

Using Casing to Drill Directional Wells

Drilling with large-diameter tubulars eliminates the need to run conventional drillpipe, which then must be pulled to install permanent casing. It can mitigate lost circulation, enhance well control and reduce nonproductive rig time, and also decrease the risk of unintentional sidetracks or stuck pipe. Fewer trips into and out of a well, improved wellsite safety, increased efficiency and lower cost have led to an expanding range of applications that now includes casing directional drilling.

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The use of casing for drilling is an emerging technology that can reduce well-construction costs, improve operational efficiency and safety, and minimize environmental impact. Fundamentally simple in principle, this drilling technique uses the large-diameter tubulars that will be permanently installed in a wellbore in place of conventional drillpipe. The economic demands of complex geologic settings, smaller reservoirs with limited recoverable reserves, and the need to optimize development and exploitation of mature fields make drilling operations with casing increasingly attractive to operating companies.

A conventional rotary drill bit or a special drilling shoe can be attached to the end of a casing string to drill vertical wells. For additional flexibility and for those applications that require directional control, a retrievable bottomhole assembly (BHA) for drilling can be deployed, locked in place and then retrieved by wireline cable. Running and retrieving this BHA through casing eliminate tripping of drillpipe into and out of a wellbore and provide added protection for the advanced systems used in downhole measurements and directional-drilling applications.

Minimizing the number of pipe trips during drilling operations reduces incidents of hole collapse from swabbing and surging, decreases the chance of an unintentional sidetrack and minimizes wear inside previously installed surface or intermediate casing strings. After reaching total depth (TD), the casing is already in place, eliminating the need to pull drillpipe and then run permanent casing.

This reduction in pipe handling improves wellsite safety and allows drillers to use standard-size rigs or smaller rigs built specifically to drill with casing. New compact rigs for drilling operations with casing require lower horsepower, use less fuel, produce fewer emissions, operate from smaller surface locations, and can be moved more quickly and easily than larger conventional rigs ([next page](#)).

Compared with traditional drilling operations, casing while drilling minimizes rig downtime resulting from unexpected occurrences, such as stuck pipe or loss of well control from an influx, or kick, of formation fluid. Anecdotal evidence indicates that drilling with larger diameter tubular connections reduces lost circulation by mechanically plastering cuttings and drilled solids into the borehole wall.

It is possible that this “smearing” effect builds an impermeable filtercake or creates a solid surface finish that may allow weak, low-pressure and depleted intervals to be drilled without significant loss of drilling fluid.

Casing strings have longer joints than standard drillpipe, which means that drillers make about 25% fewer connections. Another benefit is less time spent circulating fluid or backreaming to maintain hole stability while making pipe connections. In addition to improving drilling efficiency, both of these advantages further reduce overall cost and environmental impact.

Drilling operations with casing eliminate several steps in the conventional well-construction process and provide other critical advantages, including better fluid circulation and removal of formation cuttings for more effective hole cleaning. As operators gain experience in an area, drilling penetration rates with casing usually improve, ultimately matching or surpassing penetration rates previously achieved with drillpipe when comparing days per 1,000 ft [305 m] or feet per day.

Analysis of wells drilled to date with casing indicates that this technique can reduce nonproductive rig time by as much as 50% and cut drilling time by a nominal 10 to 35% per well in some applications. About one-third of this reduction results from decreased tripping of pipe; the remainder comes from avoiding unexpected drilling problems and from eliminating the time required to install casing in a separate operation.

This faster, simpler and more efficient process translates into fewer drilling surprises and lower costs. Advances in tools, equipment and procedures are expanding the use of this technology for drilling soft and hard formations both onshore and offshore, and most recently for casing directional drilling.

We first review the use of casing for drilling, including ongoing infill development activity in south Texas, and then discuss how simultaneously drilling and casing a well helps reduce borehole problems. The results from recent testing of directional operations with casing demonstrate how rotary steerable system (RSS) technology improves drilling efficiency compared with steerable downhole motors, especially for smaller borehole sizes.



^ Casing while drilling and casing directional drilling. During the past five years, ConocoPhillips and Tesco Corporation drilled extensively with casing—more than 1,050,000 ft [320,040 m]—in south Texas, recently expanding applications to include directional operations and compact purpose-built rigs, such as the one shown here. This technique improved drilling efficiency and effectively eliminated lost circulation in about 110 wells. These results and similar experience in other areas indicate that casing can be used to avoid lost circulation and drill through pressure-depleted zones in mature fields that are difficult to drill using conventional drillpipe, onshore and offshore.

A Fundamental Change in Well Construction

Both positive-displacement motor (PDM) and RSS technologies utilize drillpipe. This specially designed, thick-wall pipe is run to the bottom of a borehole and pulled back out, perhaps several times while drilling a well, and again to install and cement a permanent string of casing during a separate operation distinct from the rest of the drilling process.

Introduction of the downhole PDM in the 1960s facilitated drilling without full-string pipe rotation. These systems use mud flowing through a turbine or a rotor-stator power section to generate torque downhole. Steerable motors with a fixed bend angle, or bent housing, allow simultaneous control of borehole azimuth and inclination angle, which subsequently resulted in better directional control and routine construction of high-angle wellbores, horizontal borehole sections in the 1980s and, eventually, extended-reach wells in the 1990s.

In the late 1990s, rotary steerable systems helped operators set new records in extended-reach drilling (ERD). This technology, including the Schlumberger PowerDrive and PowerDrive Xtra rotary steerable systems, and the PowerDrive Xceed rotary steerable system for harsh, rugged environments, facilitates directional control and steering of the bit while continuously rotating the entire drillstring.

Roller-cone or fixed-cutter bits on the end of rotating drillpipe have monopolized the drilling of oil and gas wells for a century. However, new concepts and design improvements in rotary rigs and drill bits have been the norm since these tools were introduced in the early 1900s. As a result, penetration rates and bit life have improved dramatically during this period.¹

Using casing to drill oil and gas wells represents a fundamental change in the process of constructing a wellbore. Casing while drilling provides the same hole-making capability as drillpipe operations, with better removal of drilled cuttings and improved hole-cleaning performance. The casing used for drilling can be a partial liner or a full string (right). From its earliest applications until the recent surge in activity, using casing for drilling has shown significant potential compared with conventional drilling.

In the 1920s, the Russian oil industry reported the development of retractable bits for use in drilling operations with casing. In the 1930s, operators in the continental USA used production tubing to drill openhole, or barefoot, completions. The tubing string and the flat-blade, or fishtail, bit used for drilling remained in the well after production flow began. Permanent

wellbore tubulars also have been used for slimhole drilling at various times since the 1950s.

In the 1960s, Brown Oil Tools, now Baker Oil Tools, patented a relatively advanced system for drilling with casing that included retrievable pilot bits, underreamers to enlarge hole size, and downhole motors. However, low penetration rates compared with conventional rotary drilling restricted the commercial application of this system.²

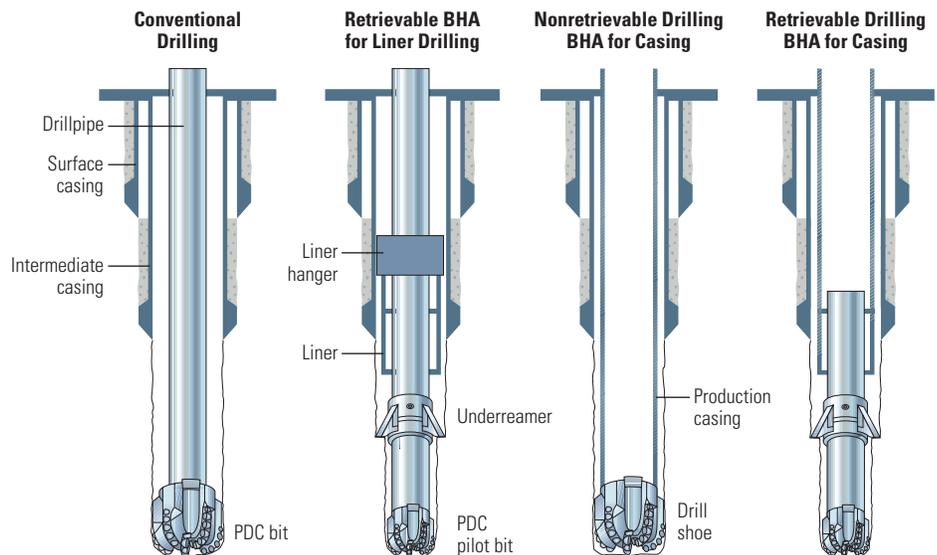
Research and development continued at a slow pace until the late 1980s, when economic and market conditions stimulated renewed interest in drilling with conventional tubing, coiled tubing and other slimhole techniques. At about the same time, Amoco, now BP, documented success drilling and coring with mining equipment and tubulars. In the 1990s, operators began using liners to drill from normally pressured formations into pressure-depleted intervals.

This approach avoided problems, such as hole instability and enlargement, lost circulation and well control, which plagued conventional drilling operations. Mobil, now ExxonMobil, used partial liners to drill from higher pressure transition zones into the extremely depleted limestone reservoirs of

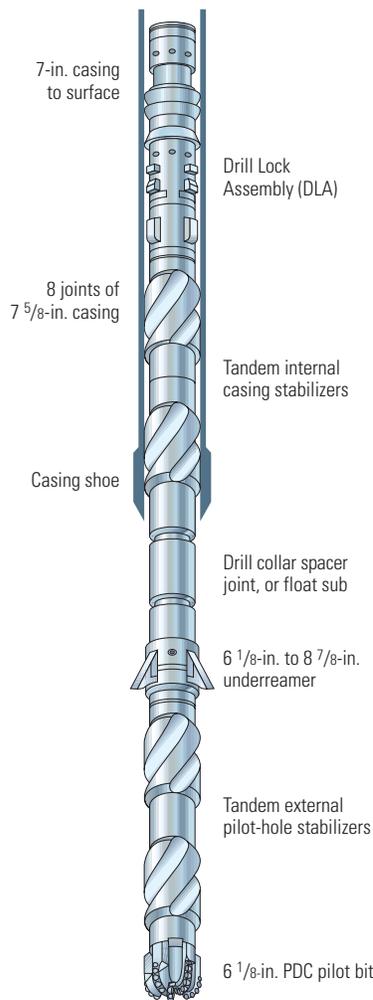
the Arun gas field in North Sumatra, Indonesia.³ Amoco also employed this technique to drill wells in the Norwegian North Sea Valhall field.⁴

In 2001, BP and Tesco reported success using casing to drill surface and production casing intervals for 15 gas wells in the Wamsutter area of Wyoming, USA. These wells ranged in depth from 8,200 to 9,500 ft [2,499 to 2,896 m].⁵ At about the same time, Shell Exploration and Production Company dramatically improved drilling performance in south Texas by drilling underbalanced with casing, realizing a cost reduction of about 30%.⁶

To date, operators have drilled more than 2,000 wellbore sections using casing. More than 1,020 of these intervals have involved vertical drilling with casing and nonretrievable bits, about 620 were drilled using partial liners, more than 400 used a retrievable BHA for vertical drilling, and about 12 used a retrievable BHA for directional drilling. All of these early applications helped casing while drilling evolve from a new technology with unproven reliability to a practical solution that can reduce costs, increase drilling efficiency and minimize nonproductive rig time.



^ Simultaneous drilling and casing with partial liners or full casing strings. Drilling operations traditionally involved roller-cone or fixed-cutter bits on the end of rotating drillpipe (left). As alternatives to this standard approach, operators and service companies developed and tested various systems for drilling with liners and casing. Drilling with a partial liner uses enough pipe to case the open hole and omits the upper part of the casing string (middle left). Conventional drillpipe conveys the bottomhole assembly (BHA) to target depth and carries the main drilling loads. A liner hanger or packer connects the drillstring with the liner. The BHA can be retrieved only when the hole is finished. If a BHA failure occurs, the entire drillstring and liner must be pulled. Liner hanger position within the previous casing string limits the maximum drilling depth. A full string of casing with a nonretrievable drillable bit (middle right) or a retrievable drilling BHA (right) provides additional functionality and flexibility. The retrievable BHA can be deployed and retrieved with smaller jointed pipe, coiled tubing or wireline cable without tripping casing into and out of a well.



^ Casing vertical drilling. The retrievable bottomhole assembly (BHA) for vertical drilling includes a small bit that drills a guide, or pilot, hole (*left*). An underreamer with expandable and retractable cutter pads expands this initial borehole to accept the full diameter of the casing being used. Stabilizers between the pilot bit and the underreamer maintain borehole inclination. Upper stabilizers located inside the casing reduce BHA vibrations and protect the Drill Lock Assembly (DLA), which provides an axial and torsional connection to the casing (*right*). The Tesco DLA seals against the casing to direct drilling fluid through the bit. It also allows fluid to bypass the BHA during wireline deployment and retrieval. A positive-displacement motor (PDM) or a rotary steerable system (RSS), heavyweight drill collars, measurements-while-drilling (MWD) systems or logging-while-drilling (LWD) tools, not shown here, can be included. The DLA is run on wireline and landed in a profile nipple near the bottom of the casing. The BHA is positioned in the last casing joint so that all components below the tandem stabilizer extend into the open hole below casing.

A New Approach

Some operators now view this technology as a potential solution in a variety of commercial applications, ranging from drilling entire onshore wells to drilling just one or two hole sections in offshore wells that require multiple casing strings.⁷ Drillers categorize the downhole systems that are used to drill with casing as nonretrievable or retrievable. A nonretrievable, or fixed, assembly can be used to drill with short liners or full casing strings.

Conventional rotary bits that remain in the wellbore after reaching TD have been used in some applications. The bit can remain on the casing and be cemented in place, or it can be released and dropped into the bottom of the hole to allow logging. Drillable drill bits, such as the Weatherford Type II or Type III DrillShoe or the Baker Hughes EZ Case, have external cutting structures for drilling, but can be removed by milling. These specially designed casing shoes allow drilling and completion of subsequent borehole sections.

A retrievable system allows the bit and BHA to be deployed initially and replaced without tripping casing into and out of the hole.⁸ This option is the only practical choice for directional wells because of the need to recover expensive BHA components, such as downhole motors, rotary steerable systems or measurements-while-drilling (MWD) and logging-while-drilling (LWD) tools. A wireline-retrievable system facilitates replacement of equipment that fails before reaching TD, and allows quick, cost-effective access to log, evaluate and test formations.

Several service providers are committed to developing tools, techniques and equipment for drilling with casing. Tesco, for example, offers Casing Drilling services, comprising purpose-built rigs, surface equipment and downhole tools for onshore applications.

To facilitate the use of casing for drilling, Tesco designed robust, reliable surface equipment and downhole systems that efficiently and effectively attach to and release from casing. A wireline-conveyed drilling assembly is typically suspended in a profile nipple near the bottom of a casing string. The Tesco Casing Drilling system uses a Drill Lock Assembly (DLA) to anchor and seal the BHA inside casing (*left*).⁹

1. Besson A, Burr B, Dillard S, Drake E, Ivie B, Ivie C, Smith R and Watson G: "On the Cutting Edge," *Oilfield Review* 12, no. 3 (Autumn 2000): 36–57.
2. Hahn D, Van Gestel W, Fröhlich N and Stewart G: "Simultaneous Drill and Case Technology—Case Histories, Status and Options for Further Development," paper IADC/SPE 59126, presented at the IADC/SPE Drilling Conference, New Orleans, February 23–25, 2000.
3. Sinor LA, Tybero P, Eide O and Wenande BC: "Rotary Liner Drilling for Depleted Reservoirs," paper IADC/SPE 39399, presented at the IADC/SPE Drilling Conference, Dallas, March 3–6, 1998.
4. Tessari RM and Madell G: "Casing Drilling—A Revolutionary Approach to Reducing Well Costs," paper SPE/IADC 52789, presented at the SPE/IADC Drilling Conference, Amsterdam, March 9–11, 1999.
5. Shepard SF, Reiley RH and Warren TM: "Casing Drilling: An Emerging Technology," paper IADC/SPE 67731, presented at the SPE/IADC Drilling Conference, Amsterdam, February 27–March 1, 2001.
6. Gordon D, Billa R, Weissman M and Hou F: "Underbalanced Drilling with Casing Evolution in the South Texas Vicksburg," paper SPE 84173, presented at the SPE Annual Technical Conference and Exhibition, Denver, October 5–8, 2003.
7. Hossain MM and Amro MM: "Prospects of Casing While Drilling and the Factors to Be Considered During Drilling Operations in Arabian Region," paper IADC/SPE 87987, presented at the IADC/SPE Asia Pacific Drilling Technology Conference and Exhibition, Kuala Lumpur, September 13–15, 2004.
8. Warren T, Tessari R and Houtchens B: "Casing Drilling with Retrievable Drilling Assemblies," paper OTC 16564, presented at the Offshore Technology Conference, Houston, May 3–6, 2004.
9. Warren TM, Angman P and Houtchens B: "Casing Drilling Application Design Considerations," paper IADC/SPE 59179, presented at the IADC/SPE Drilling Conference, New Orleans, February 23–25, 2000. Shepard et al, reference 5. Warren T, Houtchens B and Madell G: "Directional Drilling with Casing," paper SPE/IADC 79914, presented at the SPE/IADC Drilling Conference, Amsterdam, February 19–21, 2003.

Each BHA component must pass through the casing string that is used for drilling, including an underreamer, or hole enlarger, with retractable pads. A pilot bit initiates a small hole, which then is enlarged by cutters on the expanded underreamer pads. Drillers commonly use a 6 1/8-in. or a 6 1/4-in. pilot bit and an underreamer that expands to 8 1/2 in. when drilling with 7-in. casing. The underreamer can be located immediately above the bit outside the casing or above other BHA components in the

pilot hole. A topdrive unit rotates the casing and applies torque to make tubular connections.

The Tesco quick-connect Casing Drive System, which is operated by the topdrive hydraulic control system, speeds up pipe handling and prevents damage to casing threads by eliminating one cycle of making and breaking connections at tubular joints (below).¹⁰ A slip assembly grips either the exterior or interior of the casing, depending on pipe size, and attaches the casing to the topdrive without threaded

connections. An internal spear assembly provides a fluid seal inside the pipe.

Initially, drilling operations with casing were performed onshore in vertical wells to avoid the additional complexity of offshore operations. As a result, casing vertical drilling advanced to a point where it routinely rivaled the efficiency of operations with conventional drillpipe. Tesco Corporation and ConocoPhillips have drilled more than 100 of these vertical wells in south Texas.

A Proving Ground in South Texas

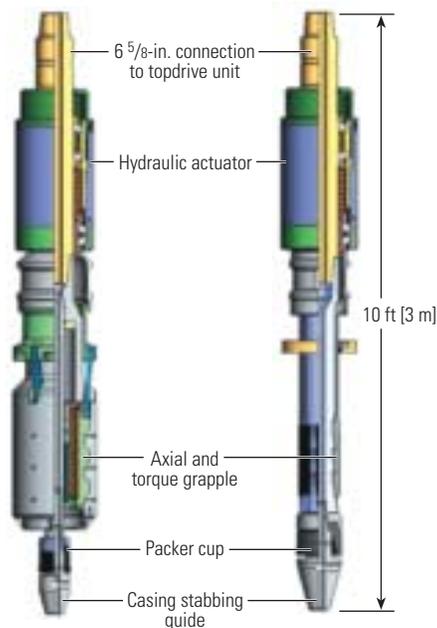
ConocoPhillips initiated an infill-drilling program in 1997 to increase production and recovery from geopressured Wilcox sands in the south Texas Lobo geologic trend. Operators discovered natural gas in these low-permeability, or tight, sands near the USA and Mexico border in the 1960s, but limited well productivity, low gas prices and inadequate pipeline capacity made commercial development uneconomic.

From 1979 to the mid-1990s, US tax incentives for tight-gas development, advances in hydraulic fracture stimulation, new pipeline construction and higher gas prices resulted in the drilling of more than 1,000 wells. Since 1997, ConocoPhillips has drilled another 900 wells, ranging in depth from 7,500 to 13,000 ft [2,286 to 3,962 m], to recover additional gas reserves in this area.

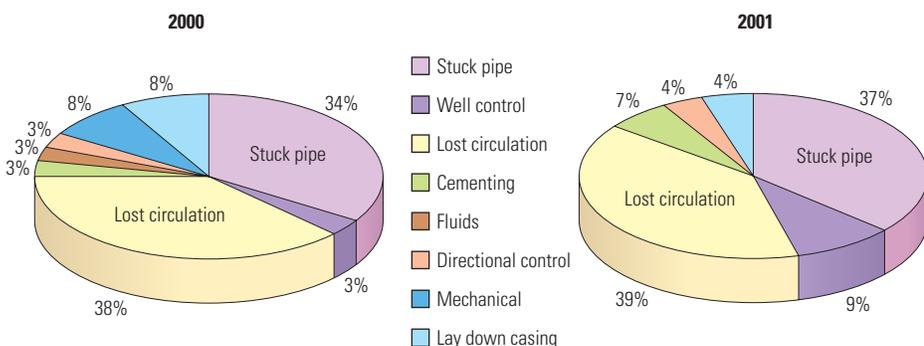
Most of these wells were drilled in a single run with conventional drillpipe and polycrystalline diamond compact (PDC) fixed-cutter bits. Despite extensive experience in this mature area, drilling efficiency peaked in 2001 after about 600 wells. Rig downtime represented less than 10% of the total time to drill a Lobo well, so a new approach was required to reduce well-construction costs further.

In 2001, ConocoPhillips began reevaluating well-construction practices to increase drilling efficiency enough to make exploitation of smaller Lobo reservoirs with less than 1,000 million ft³ [28.3 million m³] of recoverable gas economical. This would allow development activity to continue for several years in this highly faulted and compartmentalized geologic trend.

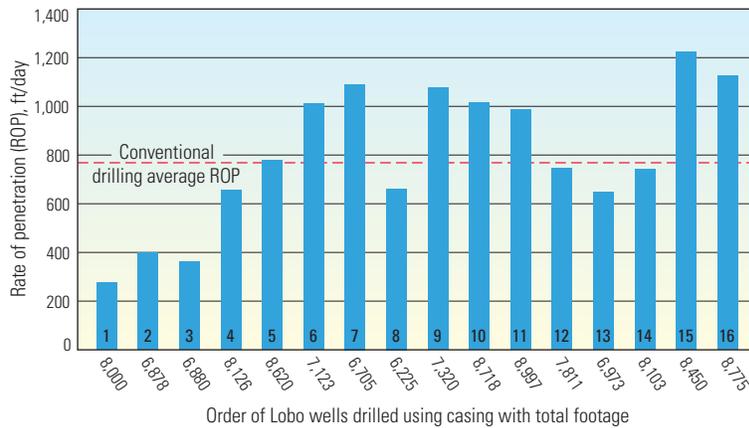
Even though surface, intermediate and production intervals could be drilled conventionally, downhole drilling problems and rig downtime near the TD of each casing section continued to impede performance. Lost circulation, stuck drillpipe and inability to run casing to TD were common in Lobo trend wells, accounting for about 75% of trouble time in 2000 and 2001 (left).



▲ Surface equipment for casing while drilling. The Tesco Casing Drive System comprises a quick-connect slip assembly that grips either the exterior (*left*) or interior (*middle*) of the casing, depending on pipe size, and attaches the casing to the topdrive without threaded connections to prevent thread damage. An internal spear assembly provides a fluid seal inside the pipe. The Casing Drive System is operated by a topdrive system that is suspended from the derrick block, so the entire topdrive rotary mechanism is free to travel up and down (*right*). A topdrive differs radically from the more conventional rig-floor rotary table and Kelly method of turning the drillstring because it allows drilling to be performed with three joints at a time instead of single joints of pipe. It also allows drillers to quickly engage the rig pumps or the rotary drive while tripping pipe, which minimizes both the frequency of stuck pipe and the cost per incident.



▲ Nonproductive, trouble time for conventionally drilled wells in the south Texas Lobo trend. Lost circulation and stuck pipe were found to be the major causes of trouble encountered while drilling Lobo field wells with conventional drillpipe. In 2000 and 2001, these two problems accounted for 72% and 76%, respectively, of the trouble time. Well control and inability to successfully run casing to TD also were significant in these and other years.



▲ Improvements in the efficiency of casing while drilling. Rate of penetration improved dramatically during the course of initial vertical drilling operations with casing in the south Texas Lobo trend. By the end of Phase 1, a five-well pilot program, the performance of casing while drilling matched that of conventional operations with drillpipe. Well 7 included 705 ft [215 m] of hole drilled directionally with casing and a downhole motor. Well 8 included a 902-ft [275-m] section drilled directionally with drillpipe and heavyweight drilling collars.

During conventional drilling operations, additional fluid, or mud, often had to be circulated to recondition the borehole and address problems such as lost circulation, sloughing formations and hole collapse in pressure-depleted intervals. Gas influx at intermediate casing points or across productive zones, and stuck-pipe conditions while drilling or running casing also were problems. As a result, well-control incidents were a major concern. ConocoPhillips identified casing while drilling as a technology that might solve these problems and improve drilling efficiency.¹¹

Many well-control incidents and blowouts occur while tripping pipe. Using casing to drill helps avoid these unexpected, dangerous and potentially costly events. Drilling operations with casing minimize or eliminate pipe trips and leave casing at the bottom of a borehole, the best position to circulate out an influx. This is an important advantage, especially as this technique is applied in more applications under increasingly complex subsurface conditions.

The first phase of evaluating drilling operations with casing involved a five-well pilot program. Beginning in late 2001 and continuing into 2002, ConocoPhillips extended this program to determine whether casing while drilling could

compete with conventional drilling across the entire Lobo trend. This second phase proved that drilling with casing mitigates formation-related rig downtime associated with conventional operations.

Downtime on the next 11 wells drilled with casing consisted primarily of rig mechanical and operational-related problems; there were virtually no incidents of stuck pipe or lost circulation. In addition, many of the mechanical and operational problems were reduced or eliminated. During the first two phases of this program, the performance of Tesco Casing Drilling systems steadily improved, matching the average daily penetration rate of conventional operations by the fifth well and eventually exceeding it (left).

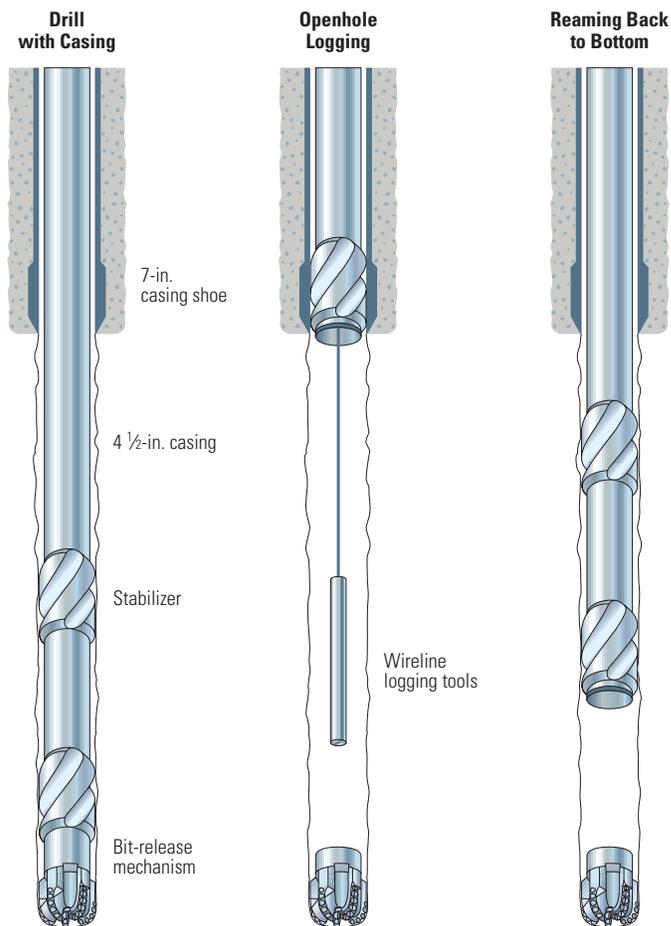
The surface-casing sections of wells in the Lobo program were drilled with 9½-in. casing using an 8½-in. PDC pilot bit and a 12¼-in. underreamer in a retrievable BHA. ConocoPhillips drilled this interval in one run for all of the wells and encountered few problems retrieving the BHA with wireline. Actual drilling, or rotating, times with casing were slightly higher than conventional operations using drillpipe and a 12¼-in. rotary drill bit.

These 500-ft [152-m] sections were completed—drilled, cased and cemented—in about the same time as conventionally drilled surface holes. Cement inside the 9½-in. casing was drilled out with 7-in. casing using a 6½-in. PDC bit and 8½-in. underreamer configured to mill and clean out inside casing. After drilling through cement inside the casing and then into a few feet of formation below the casing set point, or shoe, this BHA was retrieved and replaced with another for drilling 8½-in. open hole.

In early wells, this second BHA drilled to a depth where formations become harder, typically about 6,500 ft [1,981 m]. A third BHA drilled to the 7-in. casing point. In most cases, the bit and underreamer had little wear at either point. After gaining more experience, ConocoPhillips began drilling this entire intermediate casing section in a single run.

10. Warren T, Johns R and Zipse D: "Improved Casing Running Process," paper SPE/IADC 92579, presented at the SPE/IADC Drilling Conference and Exhibition, Amsterdam, February 23–25, 2005.

11. Fontenot K, Highnote J, Warren T and Houtchens B: "Casing Drilling Activity Expands in South Texas," paper SPE/IADC 79862, presented at the SPE/IADC Drilling Conference, Amsterdam, February 19–21, 2003.



▲ Procedure for logging after drilling with casing. A technique for running openhole wireline logs for formation evaluation that proved effective in the Lobo development program was to drill to TD with 4½-in. casing and release the bit (*left*). The next step was to ream back to the 7-in. casing shoe, so openhole logs could be run through the 4½-in. casing just as they would if the well were drilled conventionally (*middle*). The 4½-in. casing was then reamed back to TD (*right*).

Borehole sections for production casing in some of the first wells of Phase 2 were drilled with conventional drillpipe until procedures for drilling with 4½-in. casing were established. The production sections of subsequent wells were drilled with a 6¼-in. PDC bit attached to the end of casing by a mechanical releasing device. This device also functioned as a near-bit stabilizer, a spacer joint, a crossover from casing connections to bit connections and a reaming shoe after the bit was released ([above](#)).

After reaching TD in wells that needed to be logged for formation evaluation, the bit was released by dropping a ball. The 4½-in. casing was backreamed and pulled up into the 7-in. casing to allow openhole wireline logging. After logging, a slickline-conveyed cementing float

valve was set at the bottom of the casing. This valve allowed cement to be pumped into the borehole annulus, but prevented it from backflowing, or U-tubing, into the casing. The casing then was reamed back to TD and cemented in place.

For wells that did not require openhole logging, a slickline-conveyed float valve was set in order to cement the casing in place through the bit. Nondrillable pump-down float valves are available for some pipe sizes, including 7-in. casing, and Tesco also has developed drillable pump-down float equipment. These cementing improvements allow casing and wellhead surface connections to proceed without having to wait for cement to set, which further minimizes nonproductive rig time.

The initial success of this technique reinforced the belief that drilling operations using casing can be performed without premature failure of tubular connections. During Phases 1 and 2, casing with buttress threads was used to drill surface and intermediate hole sections. A torque ring installed in each casing connection provided a torque stop and increased the torque capacity of the coupling.

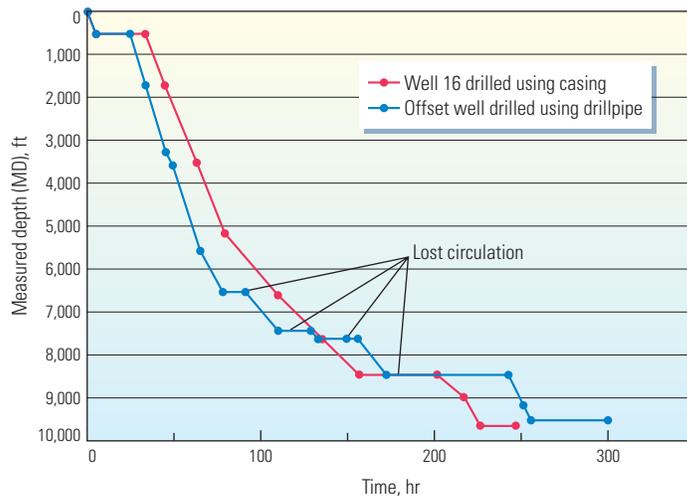
Manufacturers also are developing new casing connections that can handle higher torque. A special coupling, designed by Grant Prideco, was used for drilling operations with 4½-in. casing. ConocoPhillips now uses this coupling with 7-in. casing to drill intermediate hole sections. Surface-casing hole sections continue to be drilled using 9½-in. casing with buttress threads and a torque ring.

Casing while drilling has successfully minimized trouble time related to lost circulation and stuck pipe. The retrievable BHA has been extremely reliable during running and resetting at depths up to 9,000 ft [2,743 m]. Concerns about inclination control have been reduced through proper BHA design.

Two nearby offset wells in the Lobo program illustrated the benefits of drilling operations with casing. These wells did not require logs and were drilled within seven months of each other. A conventional rig operating in this area for more than four years drilled the first well. The second well was the fifteenth and, at that time, the fastest well drilled using casing and a Tesco Casing Drilling rig. Excluding rig repair time on both wells, the conventional well took 300 hours from start to rig release; the well drilled with casing took 247.5 hours, a 17.5% reduction in drilling time ([next page, top](#)).

The penetration rate for conventional drilling was slightly faster than for casing while drilling. However, the well drilled with casing experienced only slight lost returns, and drilling was able to continue after fluid losses stopped. Total downtime resulting from lost circulation was less than an hour. In contrast, the conventional well was plagued by fluid losses from about 6,500 ft [1,981 m] to the intermediate casing point at about 9,500 ft and required an additional 53 hours to deal with four lost-circulation events.

Drilling operations with casing included only 66 hours of nonproductive rig time at intermediate and production casing points compared with 113.5 hours for the conventional well. Neither well encountered significant problems during drilling operations, so this



^ Drilling time versus depth for conventional drilling and casing while drilling. The rate of penetration (ROP) for the conventional well (blue) was slightly faster than for casing while drilling (red), but operations were plagued by lost circulation from about 6,500 ft to the intermediate casing point at about 9,500 ft.



^ A more compact drilling rig. Tesco Casing Drilling® rigs were designed on standard oilfield skids, so the entire rig can be moved in 12 loads rather than the 23 loads required for conventional rigs. The most modern conventional rigs used in the Lobo development area require about 33 truckloads to make a move, with move time averaging about 2.2 days. The new rigs can be moved with standard oilfield winch trucks without the use of a crane. A rig move requires 12 hours from release to start of the next well.

difference reflected the relative efficiency of these two methods at the casing points. However, about 17 hours were lost waiting for cement to set on the well drilled with casing. As improved pump-down float devices for all casing sizes became available, this cementing downtime also was reduced.

Penetration rates also have improved with experience, reducing drilling time by another 30 hours. Tests are under way to understand the lower rate of penetration (ROP) with casing, which should help drillers increase casing penetration rates to equal or exceed those of

conventional drillpipe. Implementing an effective solution to these two problems could cut total drilling time for a 9,500-ft well to about 200 hours, a 33% reduction from the previous 300 hours.

In Phase 3 of this program, ConocoPhillips mobilized three new Tesco Casing Drilling rigs built specifically to drill in the Lobo trend (bottom left). These compact units include a topdrive to handle larger derrick loads and an automated power catwalk system that transfers casing to the rig floor. They also offer increased fuel efficiency and require a smaller surface pad, or footprint. The small, mobile Casing Drilling rigs have a depth rating of 15,000 ft [4,572 m] and were designed for optimal drilling operations with casing, but also can use conventional drillpipe.

During the past five years, ConocoPhillips has drilled more than 350 intervals and about 1,050,000 ft [320,040 m] in 110 wells using retrievable drilling systems for casing. Collectively, experience in these wells confirmed that casing while drilling could eliminate or reduce lost circulation and other problems associated with depleted zones.

Initially drillers expected lost circulation to be a problem when using casing to drill because of the increase in equivalent circulating density (ECD). A higher ECD results from the smaller annular clearance between large casing and the borehole wall, which increases frictional pressure losses. The exact mechanism during casing while drilling that mitigates lost circulation is not clearly understood at this time, but combined with a higher ECD, it allows lower mud weights to be used, which may facilitate air drilling and underbalanced drilling.

During all three phases of this Lobo development project and other applications of casing while drilling, no significant or serious lost-circulation events have occurred. Even in areas near conventionally drilled wells that previously required multiple remedial cement plugs and additional unscheduled full-length liners to reach TD, there were fewer lost-circulation problems and fewer incidents of stuck pipe.¹²

This ConocoPhillips work established the reliability of a retrievable drilling BHA and hinted at potential future applications for casing while drilling. Several operators are pursuing applications for this technique in areas where conventional drilling costs are high. In these applications, improvements in operational efficiency would provide an even greater economic impact.

12. Fontenot et al, reference 11.

Increasing emphasis on redeveloping mature offshore properties in which high-angle wells must traverse pressure-depleted zones offers an excellent opportunity to drill directionally with casing and realize significant cost savings.

However, only about 34,000 ft [10,363 m] in 12 well intervals have been drilled directionally using a steerable PDM or an RSS in a retrievable BHA. These operations with 7-in. and 9 $\frac{5}{8}$ -in.

casing demonstrated the viability of casing directional drilling, but also highlighted the limitations of steerable motors ([below](#)).

Steerable Downhole Motors

Drilling with casing and steerable motors in test wells and actual field operations identified three limitations—BHA geometry, motor performance and operational practices. In a retrievable BHA

for casing, the PDM and bent housing are placed above the underreamer and pilot bit to rotate both. This configuration allows slide drilling without rotating the entire string to make directional corrections. As a result, the BHA geometry for directional control with steerable motors and casing differs from a conventional BHA for drillpipe ([bottom left](#)).¹³

In addition, drilling systems for casing directional drilling must pass through the casing, so the entire BHA and the PDM are smaller relative to the hole size. This limits the motor bend angle. The bent housing contact pad often does not touch the borehole wall. Instead, a pilot-hole stabilizer is incorporated below the underreamer cutters to provide directional control and ensure a smooth borehole trajectory.

Smaller motors and components also increase BHA flexibility, so maintaining directional control is more difficult. The entire assembly is tilted at a greater angle in the borehole and has a tendency to build inclination angle, which makes dropping borehole angle more difficult. Adding an expandable stabilizer or an underreamer with noncutting stabilizer pads above the motor reduces rotating build rates and provides the capability of dropping inclination angle by sliding, but this makes the BHA more complex.

Another inefficiency arises when PDM torque reaches higher levels and the circulating pressure increases, causing the drillstring to elongate. Because the bit is on bottom and the casing cannot move downward, both the weight on bit (WOB) and the required rotational motor torque increase, further exacerbating the increase in circulating pressure.¹⁴

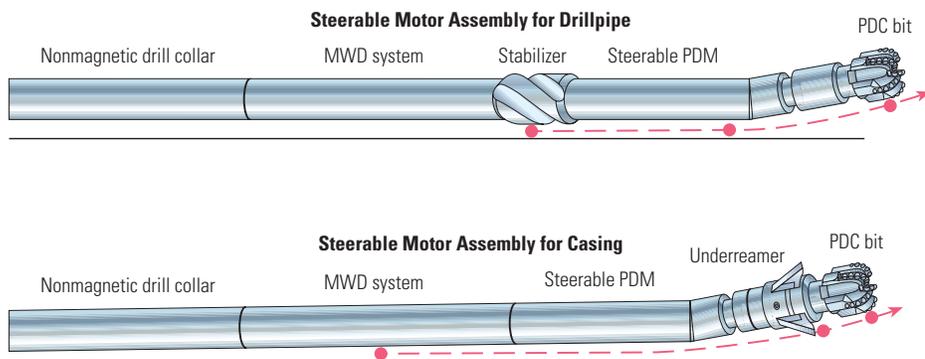
This effect is cyclic and causes motors to slow down and stop, or stall. The problem worsens with casing, which tends to lengthen more under internal pressure than does conventional drillpipe. For a given internal pressure increase, the additional WOB for 7-in. casing is about six times greater than for 3 $\frac{1}{2}$ -in. drillpipe with the same size motor.

In deeper wells and under conditions of high borehole friction, increased WOB may be difficult to detect at the surface. As a result, a PDM may stall before drillers can take corrective action. The consequence is that smaller, less powerful motors that are required for casing while drilling may have to be operated at less than optimal torque and pressure to compensate for abrupt WOB changes.

The primary issue with smaller motors is a relative lack of power compared with larger versions. Selection of the most appropriate motor for directional drilling is critical, particularly for

Commercial Directional Wells Drilled with Casing							
Well	Casing size, in.	Initial depth, ft	Distance drilled, ft	Maximum inclination, degrees	Build rate, degrees/100 ft	Type of application	Type of BHA
1	9 $\frac{5}{8}$	339	2,993	4	2	Avoid collision	PDM
2	9 $\frac{5}{8}$	370	3,468	4	2	Avoid collision	PDM
3	7	6,000	705	8	1.5	Build angle and hold	PDM
4	9 $\frac{5}{8}$	393	2,247	40	3	Build angle and hold	PDM
5	9 $\frac{5}{8}$	393	3,172	17	1.5	Build angle and hold	PDM
6	9 $\frac{5}{8}$	492	1,968	16	1.5	Build angle and hold	PDM
7	7	2,115	4,418	16	—	Drill tangent	PDM
8	9 $\frac{5}{8}$	633	2,739	17	2	Vertical and build angle	PDM
9	7	4,434	3,427	15	2.5	S profile	PDM
10	7	1,278	4,672	29	2.5	S profile	RSS
11	9 $\frac{5}{8}$	8,987	1,118	80	1.5 build 1.5 turn	Build angle and turn	PDM
12	7	5,007	2,843	25	3	S profile	RSS and PDM

Commercial directional wells drilled with casing. In its first commercial application, casing directional drilling was used to drill surface holes to 3,332 ft [1,016 m] and 3,838 ft [1,170 m] with 9 $\frac{5}{8}$ -in. casing for two offshore wells—Wells 1 and 2, respectively. The most extensive commercial drilling using casing was conducted in Mexico, where 9 $\frac{5}{8}$ -in. casing was used to kick off and build inclination for intermediate hole sections in three wells—Wells 4, 5 and 6—drilled from a central surface pad onshore.



Directional drilling geometry and control points. In a conventional directional BHA for drillpipe, three distinct points—the bit, a stabilizer pad on the motor bend and a stabilizer above the motor—define the geometry for building inclination angle (*top*). The upper two points are noncutting, so the geometry and stiffness of the BHA force the bit to cut along a circular path. In casing directional drilling, three points also determine the build rate for a steerable motor, but the points are not as defined and are more difficult to modify (*bottom*). The lower point is still the bit, but the second point is not located at the motor bend. A smaller motor relative to the hole size must be used to pass through the casing in a retrievable assembly. As a result, the motor bend often does not contact the borehole wall. Instead, a rotating, noncutting stabilizer below the underreamer cutter pads functions as the second control point. Directional control may be affected because the bit is farther away from the upper control point.

7-in. and smaller casing sizes. Low-speed motors with more torque output in response to increased pressure are easier to operate. A bit with less aggressive cutting structures that do not cut as deeply into the formation also improves motor performance. All of these factors, however, reduce drilling efficiency and penetration rates.

For casing larger than 9% in., motor power considerations are less critical because larger motors relative to hole size can be used. In some cases, it may be advantageous to use motors specifically designed for casing directional drilling that provide high torque at relatively low pumping pressure.

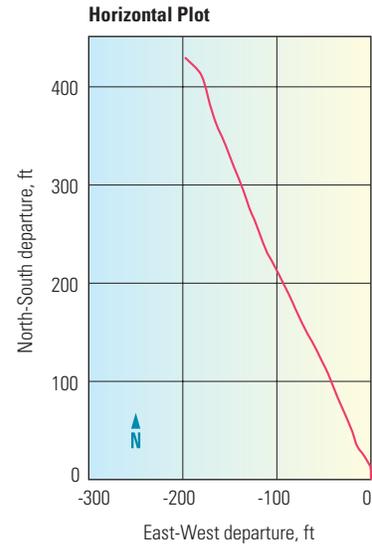
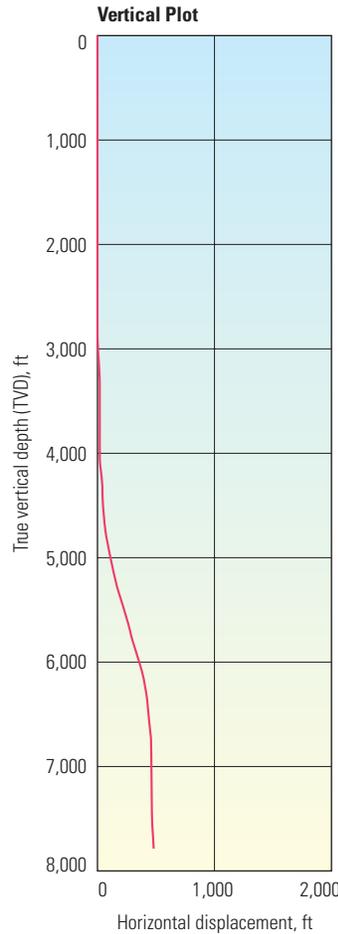
Recovering from motor stalls and reorientating a BHA require less time with casing because casing is stiffer than drillpipe. The casing does not twist as much between the surface and a PDM, so there is no need to reciprocate casing to relax this stored torque. The WOB is allowed to drill off without lowering the casing. The BHA then is picked up slightly and rotated to the desired orientation. If a motor stalls, the pump rate is reduced and the string is picked up to restart the motor, usually without having to readjust the bend angle of the motor.

If borehole friction causes the casing to hang up, manually or automatically rocking, or rotating, the entire string forward and reverse, without changing the BHA orientation helps control abrupt changes in WOB when sliding. This allows the motor to run more consistently and improves drilling performance without affecting directional control.¹⁵

PDM limitations and the potential benefits of using rotary steerable technology were evident in south Texas drilling operations with casing. ConocoPhillips drilled two wells in the Lobo trend using a retrievable BHA with a PDM for vertical inclination control. Two other Lobo wells were directionally drilled with casing using steerable motors in a retrievable BHA.

Lobo Well 83 included an interval that was directionally drilled with 7-in. casing because of a surface obstruction. The planned S-shape trajectory called for building inclination to about 15° and then dropping angle back to near vertical after achieving sufficient lateral displacement to reach the subsurface target (above right).¹⁶

This well was drilled vertically to the kickoff point at 4,434 ft [1,351 m], where the straight drilling assembly was retrieved by wireline and replaced with a directional BHA that included a 4% in. PDM. Drilling operations required intermittent slide drilling from the kickoff point to 4,808 ft [1,465 m] to build angle and establish the desired direction.



^ Lobo Well 83 vertical and horizontal trajectory plots. To avoid a surface obstruction, Lobo Well 83 was drilled with an S-shape trajectory. This borehole was drilled vertically to the kickoff point at 4,434 ft before building inclination angle to about 15° and then dropping back to a near-vertical inclination after achieving about 500 ft of lateral displacement.

13. Warren T and Lesso B: "Casing Directional Drilling," paper AADE-05-NTCE-48, presented at the American Association of Drilling Engineers (AADE) National Technical Conference and Exhibition, Houston, April 5-7, 2005.

Warren T and Lesso B: "Casing Drilling Directional Wells," paper OTC 17453, presented at the Offshore Technology Conference, Houston, May 2-5, 2005.

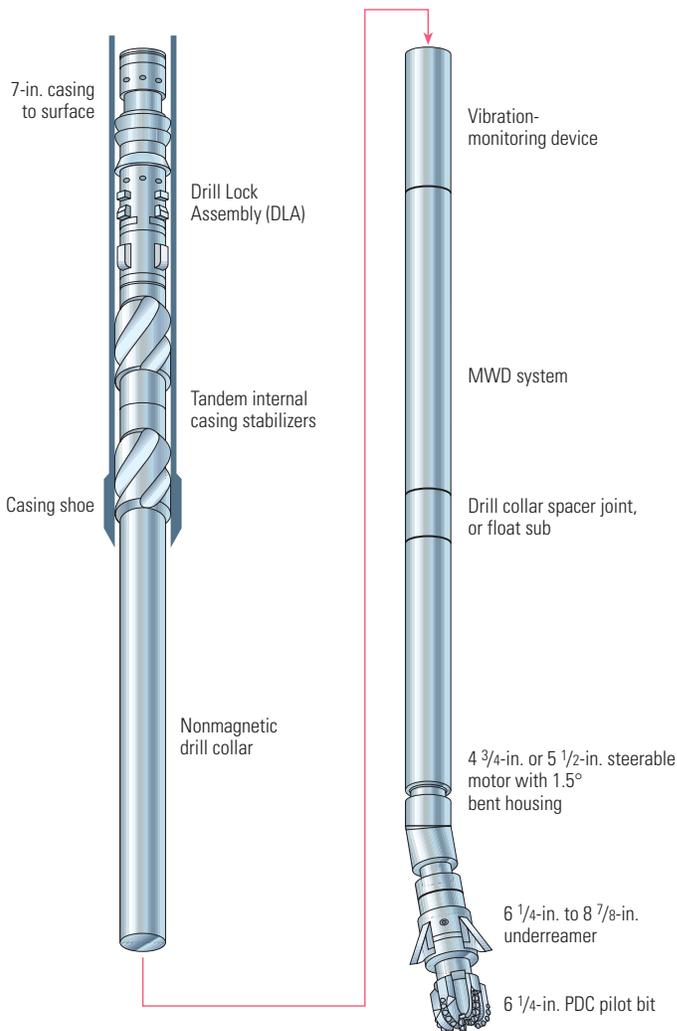
14. Warren et al, 2000, reference 9.

15. Maidla E, Haci M, Jones S, Cluchey M, Alexander M and Warren T: "Field Proof of the New Sliding Technology for Directional Drilling," paper SPE/IADC 92558, presented

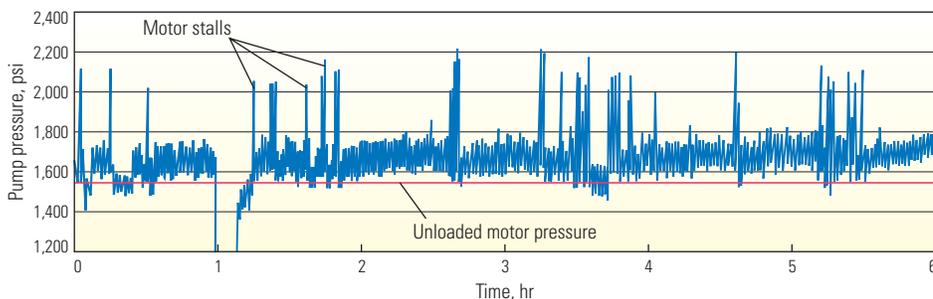
at the SPE/IADC Drilling Conference and Exhibition, Amsterdam, February 23-25, 2005.

Plácido JCR, Medeiros F, Lucena H, Medeiros JCM, Costa VASR, Silva PRC, Gravina CC, Alves R and Warren T: "Casing Drilling—Experience in Brazil," paper OTC 17141, presented at the Offshore Technology Conference, Houston, May 2-5, 2005.

16. Strickler R, Mushovic T, Warren T and Lesso B: "Casing Directional Drilling Using a Rotary Steerable System," paper SPE/IADC 92195, presented at the SPE/IADC Drilling Conference and Exhibition, Amsterdam, February 23-25, 2005.



▲ Lobo Well 83 retrievable BHA for a steerable downhole motor. The BHA for drilling a directional interval with 7-in. casing in Lobo Well 83 included tandem stabilizers inside the casing to reduce vibrations and wear on the DLA, a nonmagnetic drill collar, a vibration monitor, an MWD system, a spacer, or float, joint and a 4 3/4-in. motor with a 1.5° bent housing. The assembly ended in an underreamer that opens up to 8 7/8 in. and a 6 1/4-in. polycrystalline diamond compact (PDC) pilot bit.



▲ Lobo Well 83 downhole motor performance. Slide drilling without full string rotation resulted in frequent stalls during casing directional drilling with a steerable motor in Lobo Well 83.

The 4 3/4-in. steerable motor ran for only 154 ft [47 m] before being replaced with a 5 1/2-in. motor that generated higher torque at lower pressures and speeds (left).

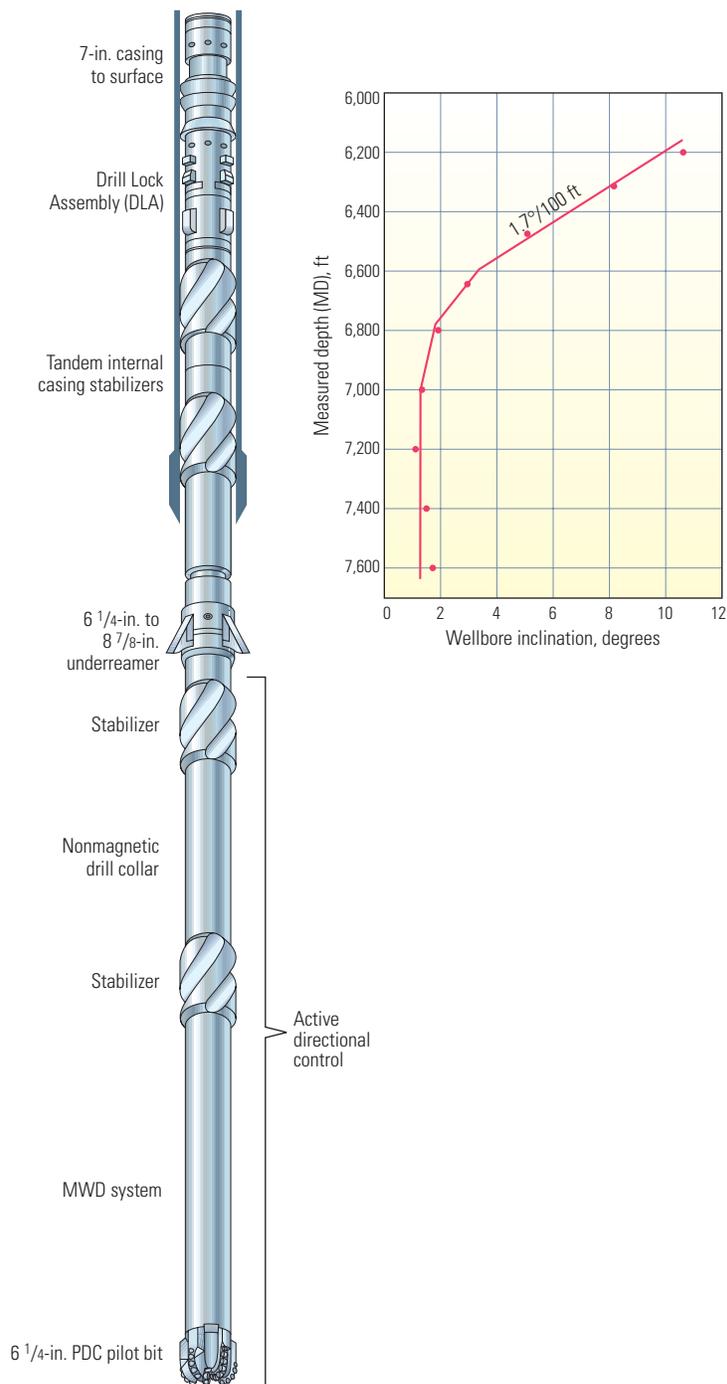
When borehole angle reached about 10°, the well was drilled in rotating mode, which increased the inclination angle to 15°. The borehole inclination could be increased easily, but dropping angle required continuous sliding. Slide drilling was reinitiated at 5,634 ft [1,717 m] to return the trajectory closer to vertical. Even after switching to the larger PDM, a significant number of stalls occurred, which required that the motor be run at lower speeds and torque loads during sliding (bottom left).

Recovering from stalls while drilling with casing was quicker than with drillpipe. The casing was sufficiently stiff, so reorientation was not required. The bit was simply picked up to restart the motor and then worked back to bottom to continue drilling. Slide drilling without full string rotation significantly reduced the ROP, confirming PDM limitations reported in other wells.¹⁷

After the borehole inclination reached 10° again, the steerable motor assembly was pulled and replaced with a rotary BHA. This pendulum BHA was configured with the underreamer immediately outside the casing and the directional control portion in the pilot hole. Drilling with this assembly decreased the borehole angle from 10° to less than 2° of inclination, which was maintained until the assembly was pulled at 7,861 ft [2,396 m] (next page).

The ROP was substantially higher while rotary drilling, even when limiting the WOB to ensure that borehole inclination decreased as desired. A downhole vibration-monitoring device recorded high lateral vibration while drilling with this assembly, but relatively few motor stalls occurred while drilling in rotary mode, and the ROP improved significantly.

The directional performance of this rotary assembly confirmed that borehole inclination could be controlled in a small pilot hole even with the underreamer at a considerable distance above the active portion of the BHA. This test established confidence that RSS technology could be used to drill with casing. Currently, however, there are no RSS tools that can work above an underreamer.



▲ Lobo Well 83 pendulum assembly and rotary drilling performance. After reducing the inclination angle of Well 83 from 15° back to 10°, the steerable motor assembly was replaced by a pendulum assembly (left). This second BHA with two stabilizers between the pilot bit and the underreamer, which was positioned immediately below the casing, completed the drop in borehole angle back to near vertical. With the directional-control, or active, portion of the BHA in the pilot hole, the driller was able to decrease the inclination angle from 10° to less than 2° (right). This directional performance confirmed that well inclination could be controlled in the pilot hole while the underreamer enlarged the main hole at a considerable distance above the active part of the BHA. In addition, the ROP increased significantly while drilling in rotary mode with this assembly.

Directional operations with casing and a steerable PDM, especially in smaller hole sizes, are not efficient. It is easier to build inclination than to drop angle with a smaller motor and BHA. Even with drillpipe, orienting a PDM for a directional correction can take several hours at depths of 25,000 ft [7,620 m] or more. In addition to numerous stalls, the ROP generally decreases when using motors.

Using a steerable PDM demonstrated that it is possible to drill directional wells with casing, but drilling efficiency during these trials was not competitive with newer rotary steerable technology, which now is used in about 60% of directional wells drilled offshore.

Rotary Steerable Systems

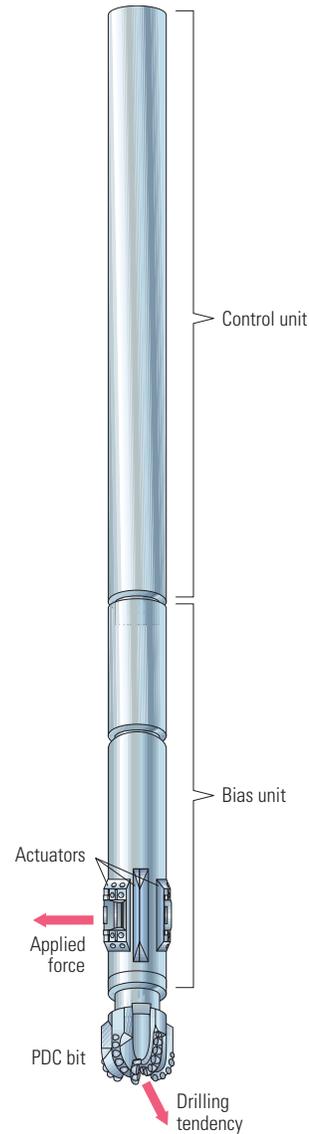
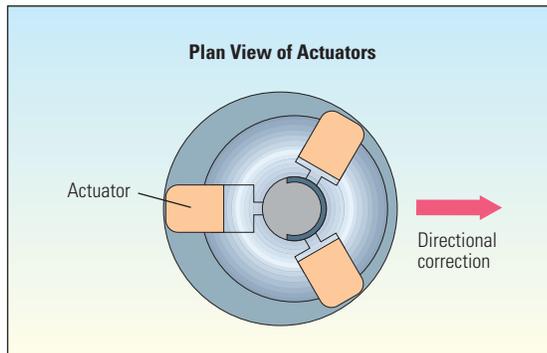
Success in reducing lost circulation during the Lobo drilling program sparked interest in applying casing while drilling offshore, where directional wells are a necessity. However, the limitations of drilling directionally with casing and steerable motors posed a problem. Rotary steerable technology, developed to drill directional, high-angle, horizontal and extended-reach wells, appeared to be a viable alternative.

In many situations, rotary drilling with a RSS is more efficient than using a downhole motor, even for vertical, straight-hole applications. Directional drilling with RSS technology eliminates orientation without rotation, or slide drilling, making it possible to drill record-breaking distances, such as the extended-reach wells in Wytch Farm field, UK, that are difficult to drill with downhole motors.¹⁸

As RSS systems became more durable and more reliable, they were deployed under increasingly demanding conditions offshore. Initially, RSS tools were applied primarily in deepwater wells. However, as RSS efficiency improved and their performance became better known, costs decreased and companies converted from steerable motors to RSS technology for directional operations, especially in the North Sea and the Gulf of Mexico.

17. Warren T, Tessari R and Houtchens B: "Directional Casing while Drilling," paper WOOD-0430-01, presented at the World Oil Casing Drilling Technical Conference, Houston, March 30–31, 2004.

18. Meader T, Allen F and Riley G: "To the Limit and Beyond—The Secret of World-Class Extended-Reach Drilling Performance at Wytch Farm," paper IADC/SPE 59204, presented at the IADC/SPE Drilling Conference and Exhibition, New Orleans, February 23–25, 2000.



^ Rotary steerable technology. A rotary steerable system (RSS) applies force against the borehole wall during full rotation of the entire drillstring to achieve a desired borehole trajectory. The PowerDrive Xtra system, for example, comprises a control unit that houses electronics and sensors (*right*). Based on commands from the control unit, the bias unit sequentially actuates three external pads, which apply force against the borehole wall at the appropriate point during each rotation to direct the bit in the required direction (*bottom left*). In vertical mode, this RSS tool senses deviation away from vertical and automatically thrusts the bit back to vertical. Several PowerDrive systems are available for drilling 4½- to 18¼-in. holes.

A rotary steerable system is ideal for directional control in the retrievable BHA used for drilling operations with casing. It minimizes or eliminates many of the problems associated with slide drilling, PDM performance limitations and directional control difficulties, while providing a smooth borehole that reduces torque. Compact and mechanically uncomplicated RSS tools are available for use in casing while drilling (*above*).¹⁹

PowerDrive systems incorporate a bias unit and a control unit in a 12.5-ft [3.8-m] housing. The bias unit, located directly above the bit,

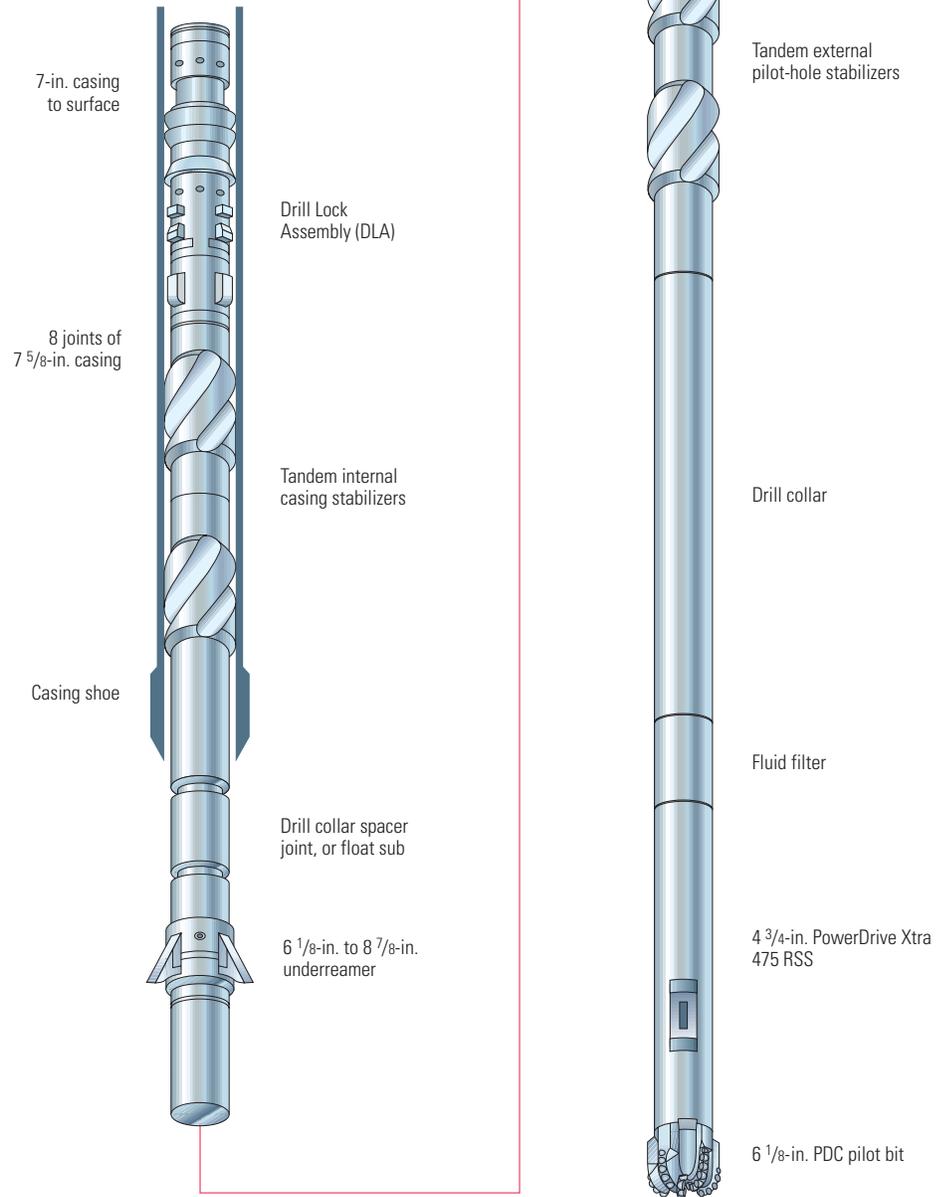
applies force in a controlled direction while the entire drillstring is rotated from the surface. The control unit, positioned behind the bias unit, contains self-powered electronics, sensors and a mechanism that applies a lateral force in the specified direction required to achieve a desired trajectory. The bias unit has three external, hinged pads activated by controlled mud flow.

A three-way rotary disk valve sequentially diverts mud into the piston chamber of each pad as it rotates into proper alignment to apply force in the direction opposite a desired trajectory. The bit is constantly moved in one direction. If a change in direction is not required, the system

operates in neutral mode, with each pad extending sequentially to effectively push in all directions and cancel each other.

During 2004, the Upstream Technology and Lower 48 Exploration and Production groups at ConocoPhillips began evaluating the feasibility of using RSS tools in the pilot hole below the underreamer for drilling operations with casing.²⁰ This project represented the first use of RSS technology for casing directional drilling. The challenge, however, was that there was little overlap in logistics and methodologies for merging casing while drilling with RSS technology.

Total length	94 ft [29 m]
Extension length	67 ft [20 m]
Weight in drilling fluid	5,200 lbm [2,359 kg]



> Lobo Well 89 retrievable BHA for vertical inclination control. Vertical drilling operations with 7-in. casing required a RSS assembly with tandem stabilizers inside the casing to dampen drilling vibrations and to reduce wear and tear on the DLA. A drill collar, or spacer sub, positioned the underreamer outside the casing. External 6¹/₈-in. stabilizers below the underreamer reduced drilling vibrations in the pilot hole. A PowerDrive Xtra RSS with a PDC bit completed the BHA.

ConocoPhillips, Tesco and Schlumberger conducted a two-well RSS test in the south Texas Lobo trend using PowerDrive technology. The first RSS test with casing was conducted in a vertical well. The second well was drilled directionally with casing and a RSS.

Rotary Steerable Vertical Test

In June 2004, ConocoPhillips, Schlumberger and Tesco performed the vertical RSS drilling test with casing in Well 89, located about 30 miles [48 km] northeast of Laredo, Texas. The vertical section for surface casing was drilled to 588 ft [179 m] using 9³/₈-in. casing and a retrievable BHA with an 8¹/₂-in. pilot bit and a 12¹/₂-in. underreamer.

A review of 7-in. casing designs for drilling vertical wells found that running heavyweight 7⁷/₈-in. integral flush-joint casing without centralizers as the bottom eight joints reduced drilling vibrations and fatigue failures. In addition, engineers found that connections with a beveled lower edge also reduced casing vibration and wear.

After the surface casing was cemented in place, a 4³/₄-in. PowerDrive Xtra 475 RSS programmed to maintain a vertical borehole and a 4³/₄-in. drill collar were added to the standard BHA for 7-in. casing (above). This retrievable

19. Kuyken C: "Rotary Steerable Technology: Pushing the Limit," *Oilfield Review* 16, no. 4 (Winter 2004): 1.
Coperchini P, Soliman F, Gamal ME, Longstreet W, Rodd J, Sarssam M, McCourt I, Persad B and Williams M: "Powering Up to Drill Down," *Oilfield Review* 16, no. 4 (Winter 2004): 4-9.
Brusco G, Lewis P and Williams M: "Drilling Straight Down," *Oilfield Review* 16, no. 3 (Autumn 2004): 14-17.
Williams M: "Better Turns for Rotary Steerable Drilling," *Oilfield Review* 16, no. 1 (Spring 2004): 4-9.
Downton G, Hendricks A, Klausen TS and Pafitis D: "New Directions in Rotary Steerable Drilling," *Oilfield Review* 12, no. 1 (Spring 2000): 18-29.
20. Strickler et al, reference 16.

BHA drilled to 4,821 ft [1,469 m] in 105 hours. Single-shot surveys taken every 500 ft indicated a near-vertical borehole inclination. Drilling proceeded without problems, but engineers attributed higher than expected vibrations to the long BHA extension.

This run terminated at a planned underreamer replacement. Drilling operations continued to the 7-in. casing point at 7,620 ft [2,323 m]. ConocoPhillips retrieved the BHA, which was inspected and found to be in good condition, and extracted operational data from the RSS tool. A multishot gyroscope run confirmed that the PowerDrive tool could maintain verticality (below left).

The vertical test confirmed RSS functionality and directional performance in a retrievable assembly, and led to approval for a second test. In the next well, a more advanced BHA with an MWD system and full directional capabilities would be used to follow a planned trajectory.

Inability to drill directionally or encountering significant problems would require that

ConocoPhillips switch back to drilling with drillpipe and a conventional BHA at considerable additional expense. This dictated careful design, planning and implementation of the second test to fully evaluate casing directional drilling with a RSS.

Rotary Steerable Directional Test

Most wells in the Lobo development area are vertical. In late 2004, however, Well 91 presented a unique opportunity. The proposed location was about 1,200 ft [366 m] south of Well 79, a vertical well that had been drilled with casing in March 2004. The ConocoPhillips teams proposed using the existing surface location of Well 79 to directionally drill an S-shape trajectory with casing to reach the subsurface target for Well 91.

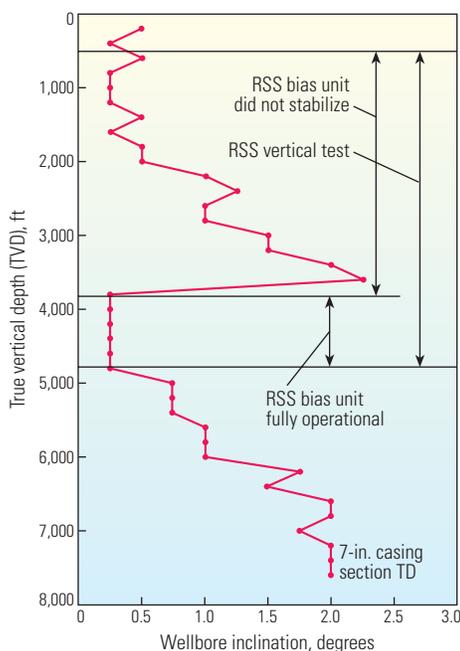
This plan avoided building another location, but the expense of directional operations was more than three times the cost of a new rig pad. ConocoPhillips planned no other directional wells for 2004, so this was the best option for testing casing directional drilling with a RSS.

The initial well plan called for building inclination angle to 29° and then dropping vertically into the target.

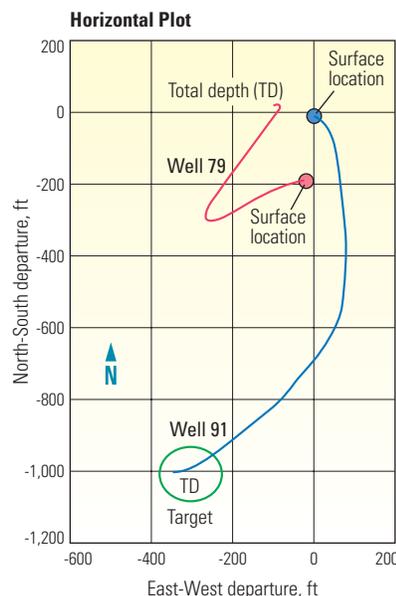
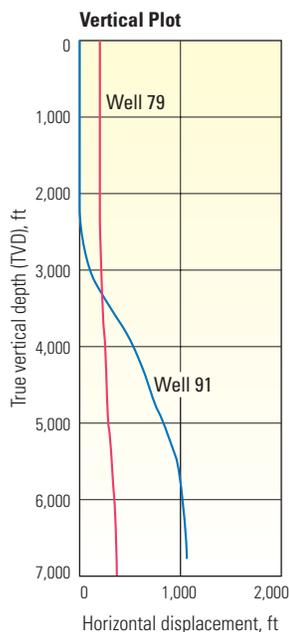
Unfortunately, wellhead and surface facilities for Well 79 were located between the remaining open space for a rig and the subsurface target of Well 91. A new trajectory was designed to avoid colliding with the existing wellbore. This profile resembled well trajectories common on multiwell offshore platforms (below right).

Another factor complicated drilling operations. Well specifications called for surface casing to be set at 1,270 ft [387 m]. The 9-in. casing point for Lobo wells varies between 550 and 2,400 ft [168 and 732 m], but experience indicates that wells with deeper surface casing have more problems with casing vibration and bit instability, or whirl, during drilling of the 7-in. casing section because of casing-on-casing friction inside longer surface sections.

Adding a straight PDM above the underreamer addressed this problem, but represented a significant change from the

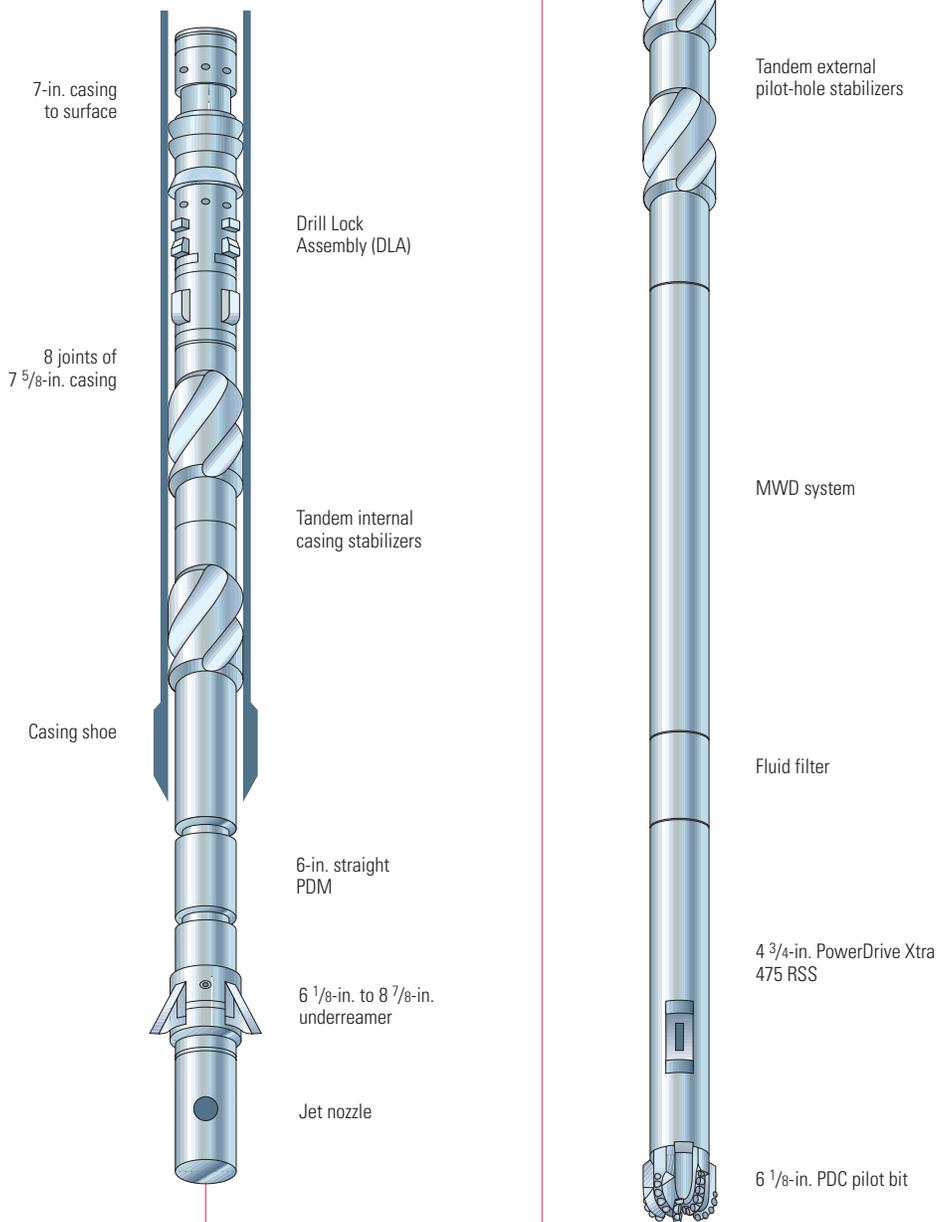


^ Gyroscope survey for the 7-in. casing section in Lobo Well 89. Inclination data from Lobo Well 89 indicated that the 4¾-in. PowerDrive Xtra 475 control unit did not stabilize on a gravity reference until the bit reached 3,710 ft [1,131 m]. The well drifted to an inclination angle of 2.25° at 3,600 ft [1,097 m]. The RSS regained full function and directional control from 3,710 to 4,821 ft. At 3,800 ft [1,158 m], the borehole trajectory returned to a near-vertical inclination of 0.25° for the remainder of the RSS vertical test. There was a slight tendency to build angle from about 2,000 ft [607 m] to 3,800 ft when the RSS tool was not effective and again after the test ended at 4,821 ft.



^ Lobo Well 91 vertical and horizontal trajectory plots. To avoid risk of a collision with Well 79, the horizontal trajectory of Well 91 started off along an azimuth 40° east of the target azimuth before beginning a 100° right turn to the southwest (right). The vertical trajectory built inclination angle to 29° (left). During later stages of the horizontal turn, drillers initiated a drop in angle to bring the borehole into the target at a near-vertical inclination. This profile resembled those used on large offshore platforms with multiple drilling slots.

Total length	112 ft [34 m]
Extension length	85 ft [26 m]
Weight in drilling fluid	6,200 lbm [2,812 kg]



< Lobo Well 91 retrievable BHA for rotary directional drilling. Directional operations with 7-in. casing and a RSS required several innovative BHA components. Tandem stabilizers inside the casing dampened drilling vibrations and helped protect the DLA. A straight 6-in. PDM served as a spacer sub and added rotation to the BHA and bit so that surface rotation of the drillstring could be decreased when dealing with high drilling vibrations. A jet nozzle below the underreamer diverted 20% of the drilling fluid from the bit to balance flow between the 6-in. pilot hole and the 8-in. main borehole. External 6-in. stabilizers in the pilot hole below the jet nozzle reduced vibration and wear on the underreamer. A slim MWD system and a PowerDrive Xtra RSS with a PDC bit completed the BHA.

vertical test in Well 89. The purpose of this motor was to allow reduced surface rotation of the drillstring when dealing with excessive vibrations. The motor also protected the drilling string and BHA by acting as a shock absorber. However, the MWD system had to be run below the motor, so the MWD signal had to travel up through the motor. This was technically feasible, but had never been done (above).

Casing directional drilling requires bit rotational speeds that are similar to drilling with

drillpipe, typically 120 to 180 rpm. The motor added rotation back into the BHA and bit to maintain an adequate ROP. For example, if bit whirl limits surface rotation to 50 rpm, the motor adds 100 rpm to reestablish optimal bit performance.

The underreamer, which opened the 6-in. pilot hole to 8-in., was placed directly below the mud motor. A jet nozzle diverted 20% of the drilling fluid from the bit to balance flow

between the pilot hole and the expanded borehole. Tandem 6-in. external stabilizers were positioned below the jet nozzle to reduce vibration and wear on the underreamer. A PowerDrive Xtra 475 RSS and a 6-in. PDC bit were installed below the MWD system.²¹

21. Downton GC and Carrington D: "Rotary Steerable Drilling System for the 6-in Hole," paper SPE/IADC 79922, presented at the SPE/IADC Drilling Conference, Amsterdam, February 19–21, 2003.

Drilling operations with 7-in. casing began at 1,278 ft [390 m]. A four-blade PDC bit with ¾-in. cutters was used to drill this section, the same type of bit used in other Lobo wells. Surveys indicated that the borehole was nearly vertical.

The MWD system located below mud motors maintained reliable data transmission. However, surveys had to be taken during quiet periods when rig pumps were off and there was no motor rotation, instead of when the pumps first came back on after a casing connection, which is common practice. Signal attenuation of MWD telemetry through the motor was only 40 to 50% instead of the expected 90%.

After the kickoff depth of 2,100 ft [640 m] was reached, the build section was completed as planned. The initial run continued to 4,067 ft [1,240 m], where pressure spikes indicated a problem, so the BHA was retrieved by wireline. The motor had locked up and there was a washout, or hole, in the RSS tool, but it was still operational. A PDM was not rerun. The bias unit of the RSS was replaced and drilling continued. Drilling was slower, and it was difficult to keep surface rotation above 60 rpm without the motor.

This second run ended when a replacement motor arrived on location. The motor was added back for the third run, restoring the BHA to the initial design configuration. Drilling proceeded for 200 ft [61 m] before the ROP dropped significantly. When the BHA was pulled, drillers found that the small stabilizer under the underreamer cutter pads was larger than the bit, 6½ in. instead of 6 in. This oversized stabilizer worked until harder formations were encountered.

The underreamer was replaced, and drilling continued without incident until reaching 5,420 ft [1,652 m], where the casing became differentially stuck. Directionally, the build and turn sections were completed, and the drop back to vertical was under way. Drilling continued to 6,360 ft [1,939 m]. The two instances of nonproductive time in directional Well 91, an oversize stabilizer and stuck pipe, added about 85 hours to the total drilling time.

The borehole was now at a 4° inclination angle. A pressure drop indicated a washout in the BHA. Surface inspection revealed a washout in the connection between the jet nozzle and the external tandem stabilizer. The jet nozzle was removed from the BHA and drilling continued to TD at 6,950 ft [2,118 m].

Using casing for drilling improves operational efficiency by eliminating pipe trips and reducing unexpected difficulties encountered when running casing in a separate operation. ConocoPhillips experience in Well 91 proved that RSS technology is effective for casing directional drilling in smaller 8½ to 9½-in. hole sizes where PDM performance is limited ([next page](#)).

Bit selection issues common in directional drilling with conventional drillpipe and a RSS must be addressed to drill directionally with casing. Bits are chosen based on their side-cutting capability for directional control and their stability to reduce excessive vibrations. Bit hydraulics and BHA nozzles also have to be balanced so that fluid flow rates in both the pilot hole and the full-gauge borehole remain within optimal ranges for effective bit and hole cleaning, and for operating MWD systems and PDM or RSS tools.

If the borehole surface is irregular or rough and the well path is tortuous, casing stiffness can contribute to higher torque. Lateral and torsional forces are higher than with drillpipe because larger tubulars weigh more and have a greater rotating diameter. Casing string designs for drilling directional wells require more centralization than in vertical wells.

In addition, casing centralization plays an important role in effective hole cleaning, and in reducing drillstring vibrations and incidents of pipe sticking. Hole cleaning and differential sticking increase in directional wells with higher inclination angles. Care must be taken to avoid long periods of time when either the casing or the BHA is stationary without fluid circulation.

Casing while drilling, and to a greater extent casing directional drilling, are still in early stages of development. Procedures and practices will be optimized as operator experience with these new technologies increases.

An Expanding Range of Applications

Operators in the USA and Canada have drilled commercial vertical wells with casing sizes ranging from 4½ in. to 13½ in. The deepest well drilled to date was just over 13,000 ft [3,959 m]. Directional wells have been drilled with casing and steerable motors, but success is difficult to achieve in hole sizes of less than 8½ in. because a smaller PDM supplies suboptimal torque for drilling.

Experience gained from vertical and directional testing of rotary steerable technology while drilling with casing proved that a 4½-in. RSS can effectively drill 8½-in. holes with 7-in. casing. Directional control in the pilot hole is sufficient to guide larger diameter underreamers

and casing to a directional target. Schlumberger is currently conducting field trials of a 3½-in. ultraslim RSS for drilling with 6-in., 5½-in. or 5-in. casing.

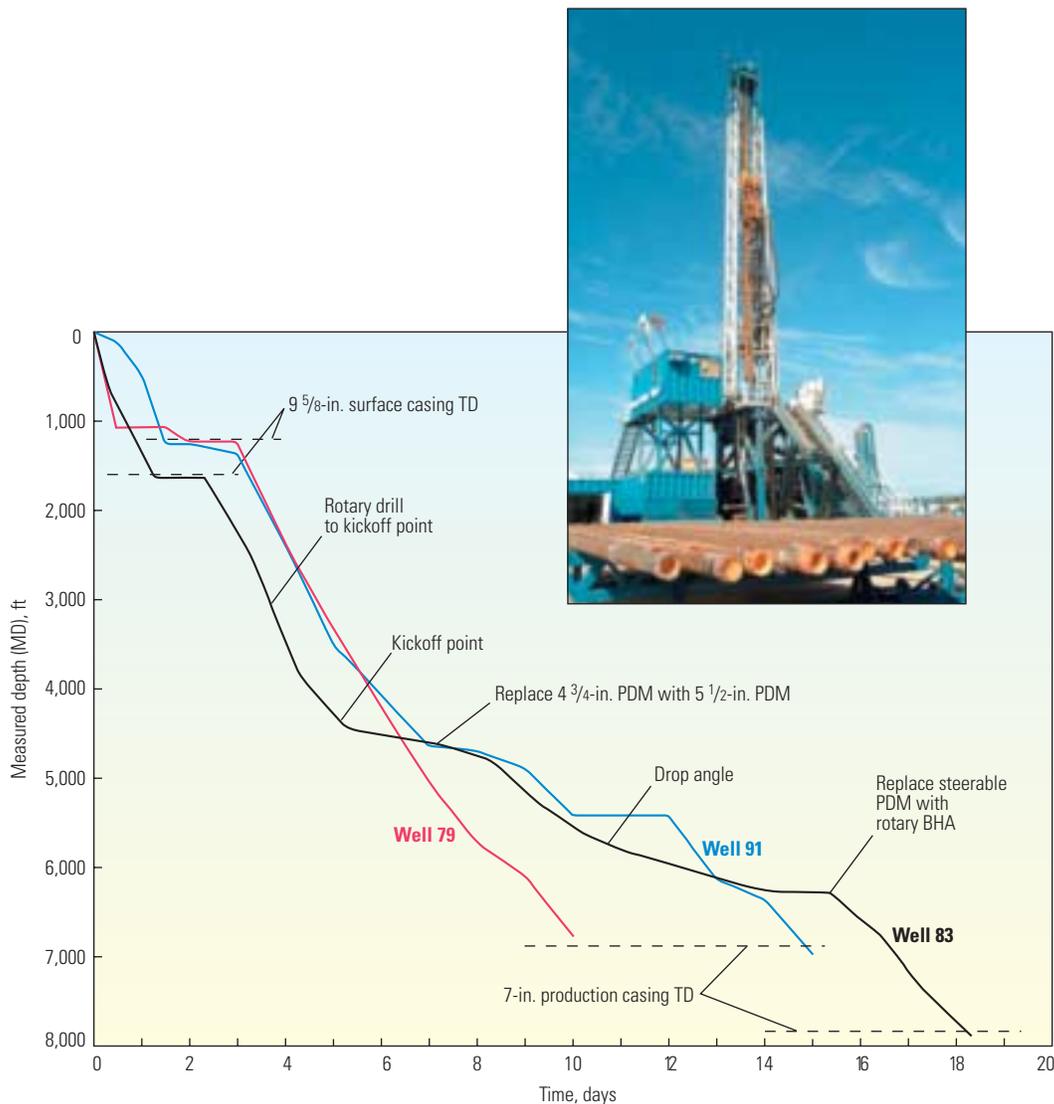
Acquiring well logs for formation evaluation is a key consideration when evaluating casing while drilling. Because casing remains in the wellbore after reaching TD, operators must identify the best methods for logging these wells to take full advantage of casing while drilling and its capabilities to reduce nonproductive rig time. Currently, there are four options: run conventional openhole wireline logs, run memory logging tools in a retrievable BHA, run an LWD system in the drilling BHA, or run new wireline logging systems that acquire measurements behind pipe.

To run openhole or memory logs, the casing must be pulled into the previously cemented casing. The casing has to be pulled above the zones of interest, but does not have to be tripped completely out of the well. If a kick occurs during logging, it can be circulated out down to the top of the openhole section. However, if the borehole collapses, it may not be possible to acquire a log across the entire interval.

Memory logs are acquired as the casing is pulled back into the preceding casing string by deploying logging tools in a retrievable BHA after retrieving the drilling assembly. This approach ensures that the entire openhole section can be logged and evaluated. Continuous fluid circulation keeps logging tools cool and reduces the chance of a kick during logging.

LWD tools have been used in vertical wells during drilling operations with casing, eliminating the need to pull casing before logging. However, the addition of LWD tools to a retrievable BHA adds cost, weight and length, which must be balanced against wireline retrieval risks and vibration problems in longer BHA extensions.

New technology now makes logging behind casing possible. Schlumberger ABC Analysis Behind Casing services are a cost-effective alternative to openhole, memory or LWD formation evaluation, allowing operators to minimize nonproductive rig time by assessing potentially productive intervals after reaching TD without pulling or manipulating the casing. In addition to acquiring resistivity, porosity, sonic, bulk density, lithology, pulsed neutron and reservoir pressure measurements behind cemented pipe, ABC services also include sampling of formation fluids.²²



▲ Drilling time versus depth for Lobo Well 91, Well 79 and Well 83. Directional Well 91 (blue) and nearby vertical Well 79 (red) were comparable over about 4,500 ft [1,372 m]. A total of 132 casing joints were used to drill directionally in Well 91 compared with 128 joints for vertical Well 79. The ROP on a joint-by-joint basis for the directional well was only about 10% less than the ROP in the vertical well. The trajectory was more complex in Well 91, but drilling with casing and a RSS saved a substantial amount of time compared with Well 83 (black), which was drilled using casing and a steerable PDM.

The capability of drilling directional wells makes casing while drilling attractive for offshore applications in areas prone to lost circulation and previously uneconomic to drill using conventional processes and techniques. Modifications of current systems are under way to allow casing while drilling in deepwater applications. Most deepwater casing strings are set as liners. Several strategies are under development to apply retrievable BHA experience to liner drilling.

There are several potential applications that require additional advances in equipment and techniques. Research and development are under way to allow underbalanced drilling using casing and drilling with air. An obvious advantage of using casing for air and underbalanced drilling is that wells do not have to be balanced with heavier mud, or killed, to trip drillpipe out of the hole.

In the future, this technique may be used to drill high-pressure, high-temperature (HPHT) and geothermal wells. The combination of casing while drilling and expandable tubulars ultimately may provide a unique well-construction solution, but additional hurdles must be overcome for this to be practical. As casing directional drilling becomes more common, market pressures will likely stimulate the development of additional systems and technologies specifically for use in casing-while-drilling applications. —MET

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