Extended-Reach Drilling: Breaking the 10-km Barrier

Geosteering, torque reduction and casing flotation have all contributed to record-breaking extended-reach drilling achievements. The limits of directional drilling continue to be pushed back as horizontal reservoir sections greater than 2500 m are being drilled, cased, cemented and completed to tap reserves at extreme distances from surface wellsites.

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Wytch farm extended-reach drilling. Logging-while-drilling and GeoSteering tools provided real-time data for the geologist to adjust the well path and guide the well along an optimum route through the thin pay zones at Wytch Farm, southern England. In long extended-reach wells, geosteering techniques are instrumental in maintaining a smooth, accurate wellbore through the reservoir.

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Extended-reach drilling technology recently achieved a new milestone with the drilling and completion of a 10-km [33,000-ft] stepout well, some 2 km [6600 ft] longer than the previous world record. The main technical hurdles to the success of this well were reducing torque and drag, controlling fluid circulation and maintaining directional control. Solutions were not simple because methods to mitigate technical challenges in one area often had adverse consequences in others. One factor, drillstring rotation, repeatedly surfaced as part of the solution to all the major problems in this extended-reach well.

Guiding a wellbore accurately through the pay zone at such extreme distances would be virtually impossible without geosteering (*previous page*). Geosteering involves taking petrophysical measurements at or near the bit and relaying the information in real time to the drilling team. The team can then adjust the bit direction to aim the wellbore optimally through the formation. The result is that smaller targets at greater distances can be drilled successfully. Geosteering has been a success in terms of both the technical practicalities and the productivity benefits in extended-reach wells.

This record extended-reach well, M-11, at the BP Exploration Operating Co. Ltd. Wytch Farm development in southern England, has a horizontal displacement of 10,114 m [33,182 ft] at a true vertical depth (TVD) of only 1605 m [5266 ft]. Well M-11 is the second extended-reach record well at Wytch Farm (*above*). Both wells used Anadrill logging-while-drilling (LWD), measurements-while-drilling (MWD) and GeoSteering tools. The M-05 well had set a displacement record of 8035 m [26,361 ft] in 1995 (*right*).

The M-05 record was broken last year by Phillips China, Inc., which drilled the Xijiang 24-3 in the South China Sea to a horizontal displacement of 8063 m [26,446 ft].[1] Horizontal displacement, also called stepout or departure, is the farthest horizontal distance from a vertical line below the surface location to the tip of the well.

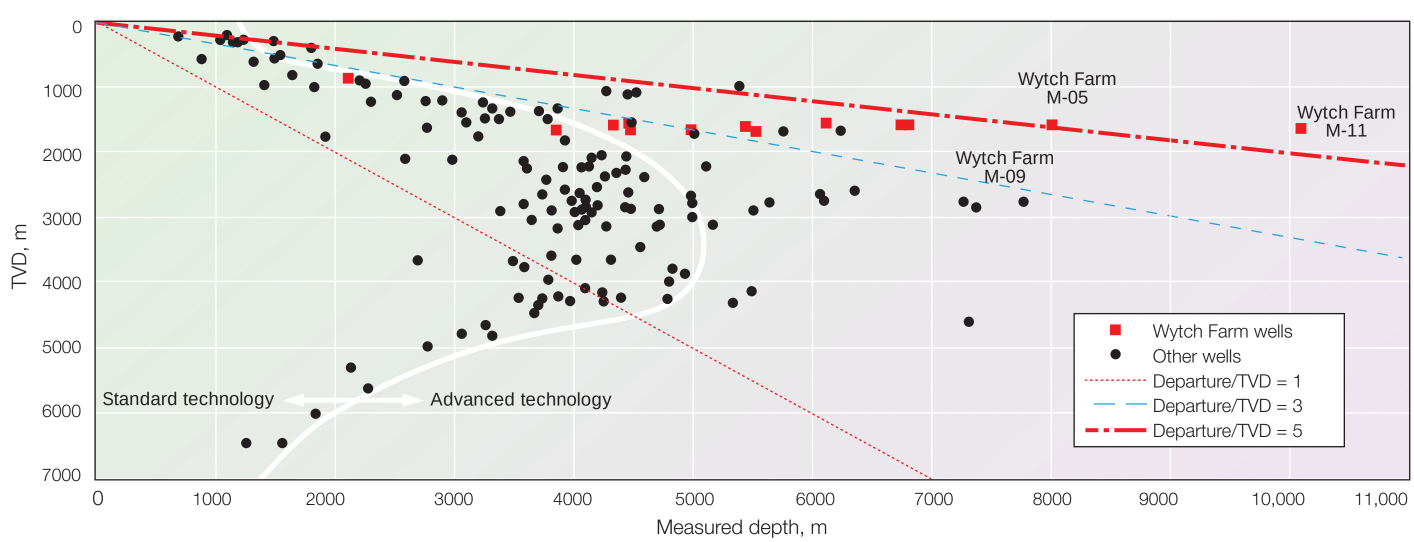
The total measured depth of Well M-11 is 10,658 m [34,967 ft], a remarkable achievement that puts this well second among the longest wellbore paths drilled in the world. In comparison, the world's deepest well at 12,869 m [42,226 ft] measured depth is a vertical well, SG-3, drilled by the Ministry of Geology of the former Soviet Union for scientific exploration on the Kola Peninsula.[2]

The stepout ratio (horizontal displacement divided by TVD at total depth) is 6.3 for Well M-11 (*below*). Generally, a well is defined as extended reach if it has a stepout ratio of 1 or more. A horizontal well is loosely defined as having a final segment at an 85° to 90° inclination from true vertical. An extended-reach well may also be a horizontal well, but this is not a requirement.

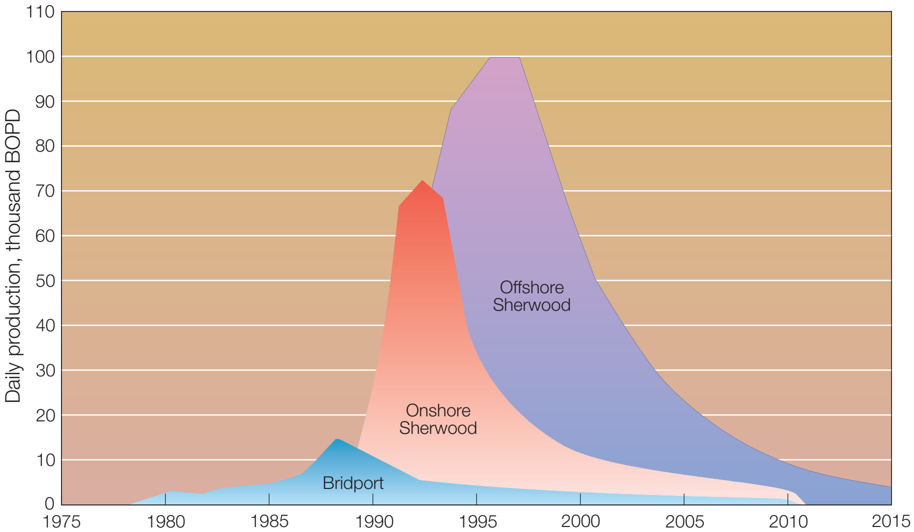
Rank	Horizontal displacement, ft	Measured depth, ft	TVD, ft	Operator	Well	Location
1*	33,182	34,967	5266	BP	M-11	UK, Wytch Farm
2*	26,446	30,308	9554	Phillips	Xijiang 24-3	South China Sea
3*	26,361	28,593	5285	BP	M-05	UK, Wytch Farm
4	25,764	30,600	NA	Norsk Hydro	30/6 C-26	North Sea
5*	25,108	27,241	NA	BP	M-09	UK, Wytch Farm
6*	23,917	28,743	9147	Statoil	33/9 C-2	North Sea
7*	22,369	24,442	NA	BP	M-03	UK, Wytch Farm
8*	22,180	24,680	5243	BP	M-02	UK, Wytch Farm
9	21,490	26,509	NA	Norsk Hydro	30/6 B-34	North Sea
10*	21,289	25,991	NA	Norsk Hydro	30/6 C-17	North Sea
11	20,966	24,670	9076	Amoco	SEER T-12	North Sea
12*	20,577	21,102	NA	Norsk Hydro	31/4 A-8A	North Sea
13*	20,577	25,010	NA	Norsk Hydro	30/9 B-30	North Sea
14*	20,514	22,907	5528	Total Austral	ARA S7/1	Tierra del Fuego, Arg.
15	20,289	25,164	NA	Norsk Hydro	30/6 B-6	North Sea
16*	20,151	25,541	NA	Norsk Hydro	30/6 C-24A	North Sea
17*	19,667	22,559	5324	BP	M-06	UK, Wytch Farm
18	19,209	23,786	8845	Statoil	33/9 C-3	North Sea
19*	19,030	23,835	NA	Norsk Hydro	30/9 B-48	North Sea
20*	18,758	24,540	13,940	BP	2/1 A-13	North Sea

* Directional drilling, MWD, LWD or GeoSteering services provided by Anadrill

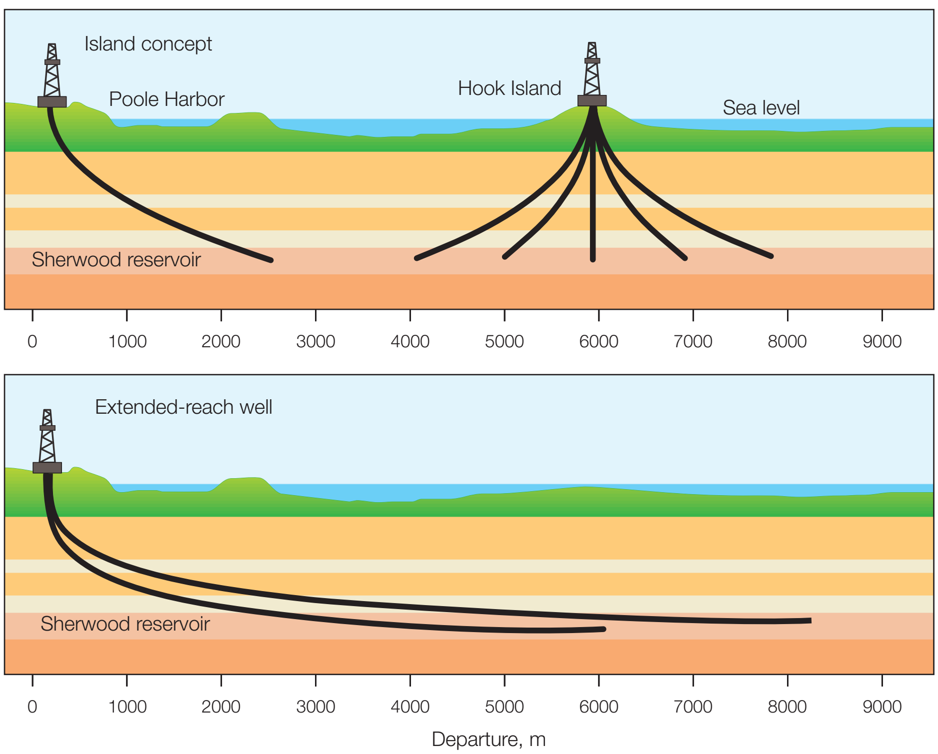
Top 20 extended-reach wells worldwide.



Industry comparison of extended-reach wells. What was once considered the envelope of extended-reach drilling now merely indicates the difference between standard and advanced technology. That envelope continuously enlarges as companies push technology to the limit.



□*Daily production forecast. The third-stage development of Wytch Farm comprises extended-reach wells drilled from two onshore sites to produce reserves that sit offshore. More than 80% of the current field production comes from extended-reach wells. The extended-reach program increased reserves from 300 million bbl before the program to 467 million bbl now.*



□*Artificial island development concept. The original proposal for development of the offshore reserves called for construction of an artificial island and simple directional wells. Instead, extended-reach wells were chosen because there would be less impact on the environment and development would cost less than half and occur three years earlier.*

Wytch Farm Development

Drilling the "10-km challenge," as Well M-11 had been nicknamed throughout planning and operations, was driven by environmental and economic as well as technical objectives. Simply put, the well was drilled because it economically tapped additional reserves more than 10 km from the surface wellsite. These reserves lay in a section of the Sherwood reservoir which extends offshore beneath Poole Bay on the southern coast of England. Wytch Farm is western Europe's largest onshore oil field, but roughly one-half of its 467 million bbl [74 million m^3]of oil extends offshore. The Wytch Farm oil field comprises three major reservoirs, the shallower Frome Limestone at 800 m [2625 ft], the Bridport reservoir at 900 m [2900 ft] and the larger, more productive Sherwood reservoir at 1600 m [5200 ft]. The Bridport has been on production since 1979 and was the first stage of Wytch Farm development. The second stage consisted of the onshore Sherwood reserves, and third stage the offshore Sherwood (*above left*).

In 1990, BP began analyzing methods of producing offshore reserves from the Sherwood reservoir, including evaluation of setting a platform or constructing an artificial island (*left*). The field sits near a nature preserve and is in an area of outstanding natural beauty frequented by tourists. Thus, any development plan had to be aesthetically pleasing with minimal effect on the area. The development plan also had to adhere to stringent environmental regulations. The initial plan called for construction of an artificial island with conventional directional wells at a cost of £180 million [$330 million].[3] In contrast, development of the offshore reserves with extended-reach wells would cost less than half as much at an estimated £80 million [$150 million] and would better protect the environment. Furthermore, the use of extended-reach wells accelerated production by three years.

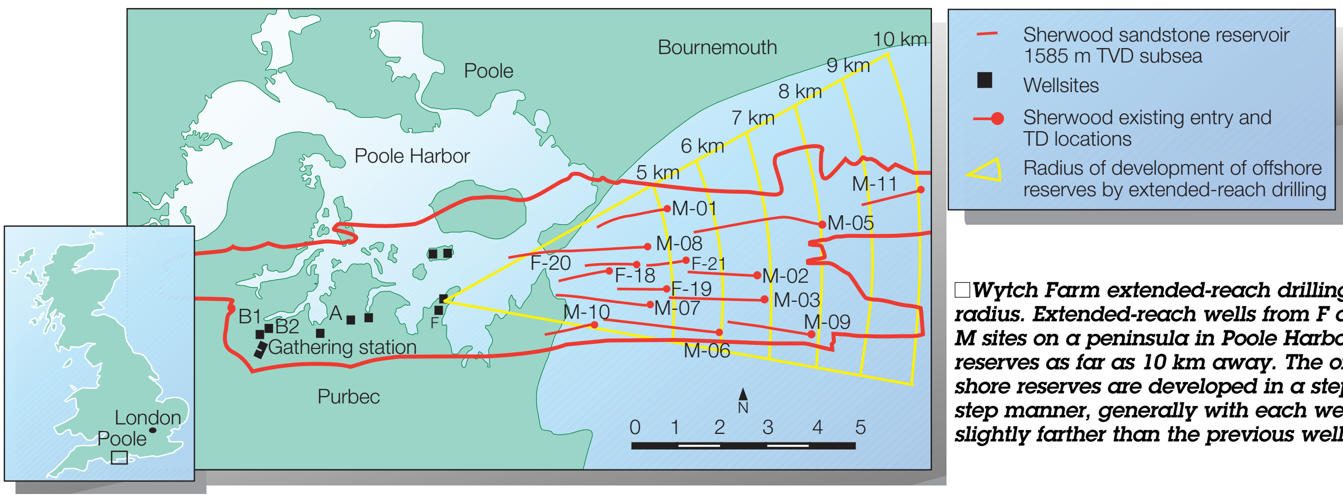
1. Talkington K: "Remote South China Sea Reservoir Prompts Extended Reach Record," *Oil & Gas Journal* 95, no. 45 (November 10, 1997): 67-71.
2. Petzet GA: "Unreal 'Depth' at Wytch Farm," *Oil & Gas Journal* 96, no. 7 (February 16, 1998): 17.
3. "BP Taps Wytch Farm with Extended Reach Wells," *Oil & Gas Journal* 92, no. 1 (January 3, 1994): 30-31.

Well M-11 is the fourteenth extended-reach well drilled in the third stage of Wytch Farm development (*below*).[4]

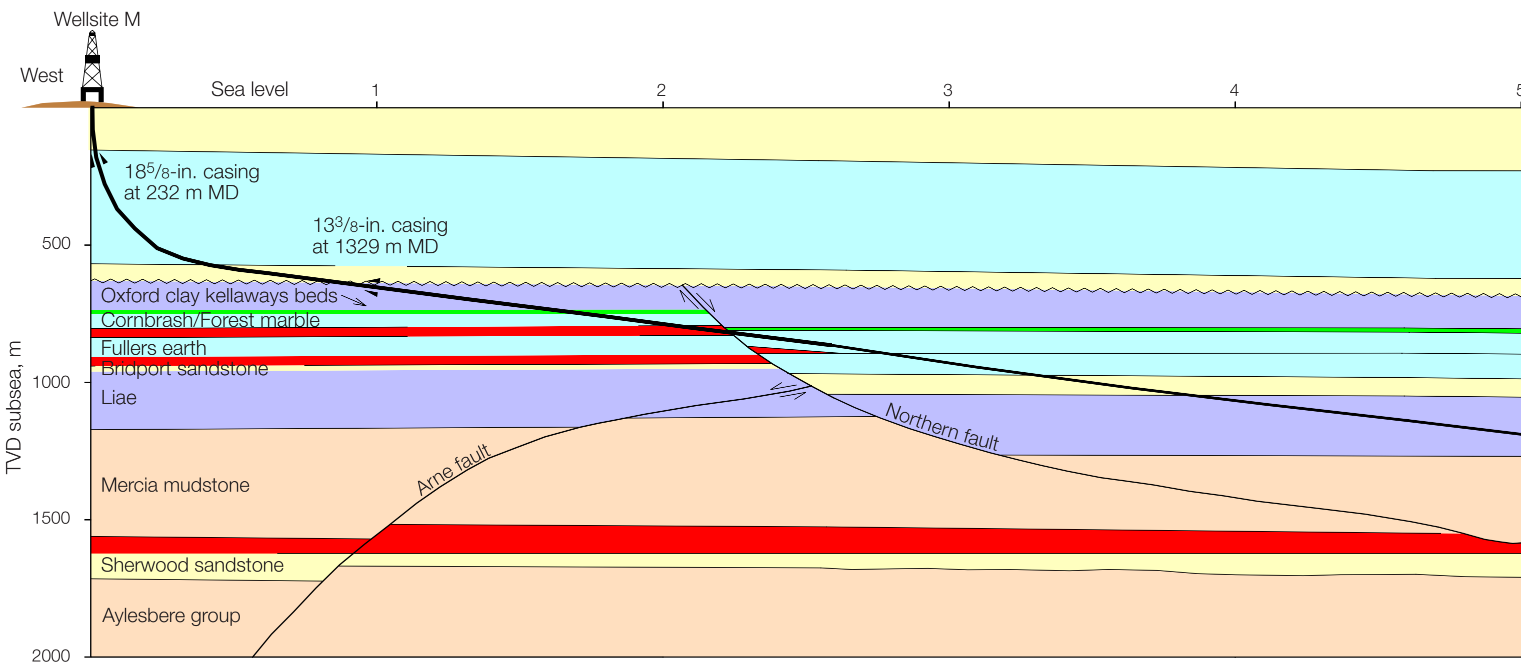
A significant factor in the decision to use extended-reach drilling (ERD) was the success of other companies, particularly Unocal Corp. in the Point Pedernales field in southern California, USA.[5] In the late 1980s, collapsing oil prices prompted Unocal to design and drill extended-reach wells from an existing platform rather than set a second platform. For Unocal, extended-reach wells achieved several objectives: they eliminated the high capital cost of a second platform, intersected more of the formation with near-horizontal wellbores and demonstrated conclusively that such difficult wells could be drilled and completed economically. These wells were relevant to Wytch Farm because of the shallow TVD of 1350 m [4420 ft]. Many other wells had been drilled with long stepouts, but none at such shallow depths. The base requirement for further field development was the capability to drill and complete wells at up to 6000-m [20,000-ft] departure from onshore wellsites, which BP felt to be a reasonable extension of existing technology.[6]

The use of extended-reach wells results in less surface disturbance because fewer wells are needed and surface sites have a smaller footprint. In developing Wytch Farm field, BP sought to maximize oil recovery as economically as possible with the least disturbance to the environment and the surrounding community. Drilling from small surface sites instead of an offshore location helped accomplish this goal. BP established a partnership with local communities and regulatory authorities to ensure that the natural beauty of the Poole area remained unspoiled. More than 300 formal meetings and countless informal discussions were held with local authorities, government departments, environmental and conservation organizations and the general public to ensure that the views of area residents be considered in the development of the field.

The area around the oil field forms part of the Dorset Heritage Coastline and includes areas of special scientific interest, a wildlife special protection area, a wetland birds site and a national nature reserve. The surface site is designed to blend into the



Wytch Farm extended-reach drilling radius. Extended-reach wells from F and M sites on a peninsula in Poole Harbor tap reserves as far as 10 km away. The offshore reserves are developed in a step-by-step manner, generally with each well slightly farther than the previous wells.



Geological cross section. The world's longest extended-reach well has a stepout of 10,114 m and a total measured depth of 10,658 m.

environment, and equipment is painted in earth-tone colors to minimize visual impact. All lighting is judiciously placed and pointed downward. Strict noise regulations are imposed and ensure minimal disturbance. An extensive impermeable containment ditch surrounding the site can hold any fluids from potential accidents.

Teamwork and Planning

An extended-reach well requires extensive planning and involves the commitment and direct participation of the operator, rig contractor and all service providers. The evaluation, design and planning of Well M-11 lasted more than a year, from March 1996 until drilling began in May 1997.

Close cooperation and a smooth working relationship were essential for such a challenging, high-profile project as Wytch Farm. Contractors were paid on a day-rate basis with total well performance incentives to be shared among all participants, further encouraging teamwork and ensuring alignment of goals. Anadrill supplied directional well planning and drilling engineering support, directional drillers and equipment, surveying, MWD/LWD, mud logging and coring services. Baroid provided mud supplies, mud engineering, and drill-cuttings and waste fluids disposal. BJ Services provided cementing services. Deutag Drilling supplied the drilling rig, crews, drillstring tubulars, tubular running services and fishing tools. Lasalle designed, installed and commissioned completion and electrical submersible pump equipment. Schlumberger Wireline & Testing supplied openhole logging services, cased-hole logging services, drillstem test and tubing-conveyed perforating and well testing; and Dowell supplied coiled tubing services.

The focus during the early part of the third stage of development was to build multidisciplinary teams, with contractors working in close proximity to the operator's staff. Contractor senior representatives have offices close to one another within the operator's office complex in Poole. This setup fosters a close but informal "roundtable" arrangement. Communication barriers have disappeared, and everyone on the project has the same goals—to drill the wells efficiently, correctly and economically. Decisions are made and involve both the operator and contractors. For such a system to work effectively, a high degree of trust and openness is necessary among personnel of all rank. This working environment has provided the opportunity to obtain excellent benchmark data for drilling subsequent extended-reach wells, leading to the record-setting 10-km target.

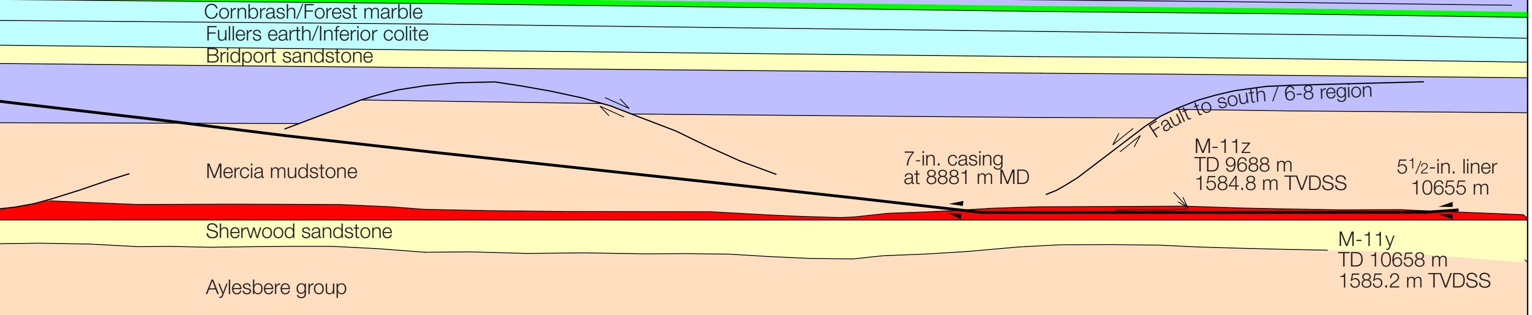
At the onset of third-stage development, two of the least known factors were the increased time and cost for extended-reach compared to conventional wells. Typically, the first one or two wells of any project incur the greatest time and cost as the learning curve begins. Efficiency and performance improve rapidly on subsequent wells as team members work together more efficiently, and technology is applied more effectively. Generally, each well at Wytch Farm has been drilled farther than the previous wells, allowing for incremental learning through experience. Had such an incremental learning process not been used, many problems would undoubtedly have occurred on the M-11 well.

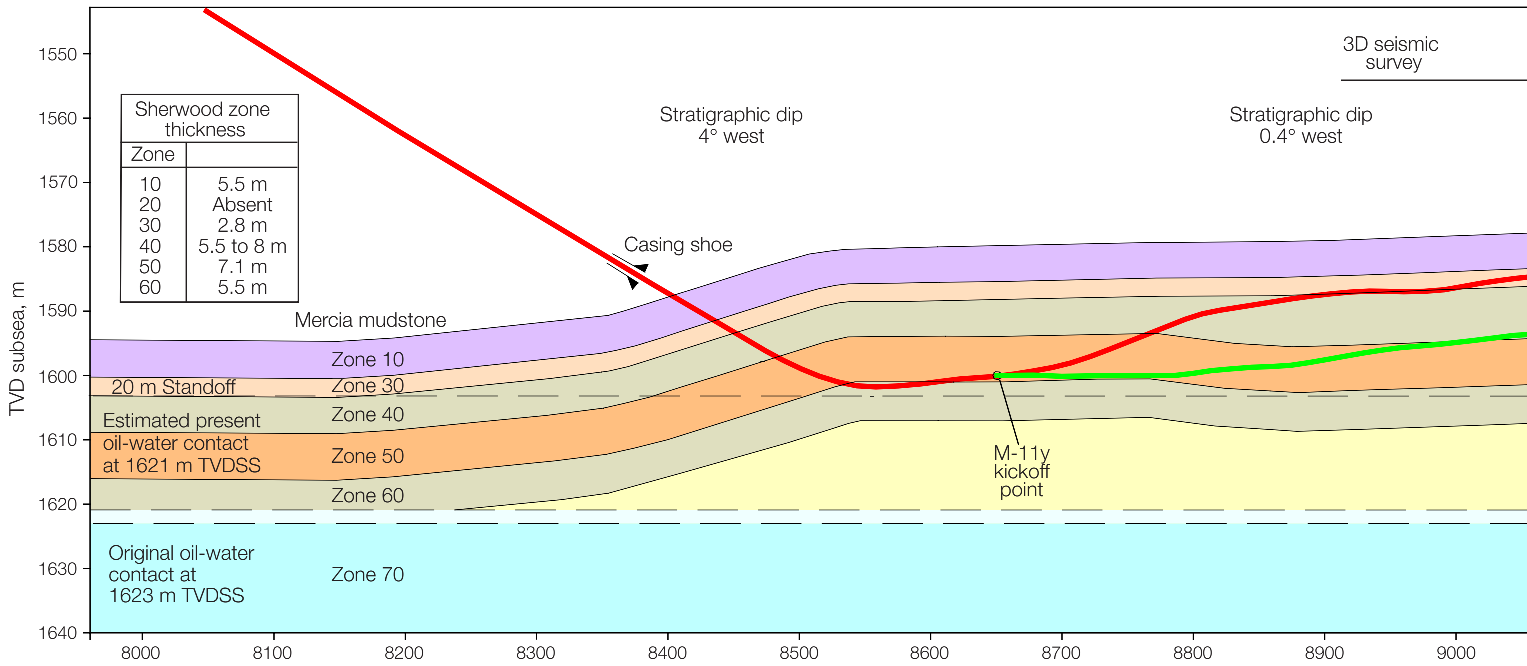
Every aspect of the M-11 well plan underwent a rigorous peer review to identify potential pitfalls and develop contingency plans. Experts from BP and its partners thoroughly analyzed key risks and processes in reservoir issues, well placement, drilling mechanics, hydraulics and safety. Having outsiders analyze the well plan provided a useful check against existing contingency plans.

Profile Design

The reservoir section targeted by Well M-11 lies between 8- and 10-km [26,000- to 33,000-ft] departure from the M site (*previous page, bottom and below*). For this length departure, the relatively shallow depth of the Sherwood reservoir posed some special drilling challenges not present at greater depths. There was limited scope in the trajectory design to allow the target to be

4. Knott D: "BP Completes Record Extended-Reach Well," *Oil & Gas Journal* 96, no. 3 (January 19, 1998): 24-26.
5. Mueller MD, Quintana JM and Bunyak MJ: "Extended-Reach Drilling from Platform Irene," paper SPE 20818, presented at the Offshore Technology Conference, Houston, Texas, USA, May 7-10, 1990.
6. Banks SM, Hogg TW and Thorogood JL: "Increasing Extended-Reach Capabilities Through Wellbore Profile Optimization," paper IADC/SPE 23850, presented at the IADC/SPE Drilling Conference, New Orleans, Louisiana, USA, February 18-21, 1992.





reached optimally.[7] The majority of wells at Wytch Farm have been drilled with 80° to 82° tangent angles and were controlled by choice of kickoff point and build rate in the upper section.

This well was planned to have a shallow kickoff point to allow inclination angle to be built to 82° in the 17½-in. hole. The 13⅜-in. casing was to have been run to about 1400 m [4600 ft] measured depth, and then the 12¼-in. hole was to be drilled as a 7500-m [24,600-ft] tangent section into the top of the Sherwood reservoir. The length of the 8½-in. hole section was kept to a minimum because reservoir drilling is three to four times more expensive than in the 12¼-in. section due to extra bottomhole assembly equipment, mud losses and slower penetration rates. In addition, the mudstone above the reservoir would be exposed to a low-weight mud, leading to concerns about borehole stability.

A tangent angle of 82° was used to keep torque levels manageable, maximize the likelihood of being able to run casing to a 10-km departure and permit oriented drilling in the 8½-in. section (*above and next page, top*). The final double build and hold trajectory was similar to that on other wells, except that steering would be further limited in the 8½-in. section. This trajectory would allow the well to build angle to horizontal starting at the 9⅝-in. casing shoe. Previous wells used an instrumented positive displacement motor, LWD tools and an adjustable stabilizer to geosteer in the reservoir.

Because steering capability would be limited, Well M-11 was designed to be drilled as geometrically as possible through the reservoir, with some geosteering performed by rotary steering drilling tools.

The key to success would be performing every phase of the well plan flawlessly. Directional control, hole cleaning, torque and drag, and casing flotation each played a role. The rest of this article describes how they come together in the drilling of this record-setting 10-km well.

Directional Control

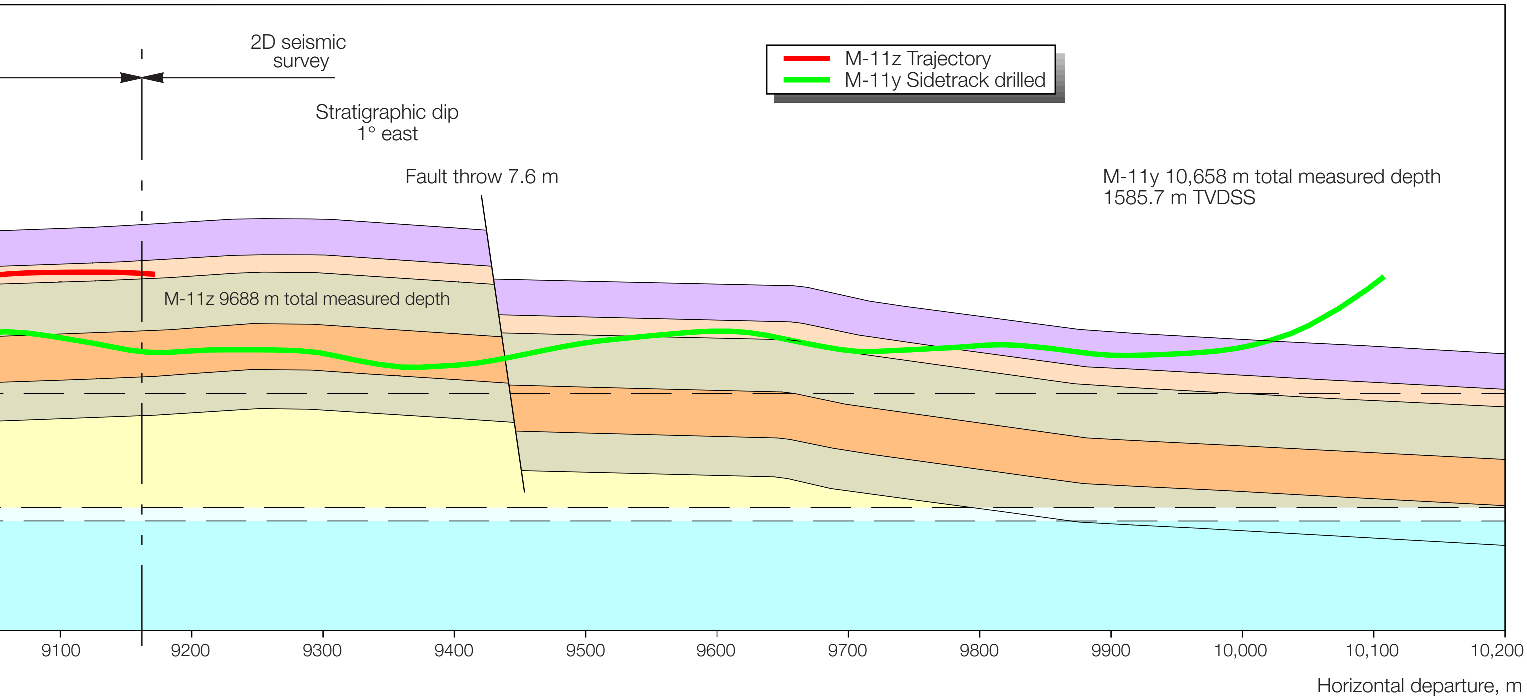
Steering by slide drilling is impossible at extreme horizontal distances. Experience on Wells M-05 and M-09 indicated that slide drilling would be practically impossible beyond 8 km. Drilling in the sliding mode results in several inefficiencies that are compounded by extreme distances. The motor must be oriented and maintained in a particular direction while drilling to follow the desired path. This orientation is achieved through a combination of rotating the drillstring several revolutions and working the pipe to turn it to the desired direction. At 8 km or more, the pipe may need 15 to 20 turns at surface just to turn the tool once downhole, because the drillstring can absorb the torque over such a long distance. For the directional driller, this technique is as much art as it is science. After the tool is positioned, drillstring torque is required to hold the motor in proper orientation against reverse torque created by the motor as the bit drills.[8]

This situation is beneficial in wells with low frictional drag because adjusting weight on bit changes reactive torque, changing toolface direction. Thus, small changes in orientation can be made by varying weight on bit, giving the directional driller better control. In high-drag situations like Well M-11, however, it is difficult to keep torque constant in the lower part of the drillstring, causing difficulty in maintaining toolface orientation. Another problem with slide drilling in high-angle wells is that cuttings removal suffers from the lack of drillstring rotation. In wells with high drag, the drillstring cannot be lowered smoothly and continuously, which prevents the motor from operating at optimal conditions. In combination, these factors result in a lower penetration rate compared to that during rotary drilling (*next page, bottom*). For extended-reach wells, not only does penetration rate suffer, but there is a point at which slide drilling is no longer possible.

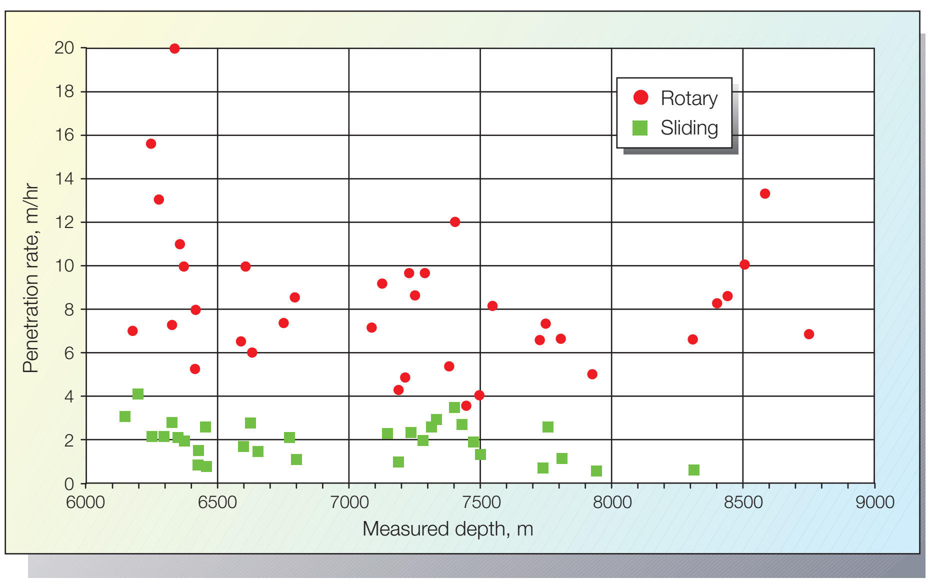
The M-11 trajectory was designed to minimize the amount of sliding directional work in the 8½-in. reservoir section. In some of the earlier Wytch Farm wells, a new technique was pioneered to overcome these

7. Modi S, Mason CJ, Tooms PJ and Conran G: "Meeting the 10km Drilling Challenge," paper SPE 38583, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, October 5-7, 1997.

8. Warren TM: "Trends Toward Rotary Steerable Directional Systems," *World Oil* 218, no. 5 (May 1997): 43-47.



Sidetrack cross section. When the original borehole (M-11z) reached 9 km, the well was sidetracked to access a better part of the reservoir. The sidetracked lower bore (M-11y) was cased and completed, and the upper borehole left open. The tip of the well veers upward to stay away from the oil-water contact and to penetrate additional formation layers for added geological information.



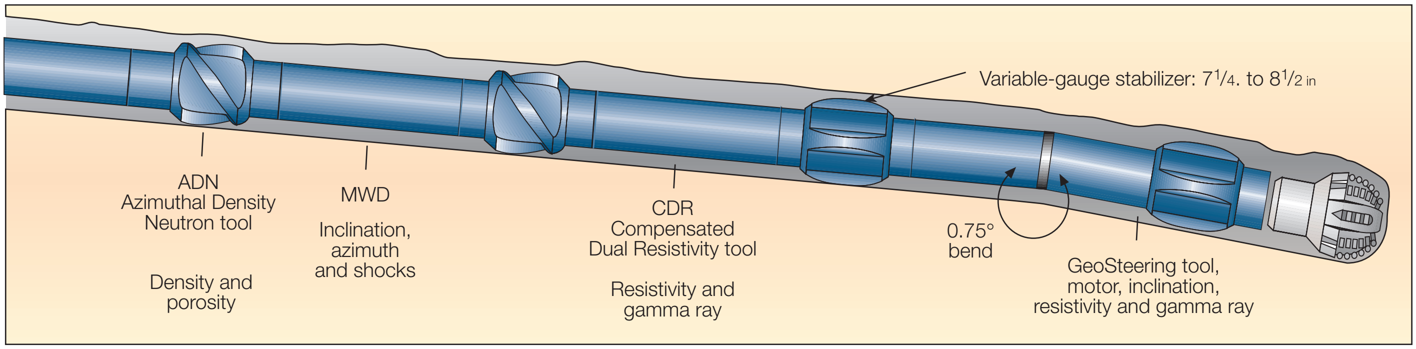
Rotary and sliding penetration rates. In offset Well M-05, rotary drilling penetration rates were several times greater than slide-drilling penetration rates. Conventional slide drilling techniques were ineffective at extreme stepout distances because of difficulty controlling downhole torque and weight on bit.

problems with conventional sliding for directional control.[9] The combination of the GeoSteering tool near-bit inclination measurement and a downhole variable-gauge stabilizer positioned above the motor enabled drilling the wells almost entirely in rotary mode.

Standard steerable-motor directional drilling equipment is generally based on the tilt-angle principle. A bend between 0.5° and 3° in the motor provides the bit offset necessary to initiate and maintain changes in course direction. Three geometric contact points (bit, near-bit stabilizer on the motor and a stabilizer above the motor) approximate an arc that the well path will follow, and thus the curve rate or dogleg severity for the system. This curvature is formed and built by holding the entire drillstring still so that the bend can work in a preferential direction or in sliding mode.[10]

Conventional practice is to drill in rotary mode, rotating the drillstring from the surface to drill a straight path. If a change in direction is needed, the drillstring is stopped with the bent housing or tilt on the steerable system oriented in the desired direction. This orientation is called the toolface angle and is measured downhole by MWD systems. When drilling in this oriented mode, the entire drillstring has to slide. Drillstring drag problems become acute in extended-reach wells and cause problems in setting the toolface angle and applying weight to the bit. Rate of penetration suffers. Techniques are needed to provide greater directional flexibility with rotary drilling in extended-reach wells.

□ ***The art and science of directional drilling. The directional driller closely monitors surface and downhole measurments of torque, drag and direction. It takes a skillful directional driller to interpret these data and then steer the bit accordingly by tweaking the downhole tools from surface. The result is a smooth wellbore right on target.***



GeoSteering assembly. The Anadrill GeoSteering tool was used to drill the 8 1/2-in. reservoir sections of early Wytch Farm wells and to drill out past the 9 5/8-in. casing shoe of Well M-11. This BHA configuration included a variable-gauge stabilizer to steer the well. Mud pulses adjust the stabilizer blades in or out to alter the inclination of the assembly.

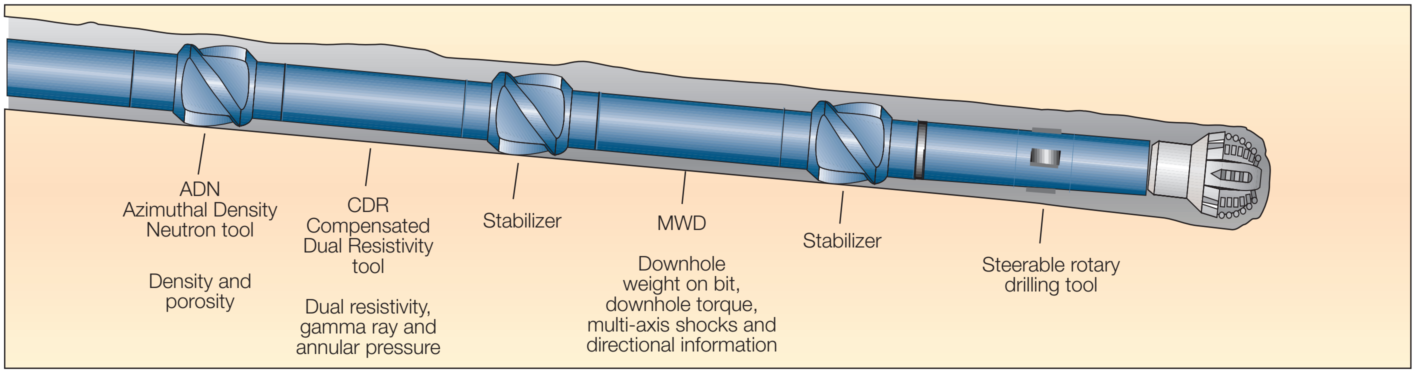
The primary components of the GeoSteering tool are a steerable motor with an instrumented section and a fast wireless telemetry system that passes data to the MWD system higher up in the BHA. The instrumented sub is built into the motor near the bent housing which is typically about 1.5 m [5 ft] above the bit. Packaged in the sub are directional and petrophysical sensors, electronics for control and telemetry and batteries for power. Three inclinometers provide inclination data at the bit in both a survey and continuous mode. Above the GeoSteering tool, a stabilizer with an adjustable gauge allows the directional driller to change the directional characteristics of the BHA in rotary mode.[11] Unfortunately, rotary directional tendencies are not as predictable as those in steering mode. The inclination-at-bit measurement from the GeoSteering tool is critical to judge the cause-effect relationship from gauge changes to well path curve rate. Minor directional changes can be made reliably with rotary drilling, reserving the steering mode for larger or more difficult changes (*previous page*).

The first three extended-reach wells at Wytch Farm, Wells F-18, F-19 and F-20, were designed based on a reservoir characterization developed from the onshore reservoir, 2D seismic surveying and more recent 3D seismic acquisition, outcrop studies and offshore appraisal wells. The basic design in each case was to traverse the reservoir section at a constant angle of 86°. A well encountering a 50-m [160-ft] oil column could then be drilled 20 m [65 ft] above the oil-water contact.[12] These wells were successful and had departures of about 5 km [16,000 ft]. With the additional reservoir information from these wells, subsequent wells were designed with an even larger standoff from the oil-water contact. Wells from the M site accessed poorer-quality sands in the Sherwood reservoir and needed even longer reservoir sections for sufficient well productivity. BP decided to drill the next wells with 7- to 8-km [23,000- to 26,000-ft] ERD stepouts and vertical depth control tolerance of 1 m [3 ft].

At such distances, orienting the pipe in sliding mode would be difficult and time-consuming. Penetration rates would suffer because of the frictional losses reducing the amount of weight reaching the bit. Minimizing the amount of sliding was critical. The nature of the Sherwood reservoir complicated the picture, since it has many distinct zones separated by near-horizontal shales.[13] Previous directional drilling had shown the formation response to be erratic, with rotary mode performance of a BHA varying suddenly and unpredictably from holding angle, to building angle, to dropping angle.

During drilling of the early wells, the MWD survey measure point was typically 20 to 25 m [66 to 82 ft] behind the bit face. The typical BHA consisted of the bit, motor, stabilizer, CDR Compensated Dual Resistivity tool, MWD, and ADN Azimuthal Density Neutron tool (*above*). A simple geometrical calculation showed that if the build rate were to change by 4°/30 m [4°/100 ft], the true vertical depth of the well would be altered by 0.75 m [2.5 ft] before the problem could be detected. With this BHA design, the deviation from plan could be quite large, and only a rapid response with sliding mode drilling would allow the well to stay within the tight tolerances required. Even with

9. Bruce S, Bezant P and Pinnock S: "A Review of Three Years' Work in Europe and Africa with an Instrumented Motor," paper IADC/SPE 35053, presented at the IADC/SPE Drilling Conference, New Orleans, Louisiana, USA, March 12-15, 1996.
   Peach SR and Kloss PJC: "A New Generation of Instrumented Steerable Motors Improves Geosteering in North Sea Horizontal Wells," paper IADC/SPE 27482, presented at the IADC/SPE Drilling Conference, Dallas, Texas, USA, February 15-18, 1994.
   Lesso WG and Kashikar SV: "The Principles and Procedures of Geosteering," paper IADC/SPE 35051, presented at the IADC/SPE Drilling Conference, New Orleans, Louisiana, USA, March 12-15, 1996.
10. Poli S, Donati F, Oppelt J and Ragnitz D: "Advanced Tools for Advanced Wells: Rotary Closed Loop Drilling System—Results of Prototype Field Testing," paper SPE 36884, presented at the SPE European Petroleum Conference, Milan, Italy, October 22-24, 1996.
11. Bonner S, Burgess T, Clark B, Decker D, Orban J, Prevedel B, Lüling M and White J: "Measurements at the Bit: A New Generation of MWD Tools," *Oilfield Review* 5, no. 2 (April/July 1993): 44-54.
12. Harrison PF and Mitchell AW: "Continuous Improvement in Well Design Optimises Development," paper SPE 30536, presented at the SPE Annual Technical Conference and Exhibition, Dallas, Texas, USA, October 22-25, 1995.
13. Cocking DA, Bezant PN and Tooms PJ: "Pushing the ERD Envelope at Wytch Farm," paper SPE/IADC 37618, presented at the SPE/IADC Drilling Conference, Amsterdam, The Netherlands, March 4-7, 1997.



□ ***Steerable rotary assembly. A BHA with a steerable rotary drilling tool was the primary directional system for most of the 12 1/4-in. and 8 1/2-in. sections of Well M-11. The CDR tool was incorporated into the BHA design during the latter part of the 12 1/4-in. section to help identify the top of the reservoir and determine the 9 5/8-in. casing seat.***

sliding, it would be difficult to keep the well within the 1-m vertical tolerance.[14] The solution was to use the GeoSteering tool to provide near-bit inclination data and give immediate warning of any change in BHA response. Gamma ray and resistivity data could also be checked for any unexpected changes in geology. Another drilling equipment change for these long wells was the inclusion of a downhole-adjustable, variable-gauge stabilizer.[15] If the GeoSteering tool identified deviations from the required well path early, then the trajectory could be altered in the rotary mode by adjusting the stabilizer. This BHA design drilled the reservoir sections successfully in Wells M-02, M-03 and M-05.

In Well M-02, with a stepout of 6760 m [22,180 ft] and a reservoir vertical tolerance of 2 m [7 ft], 15% of the reservoir section was drilled in sliding mode, and the stabilizer gauge setting was changed 16 times in drilling 891 m [2923 ft]. The sliding penetration rate was low—only one-third the rate achieved during rotary drilling. BHA performance in Well M-03 was similar, but even better in the M-05 Well. In each case, without the flexibility provided by this set up, considerably more time would have been spent in sliding mode to adjust the well path, with a corresponding decrease in penetration rate.

The highly variable gauge stabilizer has six possible settings between 7¼ in. and 8½ in. The stabilizer blade position is controlled from the surface by applying mud-flow sequences that are interpreted by a microprocessor in the tool. This adjustable stabilizer allowed some degree of build and drop during rotary drilling and worked adequately in previous wells at Wytch Farm, but it did not provide azimuth control.[16]

To drill out 8 km and then on to 10 km, rotary steerable directional systems were tried for even greater control of inclination and azimuth. It was clear that a new type of directional drilling tool would be needed to control direction and azimuth adequately while rotating in the Sherwood at great departures. Several designs were nearing commercialization, each with a different approach to achieving vertical and lateral steering while the drillstring is rotated.

A prototype from Camco Drilling Group Ltd. had been tried on Wells M-08, M-09 and M-10 at Wytch Farm to encourage and accelerate their development and test the feasibility of using these tools to drill the 10-km well.[17] These tools further reduced the amount of time spent on slide drilling. This rotary steerable system synchronously modulates the stabilizer blade extension and contact pressure as a particular blade passes a certain orientation in the wellbore. By applying hydraulic pressure each time a rotating blade passes a specific vertical or lateral orientation, the near-bit stabilizer forces drilling away from that direction. Continuous rotation of the drillstring results in reduced torque and drag and improved hole cleaning.

These improvements led to more efficient weight transfer to the bit and higher penetration rates. Hole direction and dogleg were controlled from the surface during drilling operations by sending information to the downhole tool using a sequence of mud pulses. This coded sequence specified steering commands from the multiple command set preprogrammed into the tool on surface. The BHA at total depth included the bit, steerable rotary system, stabilizer, MWD and LWD (*above*). The steerable rotary drilling system was instrumental in cutting sliding time to less than 5% on the M-11 well and was critical to drilling the well beyond 10 km.

Hydraulics and Hole Cleaning

Selection of a drilling fluid must balance a number of critical factors. The fluid must provide a stable wellbore for drilling long openhole intervals at high angles, maximize lubricity to reduce torque and drag, develop proper rheology for effective cuttings transport, minimize the potential for problems such as differential sticking and lost circulation, minimize formation damage of productive intervals, and limit environmental exposure through a wellsite waste-minimization program.[18] A growing industry trend of designing wells to extend casing seats to longer intervals requires the use of oil-base or synthetic-base mud to provide lubricity to help control torque and drag. This trend means larger hole diameters deeper in the ERD trajectory.

With 8- to 10-km extended-reach sections, the circulation rates necessary to ensure adequate hole cleaning in these larger holes are difficult to attain because of increases in annular pressure losses. These pressure losses increase the equivalent circulating density (ECD) at the end of the well. Higher equivalent circulating densities may cause lost circulation, especially in fractured or depleted upper zones. Higher pump rates ensure a clean hole but may lead to lost circulation from higher ECD.

In Well M-11, annular pressure while drilling was monitored in real time as part of the LWD package. On several occasions, the tool detected increases in ECD and warned the driller before a lost-circulation problem occurred. When the tool detected increases in annular pressure at the BHA, the driller would stop drilling to remove cuttings buildup, thus lowering ECD.

Efficient cuttings transport is one of the primary design considerations for the drilling fluid in an extended-reach well. The factors that affect cuttings transport include drilling-fluid density, low shear-rate rheology, flow rate, cuttings size and concentration in the annulus, drillpipe size, rotary speed and drillstring eccentricity in the wellbore.

Hole cleaning is of critical importance when drilling the high-angle tangent sections of extended-reach wells because of the tendency for cuttings to fall to the low side of the well. To obtain the necessary annular velocities for hole cleaning in high-angle and horizontal sections, high flow rates are needed, resulting in greater demands on the mud pumps. Experience at Wytch Farm has shown that above a tangent angle of 80° in a 12¼-in. hole, flow rates of at least 1100 gal/min [4200 L/min] are necessary to keep the hole clean as it is drilled.

To meet such rates, an existing rig may need to increase the number of mud pumps from two to three, increase the power rating of the pumps from 1600 hp to 2000 hp or more, and increase the pressure rating of the pumps and surface system from 5000 to 7500 psi. A downside to these changes is the increase in capital cost for additional pumps and a doubling of maintenance costs for the higher-pressure equipment.[19] At higher surface pressures, parts replacement will occur more frequently, but having an extra pump results in less disruption to the drilling program during pump repairs.

To maintain sufficient flow rates on the Wytch Farm wells, Deutag's T-47 rig used a 5000-psi surface system and three 1600-hp triplex pumps electronically controlled to increase efficiency. If the three pumps worked independently, there would be potential for synchronization of the cylinders in each pump. In such a case, the pumps could produce pressure surges up to 750 psi, much more than could be handled adequately by the pumps' pulsation dampeners. In effect, this electronic control system worked like a camshaft, keeping the cylinders 40° out of phase with each other. The three pumps worked as one nine-cylinder pump.

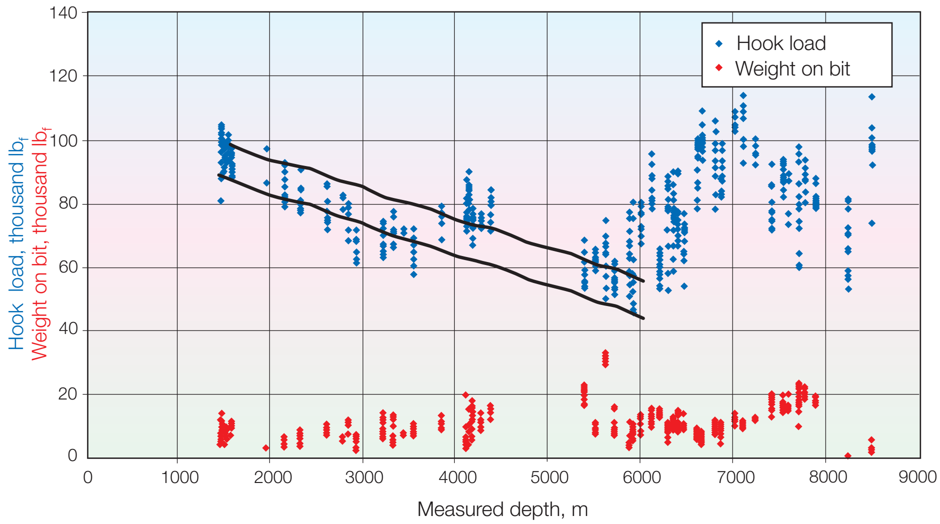
In addition to reducing pressure surges, this system reduced surface vibrations, decreasing the wear and tear on the pumping system, and detected impending pump failure to reduce downtime. A further benefit was an improvement in the quality of the MWD signal. With a smooth, regular pump signal, the MWD pulses were much clearer and easier to read at the surface, improving data quality.

Increasing the pumping capacity of the rig required sufficient capacity in the solids-control equipment, particularly the shale shakers, to handle the increased flow rates. Removing the maximum amount of solids at the shakers reduces the need for further solids-control equipment. The T-47 rig had four state-of-the-art, linear-motion shale shakers. One of these shale shakers was outfitted with larger-mesh screens to salvage and reuse lost-circulation material. Two centrifuges, in line after the shakers, removed fine low-gravity solids.

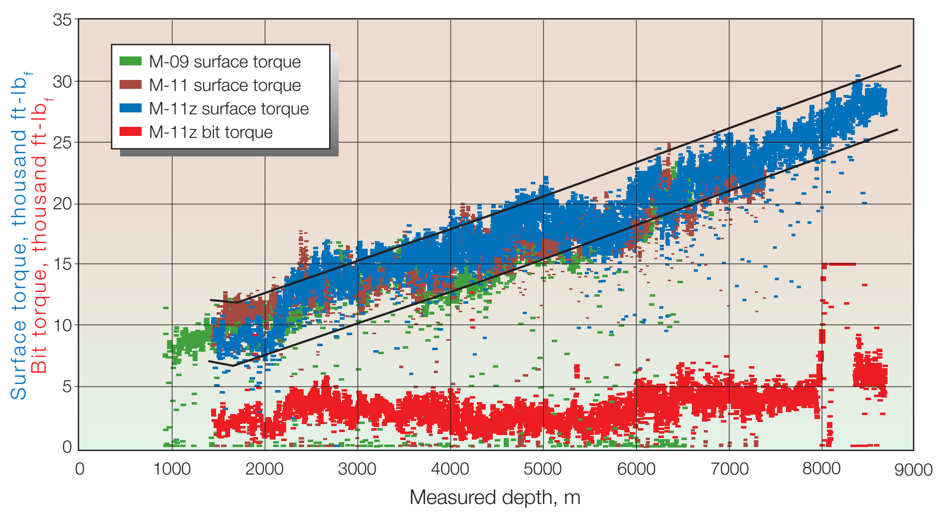
Pipe rotation is another critical factor in hole cleaning. The objective of the hole-cleaning program is to improve drilling performance by avoiding stuck pipe, avoiding tight hole on connections and trips, maximizing the footage drilled between wiper trips, eliminating backreaming trips prior to reaching the casing point and maximizing daily drilling progress.[20] The more an extended-reach well can be drilled in the rotary mode instead of sliding, the better the hole cleaning. Pipe rotation helps prevent cuttings from accumulating around stabilizers, drillpipe protectors and tool joints. Rotating pipe helps disturb any cuttings that may settle to the low side of the wellbore, keeping the cuttings suspended in and transported by the mud. Faster rotational speeds of the pipe improve hole cleaning, but there are some drawbacks to very high rotational speeds. Although good for hole cleaning, excessive rotational speed can increase the severity of downhole vibration and shocks, putting directional drilling and LWD equipment at electronic and mechanical risk. Furthermore, excessive rotary speeds may increase drillpipe and casing wear.

14. Bruce et al, reference 9.
15. Odell AC, Payne ML and Cocking DA: "Application of a Highly Variable Gauge Stabilizer at Wytch Farm to Extend the ERD Envelope," paper SPE 30462, presented at the SPE Annual Technical Conference and Exhibition, Dallas, Texas, USA, October 22-25, 1995.
16. Poli et al, reference 10.
17. Barr JD, Clegg JM and Russell MK: "Steerable Rotary Drilling with an Experimental System," paper SPE/IADC 29382, presented at the SPE/IADC Drilling Conference, Amsterdam, The Netherlands, February 28-March 2, 1995.
18. Payne ML, Wilton BS and Ramos GG: "Recent Advances and Emerging Technologies for Extended Reach Drilling," paper SPE 29920, presented at the International Meeting on Petroleum Engineering, Beijing, China, November 14-17, 1995.
19. Gammage JH, Modi S and Klop GW: "Beyond 8km Departure Wells: The Necessary Rig & Equipment," paper SPE/IADC 37600, presented at the SPE/IADC Drilling Conference, Amsterdam, The Netherlands, March 4-6, 1997.
20. Guild GJ, Wallace IM and Wassenborg MJ: "Hole Cleaning Program for Extended Reach Wells," paper SPE/IADC 29381, presented at the SPE/IADC Drilling Conference, Amsterdam, The Netherlands, February 28-March 2, 1995.

    Lockett TJ, Richardson SM and Worraker WJ: "The Importance of Rotation Effects for Efficient Cuttings Removal During Drilling," paper SPE/IADC 25768, presented at the SPE/IADC Drilling Conference, Amsterdam, The Netherlands, February 23-25, 1993.



Hook load during slide drilling the 12¼-in. section of Well M-11. The hook load during slide drilling followed the expected trend (parallel black lines) down to 6000 m measured depth. After this depth, there was considerable gain in hook load. Beyond 8000 m, applying weight on bit during slide drilling was difficult, if not impossible. Drilling past this measured depth therefore required rotation to overcome friction and allow weight to be transferred to the bit.



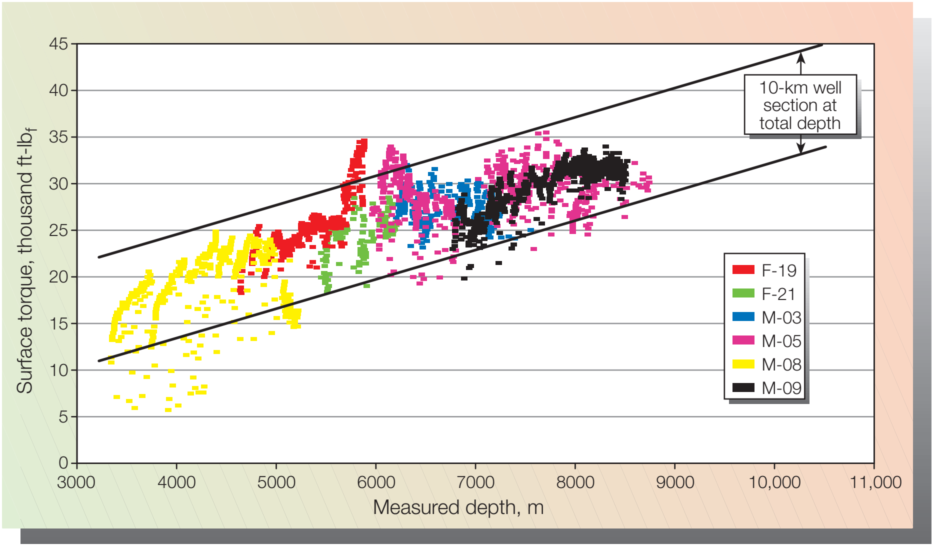
Torque during rotary drilling of the 12¼-in. section of Well M-11. The parallel lines indicate the torque trend predicted for the M-11 12¼-in. section. The recorded surface torque matched the prediction quite accurately.

Torque and Drag

Torque levels have been closely monitored throughout the extended-reach development program. In extended-reach wells, torque levels are generally more dependent on wellbore length than on tangent angle. Higher-angle wells do, however, tend to reduce overall torque levels, as more of the drillstring will be in compression, and consequently, tension and contact forces around the top build section are reduced.

In Wytch Farm extended-reach drilling, three sizes of grade S135 drillpipe were used. In the Well M-11 12¼-in. hole, the drillstring configuration consisted of 8000 m [26,000 ft] of 6⅝-in. drillpipe—a length dictated by the racking capacity within the derrick—on top and 5½-in. pipe below. The larger pipe at the top provided strength to resist torque loads. The main factors in drillstring design in this part of the hole included pump pressure limitations, torque capacity and hole cleaning. In the 8½-in. hole, the drillstring configuration consisted of 4500 m [14,700 ft] of 5-in. S135 drillpipe on bottom and then 5½-in. S135 pipe to surface.

The considerations in drillstring design for the 8½-in. hole included fishing capability, equivalent circulating density and torque capacity. The 5½-in. drillpipe had double-shoulder, high-torque tool joints, and the 5-in. drillpipe joints underwent stress balancing and used high-friction-factor pipe dope to increase the torque capacity to match that of the topdrive. Nonrotating drillpipe protectors were run in trials on earlier wells and helped reduce torque somewhat, but there was a trade-off because they caused an increase in annular pressure drop and therefore in equivalent circulating density. The drillpipe protectors also suppressed drillstring buckling.



Surface torque during reservoir drilling. Modeling the actual surface torque in the 8½-in. sections of offset wells produced reasonable estimates of the expected torque at 10-km. The predicted torque range at 10 km reaches the upper limit of the top-drive capacity.

In drilling extended-reach wells, drillpipe is rotated not by the rotary table but instead by the topdrive, which travels the length of the derrick and permits drilling with an entire stand of pipe. The topdrive also provides backreaming capacity and the capability to push casing down the well when high drag is encountered. Maximum output from the top-drive system is closely related to the maximum torque capacity of the drillpipe used. The Deutag T-47 rig has a continuous top-drive output of 45,000 ft-lb_f and a maximum intermittent rating of 51,000 ft-lb_f. Inevitably there will be some torsional variation, so the top-drive torque rating needs to be sufficiently high to accommodate these peak values.

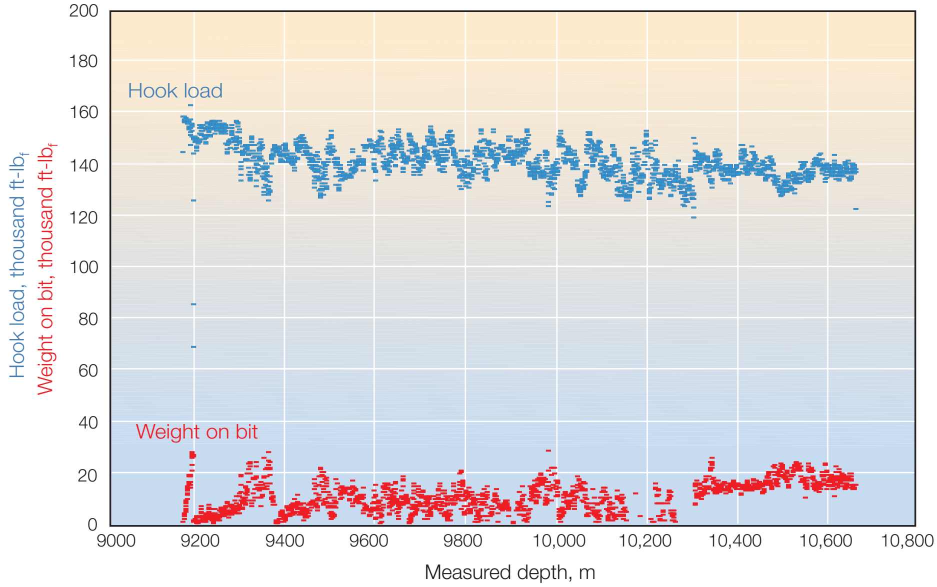
The use of MWD tools that measure downhole torque, rotational speed and downhole weight on bit in real time helps identify conditions that lead to stick-slip, which can produce detrimental torque variations in the drillstring. During stick-slip, the bit will alternately stop rotating (stick) and then accelerate (slip) while the drillstring rotates at a constant speed. The long drillstring can wind and unwind when this occurs, leading to excessive torque on connections, drillstring failures, premature bit wear, BHA failures and inefficient drilling. Fluctuations in drillpipe torque from downhole stick-slip can be minimized by adjusting drilling parameters—weight on bit, pump rate or rotational speed—provided fluctuations in downhole torque are detected early.

Changing design parameters to control surface torque is not necessarily beneficial in minimizing drag. Overcoming axial drag in these high-angle wells is a significant challenge (*previous page, top*). The critical operations, in particular, are running the 9⅝-in. casing inside the 12¼-in. hole and drilling the 8½-in. hole in an oriented mode. Experience to date has shown that running the liner and completion tubing is less difficult yet still requires close monitoring of drag.

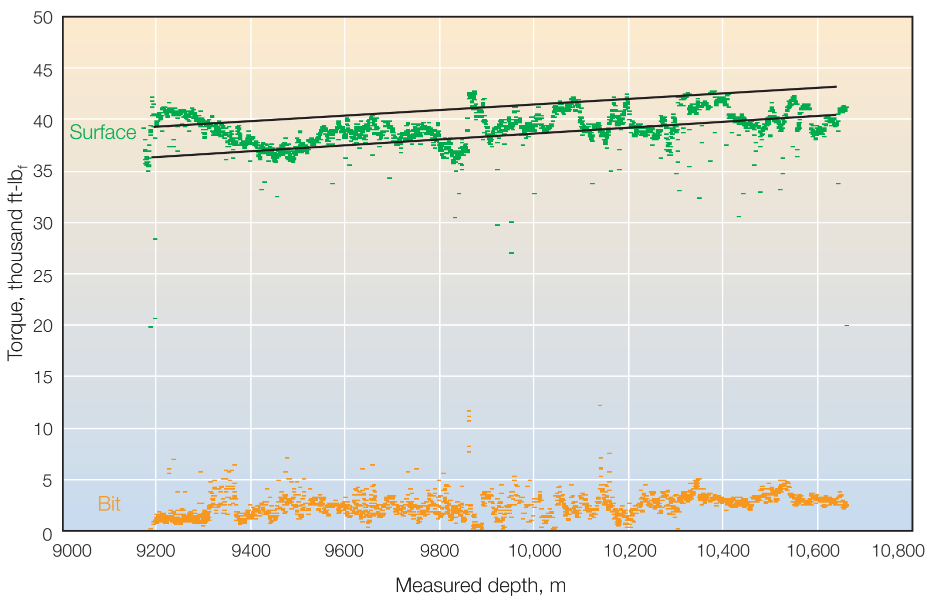
Extensive reviews of previous wells helped predict surface torque for the 12¼-in. section of Well M-11. Two independent methods were used to analyze these data. The first method, composite forecasting, is a plot of surface torque from all previous Wytch Farm extended-reach wells with upper and lower trend lines used to predict torque ranges for the section. The second technique uses a drillstring simulator program to examine torque values from the most recent wells and calculate upper and lower bounds for the section. This determination of friction factor has proven remarkably consistent for the 12¼-in. section (*previous page, bottom*). These analyses uncovered a strong correlation between wellbore length and torque in the 12¼-in. hole.

Similar analyses were performed on the 8½-in. hole to predict likely torque values. Composite plots from previous wells showed a trend of increasing torque with measured depth (*above left*). Close assessment of each well generated some unexpected results: torque levels tended to flatten after a certain length of openhole section was drilled, resulting in low openhole friction factors.

These low-friction factors reflect good hole-cleaning practices and controlled addition of fibrous lost-circulation material. Crushed almond hulls helped control fluid loss in the reservoir section, and this lost-circulation material had a beneficial side effect in that it reduced drillstring torque in openhole sections during rotary drilling. These materials apparently form a low-friction layer between the drillstring and formation. Once this relationship was discovered, a recovery system was added to the rig shale shakers to collect and reuse the lost circulation material continuously as part of the torque-reduction program. The effect of hole cleaning on torque is significant in the 8½-in.



□ ***Hook load and weight on bit in the 8½-in. section of Well M-11. During rotary drilling the 8½-in. section, the hook load decreased slightly while still maintaining effective weight on bit. Rotating the pipe lowered friction factors and helped keep the hole clean to allow successful drilling past 10 km.***



□ ***Torque in the 8½-in. section of Well M-11. Bit torque remained relatively stable throughout the 8½-in. reservoir section. The surface torque showed some fluctuation but remained within the range predicted (parallel black lines) by torque and drag simulators.***

hole. Low-torque troughs form after periods circulating the well clean following a BHA change or after a wiper trip. Higher torque levels occur after slide drilling or rotary drilling a long section (*left, top and bottom*).

Casing Flotation

One of the major hurdles to overcome in drilling and completing a 10-km well was running 9⅝-in. casing to a departure beyond 8000 m. Experience on other Wytch Farm wells showed that running the 9⅝-in. casing became increasingly difficult with greater departures. Casing design analyses using friction factors from offset wells indicated that drag would be too high to run the planned 8800 m of casing conventionally in Well M-11, even with full weight from the travelling block.

Various options, such as a tapered casing string, altered fluid properties and casing flotation, were tried on intermediate-length wells to identify the best approach for Well M-11. Of the options tried, casing flotation proved to be the only method with sufficient potential to get the casing to total depth. In principle, casing flotation is a simple technique. Essentially, casing is not filled as each joint is run into the wellbore, as is done in typical casing operations. The goal is to have the casing close to neutrally buoyant, so it becomes virtually weightless in the mud, and drag is minimal.

On Well M-03, the entire 9⅝-in. casing string was floated into the well to observe the actual running weight compared to predictions. This exercise was important because it indicated that the mud weight as measured at the surface needed to be slightly lower than calculated to reduce positive buoyancy and allow the casing to sink. The mud rheology had to be reduced as much as possible prior to running the casing because of the high surge pressure caused as the casing was pushed into the well.[21]

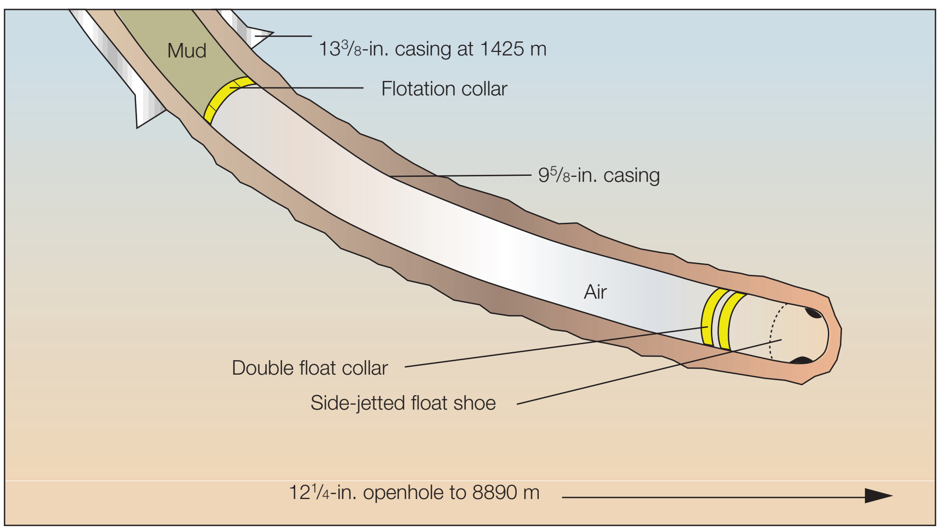
21. Cocking et al, reference 13.

In a long extended-reach section, an entire air-filled casing string can become positively buoyant and resist being pushed farther into the well. In such cases, the technique is altered by partial casing flotation, during which the casing string is divided into two sections with the lower portion filled with air and the upper section filled with mud. The section filled with mud is in the near-vertical section of the well and provides weight to help push the lower, buoyant casing into the well. A shear-out plug separates the air-filled and mud-filled sections of casing. The plug holds the mud in the upper section but can be opened with applied pump pressure to circulate fluid through the entire casing string.

In a further prelude to Well M-11, the 9⅝-in. casing was partially floated on Well M-08. The mud weight and rheology were decreased prior to running the casing. The first 2000 m [6600 ft] of casing were run with air. A shear-out plug was run in the casing at that point, and the remaining 1500 m [4900 ft] to surface was run and filled conventionally. In addition to flotation, the casing was also rotated at various times during the operation. Rotating the casing on Well M-08 was merely a test of the procedures before they had to be used on Well M-11. Once the casing begins to float in the well, the actual torque required for rotation is small. In fact, the actual running weight and torque closely matched predicted values, proving that these techniques could be used effectively on the extreme-departure well.

This flotation method was used again on Well M-09 to run 9⅝-in. casing to 6580 m [21,589 ft]. This flotation method was eventually deployed on Well M-11 to run 9⅝-in. casing to 8890 m [29,162 ft] measured depth (*below*). The casing was floated to 7080 m [23,228 ft] prior to installation of the flotation collar. The casing was run into the openhole for another 20 stands prior to filling the upper section of casing to achieve the additional running weight.

To handle positive casing buoyancy safely, a push-tool was installed below the topdrive on the rig. This tool engaged over the box connection of the casing and allowed the full weight of the topdrive and blocks to be applied to the string. A set of bidirectional, hydraulic, flush-mounted slips held the buoyed casing in the hole. The slips were anchored to the rotary table and provided the necessary hold-down force on the casing.



Partially floated 9⅝-in. casing. Casing flotation experiments on Wells M-03, M-08 and M-09 proved the concept for the extreme test in Well M-11. The bottom section of casing, containing air, remained neutrally buoyant to allow the casing to slide more easily along the well path. The mud-filled upper section provided the weight necessary to push the entire string to bottom. Once the casing was landed, pump pressure was applied to shear the plugs in the flotation collars and allow circulation.

A Look at the Future

Well M-11 was completed with an electrical submersible pump and brought into production on January 12, 1998, at a rate of 20,000 BOPD [3200 m^3/d]. Wytch Farm production currently averages more than 100,000 BOPD [16,000m^3/d], 80% of which comes from extended-reach wells.

The design of Well M-11 took more than a year, and its completion provided an excellent test of the industry's capabilities. The success of this well has opened up even more targets and the potential to access reserves that would have remained out of reach or required huge capital outlays just a few years ago. The current focus at Wytch Farm is to drill 5-km stepout infill wells faster and cheaper than previous wells. Another extreme well, with a stepout of some 11 km [36,000 ft], is in the initial planning stages. Also under consideration are several 6- to 8-km multilateral wells.

All aspects of extended-reach technology have to move forward. The next step will be in completions and interventions, where wellbore workovers and maintenance will be critical.

The future for GeoSteering technology and rotary steerable tools is bright. Currently, these steerable systems are used primarily on relatively expensive extended-reach wells where they can provide a technical capability beyond the limit of standard motor-driven systems. Here, these systems can be run economically even if their cost is high. Further work will focus on increasing the reliability, upward telemetry systems and operating time of these tools while cutting costs.

—KR