandstone section (4,172 m) in one run.

The way ahead
The demands of modern oil and gas exploration will continue to shape the drilling-services sector. In mature and marginal fields, operating companies expect complex wells, excellent reliability, and low drilling risks at reasonable costs. As a result, manufacturers and service suppliers will have to continue to improve their technology and provide more efficient equipment throughout every area of the drilling process. To achieve this goal, manufacturers and service companies will have to work in close cooperation with customers to answer their specific needs. Collaborating with customers
There are many examples of collaborative projects for developing new technologies and processes with customers. For example, Schlumberger Drilling and Measurements is currently working with HP and Shell on a through-tubing RSS that is designed to reduce the costs of sidetracking from existing wells to reach small pockets of hydrocarbons. In the Middle East, Schlumberger is working in close cooperation with operating companies to develop and introduce 3D visualization rooms for integrated well planning and remote support through real-time data transfer and virtual-reality technology (Figure 24). Some operating companies are using software packages that help them to produce integrated well designs that bring geophysicists, geologists, and drilling engineers together to work on the same model. This enables the team to identify areas of interest, select targets, and work on the well path in an integrated process. Real-time visualization and the use of secure Internet links, such as the InterACT system, also enable companies to identify potential problems before they affect production. Operating companies that use virtual-reality systems for well planning report these have led to optimized designs that help to save time and money. Visualization technology has a proven track record and is constantly under development. For many companies, the major challenge is not introducing the systems, but modifying the way that departments and individuals interact—changing the ways in which they work and learn together.

Figure 24: Advanced visualization facilities enable field operators to assess reservoir conditions within a multidisciplinary framework.
Cooperation—the key to long-term success

In many fields, the drilling-services providers are only called in once the targets have been selected and the drilling program has been sketched out. This leaves very little scope for the service provider to help reduce costs or increase the efficiency of the program. When drilling-services providers are present from the early stages of field development and intimately involved in the planning process from the conceptual target selection, then their potential impact is much greater and the cost savings can be immense (Figure 25). Targets can be selected to tie in with the optimal drilling surface location or slot, and targets may be linked to increase the reservoir penetration with a single wellbore. Well profiles can be optimized by reservoir engineers and petrophysicists to ensure the optimal trajectory, and the field can be planned to ensure that anticollision issues are addressed. In addition, involving the drilling-services’ drilling engineers at this early stage enables early optimization of the BHA. All these factors, when added together, can significantly reduce well costs.

Developing relationships characterized by openness and trust between operators and contractors is fundamental to team building. Even without financial incentives, close cooperation encourages people to be proactive and find new ways to boost performance.

Assessing performance

For drilling performance to improve as a field development or contract progresses, performance must be benchmarked effectively. The key performance indicators (KPIs) must be genuine measures of drilling performance, and must be agreed upon by the operator and the provider in advance. As drilling advances and the number of wells increases, the learning curve can be assessed and the impact of various drilling services can be evaluated. Typically, drilling-services companies have been assessed on and compared using tool reliability in terms of circulating hours. While this provides a simple way to compare suppliers, it does not drive performance, and leading companies are trying to use KPIs that better reflect the impact that a service provider can have on drilling performance. For example, Schlumberger is trying to move to more representative KPIs such as meters between failure and meters drilled per circulating hour, which are much more closely tied to an operator’s own performance metrics when a well is drilled.

By crossplotting KPIs suggested metrics against each other, it becomes apparent that after a certain base level of reliability is achieved (meters between failures), savings from increased reliability become very small compared with those achieved through increased effective performance (meters per circulating hour). As the effective performance improves the drilling efficiency, the well cost continues to be significantly reduced. Performance also directly affects the number of sections drilled before a failure occurs, so, while no increase in reliability would be seen in terms of traditional reliability KPIs such as mean time between failures, the reliability measured as meters between failures will continue to improve.

Meeting the targets

Operators want strong production from every well they drill, so justifying a drilling campaign on prospects other than certainties has become increasingly difficult in recent years. As a result, operators and service providers must work together to ensure that the targets are selected, planned, and drilled correctly. To help the operating companies reach their business goals, service companies must understand the financial limitations and find a way to work profitably within them.

The development of new technology should be driven by the operators’ needs and only introduced when a business benefit can be clearly demonstrated. This is where the use of performance-driven KPIs becomes invaluable. Although new technology often has a reliability risk, its use may be justified if it offers a step change in performance. To help operators weigh these issues, it is essential that service companies be involved early in the planning process. This enables better technical solutions to be proposed and planned to address the needs of any project.

| Figure 25: Choosing an integrated service company to cover all aspects of drilling lowers costs, saves time and reduces the administrative burden on operating companies. |

| Figure 26: Drilling technology has advanced rapidly over the past 30 years. The development and introduction of new tools has enabled engineers to reach deeper and more complex targets in frontier areas and established oil provinces. |