In recent years, the oil and gas industry has been honing its ability to drill increasingly longer high-angle wells along increasingly convoluted well paths. The horizontal lengths of these extended-reach wells are today measured in kilometers and miles and link multiple isolated deposits with a single wellbore.
Innovative technology is marked by its ability to break new ground. In the world of extended-reach drilling, that standard is literal. In 1997, BP set the pace when it drilled a horizontal section of more than 10 km [about 6 mi] in a well at its Wytch Farm field in England.\(^1\) Since then, the industry has repeatedly extended that mark. As of this writing, the record horizontal length is more than 10.9 km [6.8 mi] and the record measured depth is 12.3 km [7.6 mi] in a well offshore Qatar.\(^2\)

As operators look to tap their own isolated reserves through extended-reach drilling (ERD), they may be tempted to simply replicate what has been done before. However, because seemingly small changes in ERD parameters may have significant impacts on completion options, it is essential that engineers plan each extended-reach well as a unique engineering-based project.

For example, to facilitate installation of intelligent completions, it is important that the wellbore have a relatively large diameter and a smooth profile. Intelligent wells often include production strings with externally mounted instrumentation. That equipment may be damaged during installation if the annular space between the tubular and casing walls is too narrow or irregular. A less complex completion, on the other hand, may afford the operator the luxury of rotating the casing or applying high downward loads to force it through high angles and tight spots, thus eliminating the need for building extra annular space into the drilling program.

Proper planning must include follow-through. In executing ERD plans, experienced drilling engineers often perform familiar-seeming operations in an unfamiliar manner. To ensure that all involved perform their tasks according to ERD guidelines, training in best practices is essential for personnel both in the field and in the office.

Much of the progress in drilling longer horizontal reaches has been attributed to improved technology in two areas: more-responsive steering and more-accurate real-time measurement capabilities. This article, however, focuses on a third component of the industry's advance: the development of best practices and the importance of connecting lessons learned from engineering, technology, training, supervision and postjob analysis to drilling the next extended-reach well.

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Defining ERD Wells

An ERD well is defined as having a horizontal departure/true vertical depth (HD/TVD) ratio of more than 2.0 (above). This ratio provides a crude indicator of well complexity; the higher the ratio, the more complex the well. But it is only a basic indicator of how difficult the well will be to drill and complete.

Drilling to targets located at a significant horizontal distance from the surface location usually requires more than drilling vertically, turning a corner and drilling horizontally. Depending on such formation characteristics as temperature, pressure and rock properties, the drilling team determines weight on bit (WOB), drillstring rpm, mud weight and other parameters. All these are tempered by the planned trajectory of the well and the build and drop angles and azimuthal turns necessary to deliver it. This last has become a significant factor in extended-reach well planning in recent years as sophisticated steerable and LWDD technology has allowed operators to use fewer, more-complex 3D well paths to optimize reservoir development.

Extended-reach wells are also generally categorized as very long, or very shallow TVD (next page). Each has its own challenges. Very long, or ultraextended wells, can be difficult to drill and complete because they may encounter high torque and drag forces. Circulating pressures may be elevated to overcome frictional losses as the drilling fluid is pumped down the drillstring and back up the borehole-drillpipe annulus.

Shallow TVD wells are usually drilled in unconsolidated formations with relatively low fracture gradients. The resulting narrow fracture-gradient–pore-pressure window becomes increasingly important as the wellbore extends horizontally and equivalent circulating densities (ECDs) continue to rise. Also, when the distance from the rig to the targeted reservoir section is relatively short, shallow wells may have to be turned from the vertical at a sharp angle. The resulting trajectory can lead to torque and buckling problems on the drillpipe and on completion tubulars.

When an extended-reach well includes a deep TVD, it may also be limited by drillstring tension and high side forces that introduce casing and drillpipe wear concerns.

Subsets of these basic well types include deepwater wells, 3D wells and those whose design is constrained by the limitations of the available rig. Extended-reach wells in deep water are uncommon because moving a floating rig over the target formation is usually a better solution than drilling horizontally. However, as production rates at fixed deepwater production platforms decline, the fields they serve may become candidates for extended-reach wells drilled to connect with outlying reservoirs.

When a deepwater extended-reach well is a better option, low fracture gradients—caused by water replacing thousands of feet of overburden—exacerbate the need to closely manage ECD. Additionally, because of the long vertical section between the seafloor and the surface, more weight is hanging from the rig's traveling block, and pipe tension is significantly increased. This extra tension creates large side forces, which may lead to casing wear as the drillpipe is pulled up through build and drop angles during backreaming operations.

Deepwater operations also affect drilling fluid properties in a manner that can impact hole cleaning. As the mud travels from the surface, it is cooled significantly by the near-freezing water at the seafloor. It is then heated to formation temperatures at the bit before returning to seafloor temperatures at the base of the riser. This process may change the drilling mud rheology, affecting its carrying capacity or the ECD loads imposed on the wellbore. In extended-reach wells, mud weights must be carefully controlled. This is one more instance in which the margin of error is smaller in extended-reach wells than in vertical wells.

Complex 3D wells have proliferated in recent years as the industry has developed and adopted increasingly sophisticated rotary steerable and
MWD tools. These wells are characterized by numerous significant azimuth changes designed to keep the wellbore in line with its targets.

Rig-limited wells are those drilled from drilling units with inadequate hook load or pump capacity. Many drilling engineers treat these wells as a distinct ERD category because the rig’s shortcomings force them to use technology that would otherwise not be required.

Planning

Extended-reach wells are drilled for numerous reasons: to contact as much reservoir with the borehole as possible, to reach several widely distributed hydrocarbon deposits from a single location or to remove surface operations from environmentally sensitive areas. Driven by environmental concerns, one of the most successful ERD programs was carried out in the BP Wytch Farm field on the south coast of England. In 1993, the operator chose to access offshore oil deposits beneath Poole Harbour using high-angle, long-reach wells drilled from closely spaced surface locations on land. The first well had a horizontal reach of 3.8 km [2.4 mi]. The project culminated in 1999 with a 10.9-km horizontal-reach well.

At the time BP broke the 10-km mark, the company used teams that consisted of up to 100 people representing all the entities involved in the drilling effort. Before each well was started, assigned personnel were brought together for one- to two-day workshops. They were first told how company global objectives related to the Wytch Farm well they were planning. Then, sub-surface, drilling, directional, mud and completion engineers described the technical details and potential hazards of the well that was about to be spudded.

The teams then broke into smaller groups of five to eight people who reviewed and set target times for each phase of the well, such as drilling a section or running and cementing a casing string. Each of these phases was then divided into its smaller components. The small groups brought their conclusions to the assembled team and created an overall drilling plan from the various pieces. Throughout the drilling of the well, the team measured actual progress and targets against the plan and devoted time to discussing the root causes of any problems that had occurred.

Such meticulous planning and follow-through is ideal for complex and extended-reach wells, and experts often cite the BP approach as the reason for the Wytch Farm successes. The key to proper ERD plans is to make them detailed and specific to each well. It is also useful to create and maintain a team with representation from all relevant disciplines from the very beginning of the project until its completion.

The time required to adequately plan an extended-reach well depends on numerous factors including well depth, length, complexity, rig availability, location and logistics. But many engineers consider a reasonable planning period to

3. ECD is the effective density exerted by a circulating fluid against the formation. The ECD is calculated as: $d = \frac{P}{0.052d^2} \text{pounds per gallon}$, where $d$ is the mud weight in pounds per gallon, $P$ is the pressure drop in the annulus between depth $D$ and surface (psig), and $D$ is the true vertical depth (feet).


5. Backreaming operations pass a tool of a larger OD than the drill bit through a previously drilled-out section of the well to increase hole diameter.

6. The hook load is the total force pulling down on the rig’s hook from which all drilling equipment—including the kelly, rotary and drilling-string—is attached and from which all other well equipment is being lowered into, or pulled out of, the wellbore.


Offset Well Data Review (OWR)

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Extended-reach well planning. ERD programs require completion of major steps comprising many parts before a drilling program can be delivered to the field. The offset well data review (OWR) allows operators to identify key ERD well-design issues. A preliminary well design (PWD) is then generated to establish feasibility, risks, equipment requirements, contractor needs, scope of work and a cost estimate for the project. A detailed well design (DWD) is a refined PWD that includes final drillpipe, casing and rig specifications, tenders for contractors and an improved cost estimate. (Adapted from Mims and Krepp, reference 4.)

Risk management—through the use of benchmarking, technology, training and development of a learning curve—is behind any comprehensive planning of any drilling program. However, because some measures that are appropriate when drilling conventional wells may actually increase uncertainties in ERD operations, they present engineers with unique decision-making challenges.

For example, larger-than-necessary hole sizes are often included in the upper section of vertical wells as a contingency plan to reduce drilling risk. Their inclusion allows operators to set an extra string of casing to deal with unexpected pressures, fracture gradients or wellbore instability without reducing hole size across the productive interval.

This contingency approach may be ill-advised, however, in extended-reach wells because of the effect it may have on hole-cleaning concerns such as stuck pipe. The more prudent decision may be to forgo the flexibility of larger tophole sizes to drill smaller-ID wellbores that are easier to clean of cuttings and debris. Additionally, in certain formation types, directional control may be more difficult in large-diameter holes.

A Stable Wellbore

As in all drilling operations, selection of mud weight, pump rates and drilling fluids is driven by formation-fracture gradient, pore-pressure and friction-pressure losses along the borehole-drillpipe annulus. Wellbore instability, exacerbated when the limits imposed by these parameters are exceeded, is a primary cause of drilling failures in all well types. However, the way operators deal with the problem of borehole collapse or washout differs between conventional and ERD wells.

In vertical or deviated wells, the fracture gradient of the rock typically increases with depth at a rate faster than that at which the friction-pressure losses increase. However, as an ERD well becomes essentially horizontal and depth does not change, the fracture gradient ceases to increase while ECDs continue to rise with hole length (below).

Combating the effects of rising ECDs is typically a matter of reducing mud weight, flow rate or ROP. Therefore, the better choice is often to

^ECD-limited TD. Friction pressure losses incurred as drilling fluid flows between the drillstring and wellbore are an element of ECD (red). In vertical wells, ECD increases at a slower rate than does fracture gradient (blue). However, in horizontal sections (green), the fracture gradient remains unchanged while ECD increases with wellbore length. At some point along the horizontal well path, assuming mud density, flow rate and rheology remain the same, ECD will exceed the fracture gradient, fluid loss will become unmanageable and drilling will have to be halted.
A wellbore stability study before drilling identifies zones likely to collapse, gives an estimate of the severity of the threat and recommends mud weights to manage instability. Additionally, the study identifies zones at risk for uncontrollable instability, which may require replanning. Depending on the prevailing stress state, collapse can occur on either side, the top or the bottom of the wellbore. The wellbore stability study recognizes the likely orientation of collapse, and with this information engineers can design more effective hole-cleaning procedures.

Some types of instability, such as drilling along the shale bedding plane, can create uncontrollable collapse and are especially hazardous in ERD wells. Crossing faults is also common in ERD. Engineers estimate the stresses acting on these features so that their stability can be modeled. The study considers the interaction between drilling mud and shale to prevent or minimize the impact of pore pressure increases in the shale that can lead to time-dependent degradation of the wellbore. To avoid these and other problems, experts also use a geologic model during wellbore stability modeling.

The results of the study are delivered through DrillMAP planning and management software. This tool provides a wellbore stability prediction for the specific well path, identifies the drilling hazards and recommends mud weights and operational procedures to minimize wellbore degradation (above).  


Odoptu-More is a Miocene-age hydrocarbon accumulation lying off the northeast coast of Sakhalin Island, Russia. Most, if not all, of the field can be reached from land-based surface locations (yellow ovals) using extended-reach wells (black lines). The Odoptu-More field (inset) extends roughly 4 km [2.5 mi] east to west and 12 km [7.5 mi] north to south with producing intervals at roughly 1,500 to 1,700 m [4,900 to 5,600 ft] TVD. Odoptu-More is at the northern end of a group of fields that includes Chayvo, Piltun and Arkutun-Dagi.

Wellbore debris due to instability. A review of drilling records during an investigation into one Odoptu-More well indicated that most of the trouble time related to NPT was confined to relatively short depth ranges. As hole-cleaning problems worsened, cubic meters of surplus returns—hard mudstone with a fine-grained structure and dimensions of up to 6 cm [2.4 in.] in diameter and 2 cm [0.8 in.] in height such as the one shown here—were recovered from these localized areas. The morphology of these returns did not point to a classical shear-failure mechanism generally associated with insufficient mud weight. Given their localized nature in the well and the ability to correlate these zones across part of the field, engineers theorize the likely failure mechanism is related to anisotropy within the rock itself. (Adapted from Mohammed et al, reference 11.)
Rosneft SMNG (Sakhalinmorneftegaz) was experiencing wellbore stability problems in extended-reach wells that accessed the northern part of the Odoptu-More structure off the coast of Sakhalin Island, Russia (previous page, top). The field has been drilled using extended-reach wells since 1998.

In 2003, the operator turned from drilling with positive displacement motors to using rotary steerable systems (RSSs). By 2006, 21 extended-reach wells with HD/TVD ratios of up to 4.1 had been drilled and completed.

The introduction of RSSs brought a substantial improvement in ROP. However, their use was accompanied by increased NPT stemming from hole-cleaning problems associated with backreaming through certain zones within the 12¾-in. hole section. These problems were manifested as excessive torque and drag, ECD spikes, packoffs and stuck pipe.

Using mechanical assistance—such as backreaming—in large-diameter holes is standard practice when pump- and flow-rate capabilities of the rig are limited. Not using backreaming under such conditions usually results in inefficient hole cleaning and subsequent difficulties running casing. However, in the case of Odoptu-More, these complications resulted from excessive amounts of nondrilled returns, consisting of hard mudstone debris, that were induced during backreaming operations (previous page, bottom). From analysis of multiple passes of real-time measurement-while-backreaming data, the source of the debris was eventually traced to localized rugose zones within the wellbore (above).

In response, the operator and Schlumberger engineers developed a depth-based mechanical earth model (MEM), specific to each well drilled. The team modified the casing program to more effectively isolate the key unstable zones. To complement these changes, the team also designed a customized risk-management strategy based on an understanding of the root causes of NPT in earlier wells. This strategy comprehensively addressed the formation of localized rugosity that resulted from tripping and backreaming operations. It has also proved effective in limiting the generation and associated spreading of debris from these zones.

Engineers then used the DrillMAP planning and management tool to implement a strategy based on similar methods used in the North Sea, Gulf of Mexico and South America. This plan classifies measured depth-referenced drilling risks and details control and contingency measures against the backdrop of the MEM. A new version of this protocol and a new MEM are created for each well. In addition, the team added a real-time decision-support engineering function at the rig to implement the risk-management strategy.11 As development continues on the Odoptu-More structure, continuous direction and inclination (CDNI) data are used to give early warning of cavities, and their precise location and condition are used to drive casing design.

**Push, Pull and Twist**

When planning an extended-reach well, engineers must also consider the physics of wellbore length. In vertical wells, torque, drag and buckling are essentially ignored and it is assumed the pipe is in the center of the wellbore. The loads created by these events can become so large that the pipe can no longer be rotated by the rig top-drive or moved up or down by the drawworks. The loads can also be sufficiently large that, should the pipe become stuck, efforts aimed at freeing it can cause it to part, forcing the operator to abandon the well, declare TD prematurely or drill a sidetrack well.

![Direct time-lapse evidence. In a key problem well, localized rugose zones, or caverns, could be inferred directly from inclination and azimuth anomalies seen in high-resolution, multiple-pass survey data in the 12¾-in. wellbore. These continuous deviation and inclination (CDNI) data were acquired from MWD tools run through previously drilled sections of hole. Multiple passes of CDNI data are overlaid for the inflected curves and clearly track misalignments of the surveying tool excursions of up to 1.5° from the as-drilled axis of the borehole. (Adapted from Mohammed et al, reference 11.)](image-url)

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In extended-reach wells, friction plays a more significant role than it does in vertical wells. This is because drillpipe and casing are forced against the sides of the extended-reach wellbore (above).

The occurrence and magnitude of mechanical torque, such as bit and off-bottom frictional torque, and of drag are a function of several key factors:

- tension and compression in the drillstring
- dogleg severity—rate of build, drop or azimuth change
- hole and pipe size
- drillstring weight
- inclination
- lubricity—the effect of friction reducers in drilling fluid.

Mechanical torque is created when the drillstring encounters differential sticking or interacts with cuttings beds or unstable formations. Making bit selection early in the well-planning process helps avoid bit torque, which is generated by the interaction of the bit and formation. Off-bottom torque, as the term implies, occurs when rotating the drillstring while it is raised above the bottom of the well. This eliminates the element of bit torque from the measurement. Drag is an axial force affected by the same factors as torque and occurs when the pipe is being moved up or down the wellbore.
Though all wells may experience differential sticking, extended-reach wells are particularly susceptible to the phenomenon, and recovering from it is more difficult than in conventional wells. The solution to wellbore instability at high angles is often higher mud weights that result in drilling overbalanced, which is the primary cause of stuck pipe. Also, compared with vertical wells, extended-reach wells typically leave longer sections of reservoir exposed for longer periods of time with the drillstring and BHA buried in cuttings on the low side of the hole. This may cause a packoff condition that results in stuck pipe.

Because differential sticking can greatly increase overall friction, it may intensify minor torque, drag or buckling problems. Once differential sticking does occur in an extended-reach well, the driller’s ability to get the pipe free is reduced by the high wellbore angle, which limits how much weight or tension may be transmitted to the BHA. Typically, in a conventional well, pipe may be considered permanently stuck when 667,000 N (150,000 lbf) of overpull fails to move it. In an extended-reach well, the inability to transmit weight or tension may drive that value to as low as 89,000 N (20,000 lbf). The problem is made worse in the presence of high drag forces since it may be impossible to exert enough upward force to set and activate the drilling jars.

Because extended-reach wells are so susceptible to the effects of friction, planning engineers must simulate all major operations to ensure that each is feasible and that loads are within acceptable limits. This requires use of torque and drag modeling programs.

Torque and drag models use a nondimensional friction factor that accounts for a number of elements impacting pipe movement, including:

- mud system lubricity
- pipe stiffness
- cuttings beds
- stabilizer and centralizer interaction
- differential sticking
- hydraulic piston effects
- key seats.

Pipe stiffness attempts to account for additional side forces on the pipe rather than a “soft pipe” model, which assumes the tubular conforms to the well profile. Stabilizers and centralizers are mechanical devices attached to the drillstring or casing to keep them located in the center of the hole. Hydraulic piston effects are caused by moving the pipe through fluids in the wellbore in a manner to create pressure surges. Key seats occur when the drillpipe wears a groove in one side of the hole in a build, drop or turn section. The larger-diameter BHA cannot be pulled back through this groove and so becomes seated when operators attempt to move the drillstring up the hole.

Small variations in friction factors can significantly impact torque and drag calculations. Changes to parameters such as mud weight, well path, casing point selection and drillstring or casing design may cause these variations during drilling. It is critical, therefore, that while planning an extended-reach well, a suitable range of friction factors be considered. Engineers use torque and drag risk analyses to determine possible outcomes when the friction factor varies (above).

Analyzing risk of drag. Minor variations in friction factors can have major impact on torque and drag in extended-reach wells. During the planning stage, it is essential that friction factors be analyzed for sensitivity to variations in mud weight, well path, hole profiles or drillstring configuration. This example is for a 9%-in. float-casing run in a well with an expected openhole friction factor of 0.50. The slack-off surface tension is equivalent to the expected reading on a weight gauge at the surface as the casing is being lowered into the well. The red curves represent several friction factors ranging from 0.30 to 0.70. In this case if the friction factor is only slightly greater than 0.50, the casing weight will become negative, which means that the combination of friction and the casing buoyancy in the wellbore fluids will be greater than the casing weight, preventing the casing from reaching bottom. Floated casing is a technique in which the drilling fluid is replaced by air in that part of the casing in the tangent section. This increases casing buoyancy, which reduces torque and drag by lessening the contact force between it and the borehole wall. While this eliminates the option to circulate, it may lighten the casing sufficiently for it to be rotated, which may counter the effects of torque and drag.
Buckling may also become a significant challenge in drilling extended-reach wells. Buckling, a poorly understood phenomenon, is the result of cumulative drag that applies compressional forces on the drillstring or casing and causes the string to change its behavior. Buckling also occurs in BHAs but, especially since the advent of RSSs, the ability to manage it has improved.

As with all ERD problems the potential for buckling must be considered during well planning. When selecting tubulars, planning turn and build rates and designing annular clearances in the lower sections of the hole, engineers must be particularly aware of the potential for buckling.

Other proactive steps to help avoid buckling include maintaining a stiff drillstring while avoiding the addition of weight that can exacerbate torque and drag problems. Because pipe stiffness is a function of its radius, larger diameter drillpipe has been used in extended-reach wells to eliminate the limiting factor. From a review of the Al-Shaheen field, MOQ concluded that the length of horizontal sections in the field was limited by the torque capacity of the drillpipe connections and ECD loads rather than topdrive or rig capability (top). To set its record length at the BD-04A well, the operator used 5-in. drillpipe with high-torque connections. At 23,600 ft, a section of 4-in. drillpipe was added above the BHA. Then, at 28,000 ft, the lubricant additive in the drilling mud was increased from 2% to 3%. As a result, drilling torque was reduced from a projected average (not shown) as high as 26,000 ft.lbf [35,000 N.m] to a measured average ranging from 14,000 to 21,000 ft.lbf [19,000 to 28,000 N.m]. Friction factors of 0.20 to 0.24 were reduced to 0.18 to 0.21. At the same time the increased flow area created by the section of smaller diameter drillpipe above the BHA reduced ECD from 15.2 to 14.3 lbm/galUS [1,797 to 1,714 kg/m³] (bottom). (Adapted from Sonowal et al, reference 2.)

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Other proactive steps to help avoid buckling include maintaining a stiff drillstring while avoiding the addition of weight that can exacerbate torque and drag problems. Because pipe stiffness is a function of its radius, larger diameter drillpipe has been used in extended-reach wells to eliminate the limiting factor. From a review of the Al-Shaheen field, MOQ concluded that the length of horizontal sections in the field was limited by the torque capacity of the drillpipe connections and ECD loads rather than topdrive or rig capability (top). To set its record length at the BD-04A well, the operator used 5-in. drillpipe with high-torque connections. At 23,600 ft, a section of 4-in. drillpipe was added above the BHA. Then, at 28,000 ft, the lubricant additive in the drilling mud was increased from 2% to 3%. As a result, drilling torque was reduced from a projected average (not shown) as high as 26,000 ft.lbf [35,000 N.m] to a measured average ranging from 14,000 to 21,000 ft.lbf [19,000 to 28,000 N.m]. Friction factors of 0.20 to 0.24 were reduced to 0.18 to 0.21. At the same time the increased flow area created by the section of smaller diameter drillpipe above the BHA reduced ECD from 15.2 to 14.3 lbm/galUS [1,797 to 1,714 kg/m³] (bottom). (Adapted from Sonowal et al, reference 2.)

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fight buckling. It is important, however, to consider the impact of the resulting frictional pressure losses on ECD. Other measures are available, including special downhole tools that reduce torque and drag forces or that better facilitate load transfer.

A Model Solution
The Al-Shaheen field, Block 5 offshore Qatar, has a history of poor productivity from vertical wells, and development using conventional wells would require a large number of platforms. Additionally, the field’s hydrocarbon reserves are areally extensive. These factors make the field a particularly good prospect for an ERD strategy, but the operator, Maersk Oil Qatar AS (MOQ), had to first overcome torque and ECD problems that threatened to limit horizontal-reach lengths.

MOQ targeted the Lower Cretaceous Kharai B and Shuaiba carbonate formations and the Nahr Umr sandstone. The Kharai B Formation is a laterally uniform carbonate layer about 80 ft [24 m] thick with a 25 ft [8 m] thick reservoir target. The Shuaiba Formation includes lateral facies changes and permeability contrasts. It is about 200 ft [60 m] thick with a reservoir target about 20 ft [6 m] thick. The Nahr Umr Formation is a 20-ft sequence with reservoir targets made up of permeable sands with a thickness of 5 ft [1.5 m] or less.

In 1994, the operator drilled a record-breaking 1.9-mi [3.1-km] horizontal section using positive displacement motors and adjustable gauge stabilizers. By adopting new technology as it became available, the company improved on that achievement. In May 2008, MOQ completed a record horizontal reach of 6.8 mi [10.9 km], with a measured depth of 7.6 mi [12.3 km] and, at the time, the world’s longest along-hole departure of 37,956 ft or 7.2 mi [11.6 km].

The original measured depth of the well was to be 5.5 mi [8.8 km] but the operator chose to extend that to appraise the eastern flank and increase the exposure of the reservoir using a single wellbore. However, torque and drag modeling indicated loads at the new TD would exceed the topdrive and the drillstring capabilities. At the same time, ECDs would be unacceptably high using the existing 5-in. drillpipe and traditional mud properties.

Modeling indicated that these ECDs and torque loads could be brought to acceptable levels using a tapered 4- by 5-in. drillstring. The model also determined that a tapered string would result in higher pump pressure and reduced flow rate at TD and that the length of the 4-in. section was the limiting factor in balancing the conflict. The final design reconciling torque and drag, hydraulics and ECD models included 7,000 ft [2,133 m] of 4-in. drillpipe and 15,000 ft [4,572 m] of 5-in. drillpipe with high-torque connections added to the top of the drillstring (previous page).

The 8 1/2-in. section of the well was drilled in two runs. The first used a PowerDrive Xceed point-the-bit RSS to reach 33,877 ft [10,236 m] with drilling torque monitoring that indicated a friction factor of between 0.18 and 0.21. During that first run, lubricant additive levels were increased from 2% to 3% to reduce torque and the severity of stick/slip and thus reduce vibration, allowing the driller to maintain ROP without damaging the BHA. Drilling torque peaked at the topdrive limit of 36,000 to 39,000 ft.lbf [49,000 to 53,000 N.m]. The operator then picked up 4-in. drillpipe to reduce torque and ECD loads.

The second run—using a 4- by 5-in. tapered drillstring—immediately resulted in sufficient torque and ECD improvements to allow drilling to a final TD of 40,320 ft [12,290 m] MD. This included a 35° azimuth turn. Additionally a PowerDrive Xceed point-the-bit RSS was used because it requires a smaller pressure drop across the tool than the push-the-bit design. A larger bit-nozzle flow area was also included in the calculus to improve pump pressure and flow rate at the bit.

The operator was able to achieve this record length by placing emphasis on ECD management and taking steps to control friction-factor increases during the planning phase of the well. Simulations indicated that if ECD-induced lost-circulation rates remained acceptable, the well could have been drilled to about 44,000 ft [13,400 m], at which point it would have reached the torque limit of the topdrive.

Drilling Ahead
Originally, constructing long horizontal wells was an economic decision—either more pay zone exposed for the cost of one wellbore or numerous formations tapped for the cost of a single surface location. By acting as extremely deep-penetrating, large-diameter perforation tunnels, horizontal wells are also an answer to the challenge of achieving economic flow rates from tight, thin formations.

But as the industry has learned to drill wells beyond the limits once imposed by torque, drag, ECD and rig capacities, ERD has become attractive for reasons other than economic ones. As was demonstrated at the Wytech Farm field in England, long horizontal wells also offer environmentally acceptable alternatives. The formations targeted by those wells lie beneath the ecologically sensitive Poole Harbour. By placing surface locations on land some distance from the shoreline and drilling far beneath the harbor floor, the waterway and its immediate surroundings remained isolated from operator activity. This drilling choice allowed the area to remain visually appealing and reduced the threat of ecological contamination.

Today the world finds itself in something of a dilemma. People have become keenly aware of the fragility of the Earth’s environment at the same time that globalization has raised the standard of living for millions. But that prosperity has come at the cost of creating an insatiable demand for hydrocarbon-base fuels, which requires more drilling. Applying ERD practices to access more deposits while drilling fewer wells from fewer surface locations is one measure the upstream industry is using to help reconcile these competing realities.

—RvF