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Ultradeep Drilling Pushes Drillstring Technology Innovations

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Summary

Drilling ultradeep (UD) wells places significant requirements on the drillstring. Lengthy drillstrings lead to high tensile loads, which can lead to slip crushing of the drillstring; hoisting capacity issues; and drillpipe collapse capacity concerns at the blowout preventer (BOP). BOP shear rams may also have difficulty shearing today's high-strength, high-toughness drillpipe. Bottomhole assembly (BHA) connection failures pose greater risk and cost at UD well depths.

This paper analyzes the many challenges associated with drillstring designs specifically for UD drilling (UDD). It presents emerging drillstring technologies that are solutions expected to increase depth capability for the industry's continued advancement of deep-drilling operations.

Trend of Deep Total Vertical Depth (TVD) Drilling

Deep-drilling trends in the United States and throughout the world are increasing. Since 1995, the number of US wells drilled greater than a TVD of 15,000 ft has more than doubled (see **Fig. 1**). The number of annual, active U.S. rigs drilling greater than 15,000 ft TVD has nearly tripled (see **Fig. 2**) (Spears & Associates 2006). The number of high-pressure/ high-temperature (HP/HT) completions in the U.S. has nearly tripled since 2000 (Mayerhofer et al. 2005). US gas production from "deep" formations is also expected to double from 7% in 1999 to 14% by 2010 (Schlumberger Data 2005).

During late 2005, the Knotty Head well in Green Canyon Block 512 was drilled to a total depth (TD) of 34,189 ft, the Gulf of Mexico's (GOM) deepest well ever drilled (Discoverer Spirit). The 14¾-in.-hole section was drilled to 24,085 ft, and more than 4 million ft or approximately 775 miles (1,250 km) of drillpipe was tripped throughout the course of the well. The previous record well in the GOM was drilled earlier in the year to a TD of 32,727 ft (Discoverer Spirit 2005).

Many rig contractors are presently upgrading or building new jackup, semisubmersible, and dynamically-positioned drillship rigs capable of drilling to 35,000 ft (TD). One rig contractor recently contracted the manufacture of a USD 650 million dynamically-positioned drillship capable of drilling in 12,000 ft of water to well depths of 40,000 ft (Transocean 2006). Wells to these depths will require substantial investment and the advancement of facilitating technologies for UDD.

Extended Reach vs. UD TVD Drilling

Enabling technologies and innovative techniques have contributed significantly to the industry's current ability to reach significant well departure distances, which is evidenced throughout extended-reach (ER) projects around the world. Some of these technologies include (Payne et al. 1994, 1995a, 1995b; Jellison and Payne 2000; Payne and Bailey 1998):

- Use of sophisticated computer-drilling simulators
- Advancements in drilling-fluid technologies providing increased lubricity and improved cuttings transport, wellbore stability, and formation-damage resistance characteristics
- Drillstring and casing friction reducing tools
- Drillpipe high-torque tool joints and high-friction-factor thread compounds
- Intermediate drillpipe sizes such as 5⅞ in.
- Improved hole-cleaning procedures
- Casing-flotation and liner-rotation techniques
- Highly variable gauge stabilizers (H-VGSs) and rotary steerable systems (RSSs)
- Advancements in downhole-measurement tool capabilities such as the introduction of pressure while drilling (PWD) tools and improved surveying and logging technology
- Development and use of drillstring dynamics monitoring and mitigation systems
- New and improved rig and surface equipment

While these technologies have contributed successfully in pushing the ER envelope to increase recoverable reserves, significant obstacles remain when drilling UD and deep-directional wells of lower reach/TVD ratios generally not characterized as ER.

A key difference between ER drilling (ERD) and UDD is the mechanical loading that occurs within the drillstring. Generally speaking, ERD can be characterized as high torque and low tension, requiring focus on increasing the drillstring's ability to carry torque, addressing methods of reducing torque, upgrading the rig to provide higher torque, and overcoming drillpipe buckling issues. Considering these ER drillstring-loading characteristics, it is readily seen how the technologies listed have enabled the industry to reach the extreme departure distances it has (Smith et al. 2001).

UDD drillstring loading can be generally characterized as high tension and low to moderate torque. For purposes of definition, the authors define UDD as wells deeper than 25,000 ft TVD and reach/TVD ratios of less than 0.25. Wells of this type require focus on maximizing the drillstring's tension carrying capacity, reducing tensile loading of the drillstring, and outfitting the rig and its equipment (slips, elevators, top drive) to support higher drillstring tensile loads. Unlike the torque reduction challenges overcome for ER, overcoming high tensile loads on the drillstring may prove more challenging. This is largely because drillstring comprised mainly consisting of steel drillpipe of a set density (0.283 lbm/in.^{3}) and yield strength (135,000 psi). Because most challenging well types define the drillpipe size(s) on the basis of the hydraulic requirements of the well, a TVD limit exists for the well simply because of the tensile load limit of S-135 steel drillpipe (Smith et al. 2001). This, along with other challenging obstacles, has inhibited the industry's progress regarding wells of this nature as illustrated in **Fig. 3**.

Similar to the rewards gained by overcoming the obstacles of ER, operators have identified reserves that now require overcoming the challenges associated with UDD. Projects throughout the world have been identified and are in the planning stages, including multiple projects within deepwater and shelf GOM, deepwater west Africa, Brazil, Trinidad, and Malaysia, and UD gas-recovery projects beneath the Caspian Sea (Smith et al. 2001).

Advanced Material Technologies for UDD

Many industry publications have presented the idea of using nonsteel drillstrings primarily for the reduction of torque and drag loads within ER wells (Payne et al. 1995). However, other torque and drag reduction and management tools and techniques have proved successful, are lower cost, and are more practical, thus being the preferred method for meeting current ER torque and drag challenges and inhibiting the progress of developing commercially available nonsteel drillpipe (Smith et al. 2001).

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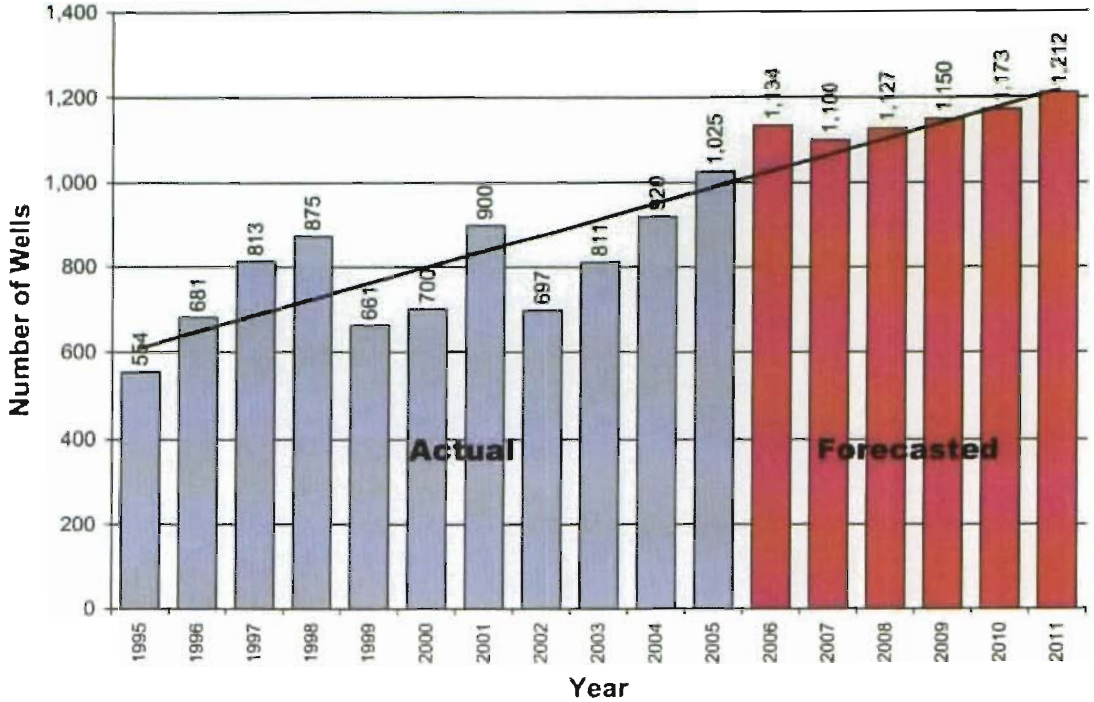

Fig. 1—Increasing trend of US wells drilled greater than 15,000 ft TVD. Since 1995, the number of wells has more than doubled (Spears 2006).

The recognition of future industry direction toward UDD, however, has led to increased consideration for commercially available nonsteel drillpipe. Any discussion of drillstem requirements for UDD would be incomplete without consideration of advanced material technologies and their potential future use for enabling deeper drilling objectives. Generally, three advanced materials should be included in this discussion: carbon-fiber-based composites, titanium, and aluminum. Each of these materials has been studied for use to manufacture drillpipe, and each has been employed in drillstrings with varying degrees of frequency and success. Each material has both strengths and weaknesses relating to its use for drillpipe to drill UD wells and other critical applications such as ER and deepwater. A discussion on the capabilities and potential for each of these material types follows.

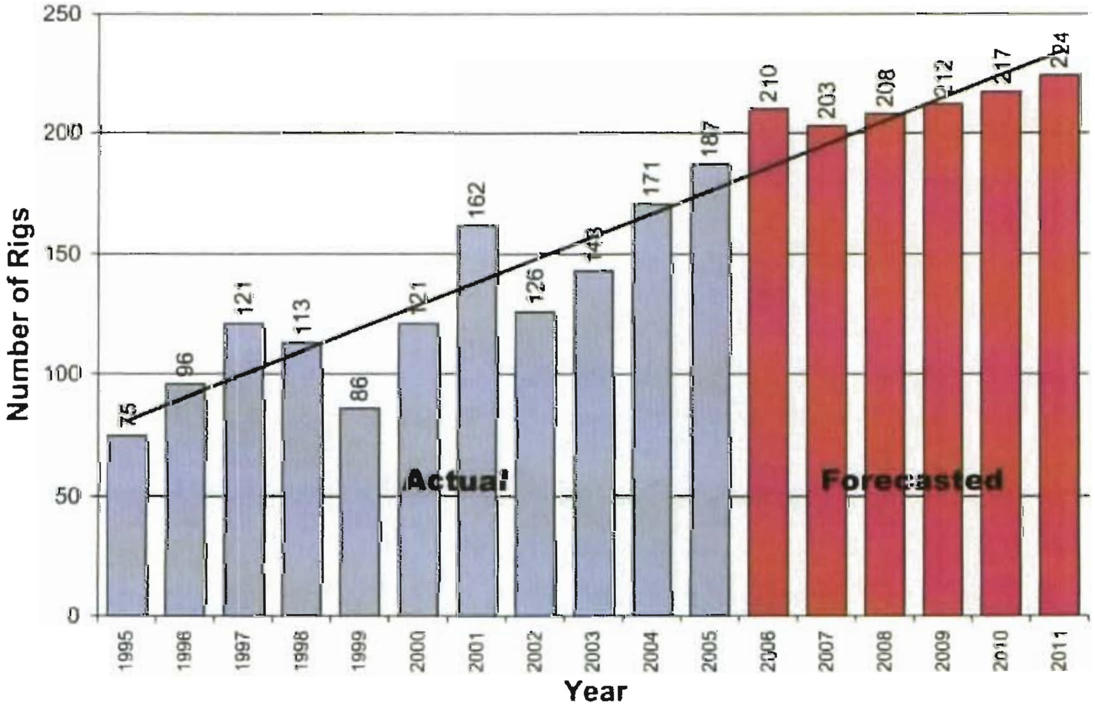

Fig. 2—Since 1995, the number of active US rigs working each year drilling wells greater than 15,000 ft TVD has nearly tripled (Spears 2006).

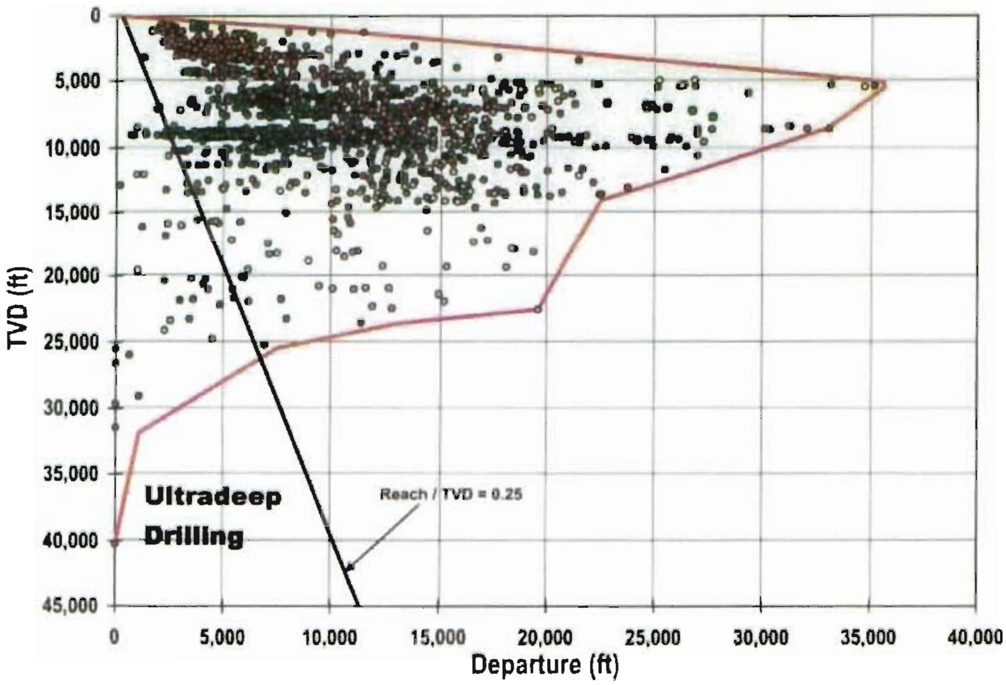

Fig. 3—Review of the industry ERD database shows strong ability to extend well departures, but reduced success in the ultradeep regions.

Carbon-Fiber-Based Composites. Composite drillpipe (CDP) is manufactured by winding carbon fibers over a mandrel while applying an epoxy matrix to encase the fibers and seal the assembly. CDP manufactured to date has incorporated steel pin and box-tool joints similar in design to conventional steel drillpipe connections. The steel-tool joints are attached to the composite tube during the winding process in which the carbon fibers are placed over specially designed ends of the tool-joint members to bond with the composite tube and resist fatigue damage in service. Currently produced composite drillpipe is approximately three times the cost of conventional steel drillpipe. As the technology improves and the capabilities of carbon fiber manufacturers advance, this price differential may decrease.

CDP offers several potential advantages over conventional steel drillpipe:

- Lower weight
- Higher strength to weight ratio
- Superior corrosion resistance (properly-designed composite material is essentially immune to corrosion)
- Enhanced resistance to fatigue
- Nonmagnetic properties

These advantages could make CDP particularly well suited to UDD and other critical drilling applications. The major disadvantage associated with CDP that has (until now) prevented its application in UDD and ERD relates to hydraulic performance and efficiency. To achieve the necessary structural properties (torsional strength, tensile capacity, and pressure integrity), a composite tube must be made significantly thicker than the conventional steel drillpipe it is intended to replace. Depending on the design parameters, the wall thickness of composite drillpipe may be up to twice the wall thickness of comparable conventional-steel drillpipe. This results in a significantly reduced ID through the pipe, resulting in unacceptable pressure losses through the pipe. The high strength-to-weight ratio performance of CDP gives it a major advantage compared to steel when evaluating torque and drag-related issues. However, since hydraulic efficiency is just as important, if not more important, for UDD composites do not offer a viable solution in most cases. CDP designers have increased the outer diameter (OD) of the pipe to accommodate the increased wall thickness. For example, 5⅞-in.-OD steel drillpipe is commonly used for UDD. CDP with a 6-in. OD has been proposed for these applications to accommodate the greater wall thickness required for the composite design. Even with this adjustment, the ID is reduced increasing pressure losses, and the increased OD increases equivalent circulating densities (ECDs) in the annulus. This can create well-control issues, especially in wells with a narrow margin between mud-weight and formation-fracture gradients.

CDP has had some success in ultrashort-radius drilling in which its flexibility and fatigue resistance has proved advantageous. Ultrashort-radius drilling is not generally constrained by hydraulic-performance-related issues.

A couple of additional issues must be confronted when dealing with CDP: The tool-joint tube interface can represent a weak link, especially under cyclical loading, and the wear resistance of the composite tube is very limited without additional protective measures. Both of the issues can be addressed through proper design engineering and testing. Experienced engineers have developed interfaces that overcome limitations at this critical connection between the carbon-fiber tube and steel-tool joint. Successful field trials and applications in ultrashort-radius drilling have demonstrated the suitability of this interface. Additional design, analysis, and testing may be required to transfer the interface system from the small diameter pipe (generally 2⅜ to 3½ in.) used for ultrashort-radius drilling to the large sizes commonly required in UDD (5½ to 6⅝ in.).

Protective coatings and centralizers can address the OD wear issue effectively; however, this does add complexity to the manufacturing and maintenance process and cost to the overall product.

Titanium Drillpipe. Titanium drillpipe (Ti DP) has been successfully manufactured on a very limited scale for ultrashort-radius drilling applications. This small-diameter Ti DP (2½ and 2⅞-in.) was proven to be useful for ultra-short radius drilling in several field trial and commercial applications. Unfortunately, the cost to manufacture the product was very high; approximately 7 to 10 times more expensive than conventional, steel drillpipe, and the market was very limited. Consequently, continued production could not be justified from a financial standpoint. The Ti DP was manufactured in a manner that could be adapted to larger-diameter pipe necessary for UDD with additional engineering design, analysis, and physical testing.

The Ti DP assembly consisted of Ti-alloy tubes with internal/external upsets on both ends, high-performance fatigue-resistant proprietary low-alloy carbon-steel-tool joints, and an optimized connection interface between the steel tool-joint and upset Ti tube. Extensive engineering design and testing went into the development of the crucial-connection interface. The final solution incorporates a threaded, shrink-fit interference connection. During final assembly of this connection, the steel-tool joint is heated and bucked on to the tube. When the tool joint cools and shrinks, interference and a robust interface between the two members is generated. This interface was thoroughly tested for fatigue, tensile strength, torsional capacity, and pressure integrity (Smith et al. 2000).

Ti DP offers significant performance advantages when compared to conventional steel drillpipe for UDD applications

- Lower weight. Titanium has a density that is slightly more than half (56%) that of steel.
- A standard Ti alloy that would be suitable for drillpipe has minimum yield strength of 120,000 psi, resulting in strength-to-weight ratio improvement (including steel-tool joints) of approximately 37% over S-135 steel drillpipe.
- Ti is highly resistant to corrosion and erosion.
- Ti has good fatigue resistance and does not suffer from a reduction in fatigue life because of corrosive environments (corrosion fatigue); however, it can be notch-sensitive in fatigue-inducing situations.

Ti is more flexible than steel, with a modulus of elasticity of 17 million psi vs. 30 million psi for steel. While this property was highly advantageous in ultrashort-radius drilling, it may hamper UDD operations. A Ti DP drillstring will have roughly twice the deformation for the same induced stress. This causes a Ti drillstring to behave differently from conventional steel drillpipe in ways that may not be desirable. A Ti drillstring might have a delayed response to changes in working torque, revolutions per minute, and picking up off bottom. It will take longer for changes made at the surface to work their way down through the drillstring when compared to steel. This difference in response can likely be accommodated in drilling operations, but there could be a significant learning curve.

The notch-sensitivity issue mentioned above should likely be possible to address in most cases through implementation of an effective inspection and maintenance program. In highly abrasive applications, centralizers of some kind might be needed to protect the Ti DP tubes from deep scratches and scars.

There is little question that Ti could be used to make a high-performance drillstring that provides an innovative technical solution for pushing the UDD envelope. There are questions that must be answered before Ti DP will be seriously adopted for UD, ER, and other highly challenging drilling projects. Is anyone willing to pay the high cost for the technology that can be an order of magnitude above the cost of steel drillpipe?

Note also, that if only a handful of projects can justify the high cost of Ti DP, it may be difficult for manufacturers to recoup their investment in development, testing, and manufacturing equipment and infrastructure for the relatively small volume of footage required to satisfy this limited number of projects.

How much better (if any) will Ti DP perform when compared to advanced ultrahigh-strength steel with minimum specified yield strengths in the range of 165,000 psi? Compared to 165-ksi-yield-strength steel drillpipe, the strength-to-weight ratio advantage for Ti DP (at 120 ksi yield strength) drops to 15%.

Aluminum Drillpipe. Aluminum drillpipe (Al DP) has been used by the petroleum industry for decades. Most of this experience comes from activity in Russia and the FSU where Al DP is commonly and extensively used. Based on this extensive field history, Al DP is a proven product. Al DP was used in North and South America on a limited basis in the 1960s and 1970s to extend the depth capacity of existing rigs and to reduce weight for transportation of helicopter rigs. Some have referred to Al DP as the "poor man's" Ti DP because it shares some of the desirable features of Ti DP at a cost that is significantly lower. Advantages of Al DP include

- Lower weight
- Good corrosion resistance (although it can be susceptible to corrosion in some mud systems)
- Enhanced fatigue resistance
- Nonmagnetic

Al DP generally costs about twice that of conventional steel drillpipe although this is highly dependent on the specifications for each product. Some sources have indicated that this cost differential may have decreased somewhat recently.

Al DP is made from forged Al tubes that have upset ends. Threaded steel-tool joints are bucked on to the Al tubes with either a shrink-fit connection or with some type of adhesive in the threaded region to secure the two members to one another.

Al DP may have application for drilling in some applications such as ER and horizontal drilling, but it possesses some characteristics that make it a poor candidate for UDD. It has relatively low yield strength of approximately 69,000 psi (highest-yield-strength alloy used for drillpipe). Consequently, it has a lower strength-to-weight ratio than ultrahigh-strength steel drillpipe when factoring in the steel-tool joints attached to the Al tubes. It generally requires a greater wall thickness than steel drillpipe, adversely affecting hydraulic performance. In addition, its yield strength in service can drop off dramatically at temperatures above 250°F. Since high temperatures are often encountered in UDD applications, this characteristic makes it unsuitable for many UD wells.

High-Strength Steels. High-strength steels represent a near, mid- and long-term technology for UDD. Current high-strength grades available on the market today are Z-140 and V-150. These grades provide 4 and 11% improvement in strength-to-weight ratio, respectively, compared to S-135 drillpipe. Cost multipliers for these grade types are negligible compared to S-135 pipe. The industry has been somewhat slow to adopt these grades, but the recent push toward deeper wells has gained momentum. More than7500,000 ft of Z-140 grade and more than 250,000 ft of V-150 is in use today. Predominantly, these grades are being used for drillstrings, but an increasing trend is to use these grades in dedicated drillpipe-landing strings of reduced cyclical loading.

One issue that has inhibited the adoption of high-strength steels has been a concern regarding reduced ductility/toughness of the steel. However, manufacturers have significantly improved the technology and can now offer these grades with longitudinal charpy V-notch (LCVN) toughness levels better than S-135 drillpipe processed to standard American Petroleum Institute (API) specifications. In addition, manufacturers are implementing chemistry, heat treatment and manufacturing improvements that may enable these grades to be manufactured to more stringent toughness criterion in the near-term future.

In 2003, the current state-of-the-art technology in high strength steels was published (Chandler et al. 2003). Analyzing statistical measurements such as cumulative density functions (CDF) on yield strength and toughness values, it was found that there was an approximate 18% probability that Z-140 LCVN values would fall below 59 ft-lbf (¾ size at –4°F). There was a 100% probability that V-150 LCVN values would fall below these same 59 ft-lbs. Examining the data available in 2006 (including the data before 2003), there is a 9% chance that Z-140, and a 50% chance that V-150, will have LCVN values fall below 59 ft-lbf. This indicates that the probability of achieving high ductility/toughness in these high-strength steels has improved by 50% in the past 3 years through manufacturing improvements. **Fig. 4** presents CDF plots from 2003 to present to illustrate these improvements.

The substantial improvement in obtaining high toughness within high-strength steels has led drillpipe manufacturers toward development of ultrahigh strength steels such as UD-165. The development of a UD-165 grade with 165-ksi-yield-strength tubes would provide a product with 22% improvement in strength-to-weight ratio compared to S-135 drillpipe. This would represent a product second only to Ti DP by 15% in strength-to-weight ratio criterion. It is likely that the cost of UD-165 would be substantially less than Ti DP.

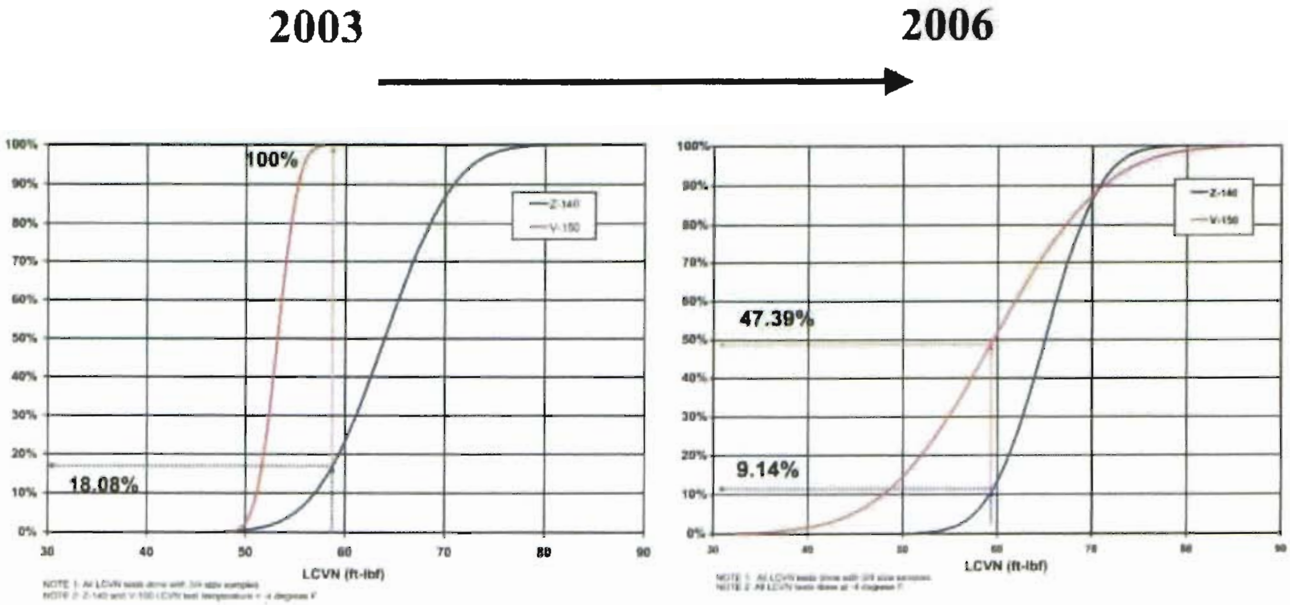

Fig. 4—CDF plots of Z-140 and V-150 LCVN data show 50% improvement in toughness within high-strength steels through manufacturing advancements implemented over the past 3 years.

Fig. 5 provides a summary of advanced-material comparisons alongside S-135, Z-140, V-150, and UD-165 steel-drillpipe products. When considering strength-to-weight ratio, many publications have neglected to factor in the steel-tool joints attached to the nonsteel alternative material tubes. Rather, they have focused on the strength to weight ratio improvement of the material density of the pipe body material only. This is somewhat misleading and errs on the side of promoting nonsteel alternative materials. Fig. 5, however, factors the presence of steel-tool joints and uses a conservative approach by analyzing Range Three drillpipe products.

Advanced-Performance Rotary-Shoulder Connections

A new high-performance rotary-shoulder connection has recently become available for UDD and other challenging applications. It is a third-generation double-shoulder connection for drillpipe and drillstem components that incorporates several innovative features:

- It is the first rotary-shoulder connection to incorporate a double-start or dual-lead thread. This decreases make-up and break-out speed by 50% and consequently greatly improves running and tripping speeds. With the current high operational costs for rigs suitable for UDD, this design characteristic provides the potential for improvements in drilling efficiency and cost-effectiveness. The double-thread configuration also increases connection-torsional strength compared to a similarly configurated single-thread connection.
- This third-generation connection is machined on ultrahigh-strength tool joint forgings with specified minimum yield strength (SMYS) of 130,000 psi compared to standard tool-joint steels with a SMYS of 120,000 psi, further enhancing torsional strength.

Drillpipe Type	Grade	Yield Strength (psi)	Tube OD (in.)	Tube ID (in.)	Tube C.S.A. (in^2)	Tube Tensile Strength (lbf)	Joint Length (ft)	Joint Air Weight (lbf) [3]	Joint Strength to Joint Weight (lbf/lbf)	% Improvement to S-135	Cost Compared to S-135
Titanium	Ti 6Al-4V	120,000	5.875	5.153	6.254	750,421	46.24	741	**1,013**	**37%**	**≈ 7 - 10X**
Steel	UD-165™	165,000	5.875	5.153	6.254	1,031,829	46.24	1,145	**901**	**22%**	**NA**
Aluminum [1]	Al-Zn-Mg II [2]	69,618	5.787	4.764	8.477	590,175	46.24	717	**823**	**12%**	**≈ 1.5 - 2.5X**
Steel	V-150	150,000	5.875	5.153	6.254	938,026	46.24	1,145	**819**	**11%**	**NA**
Steel	Z-140	140,000	5.875	5.153	6.254	875,491	46.24	1,145	**765**	**4%**	**NA**
Steel	S-135	135,000	5.875	5.153	6.254	844,224	46.24	1,145	737	0%	1X
Aluminum [1]	Al-Zn-Mg IV [2]	50,763	5.787	4.764	8.477	430,335	46.24	717	**600**	**-19%**	**≈ 1.5 - 2.5X**
Aluminum [1]	Al-Cu-Mg-Si-Fe III [2]	49,312	5.787	4.764	8.477	418,034	46.24	717	**583**	**-21%**	**≈ 1.5 - 2.5X**
Aluminum [1]	Al-Zn-Mg I [2]	47,137	5.787	4.764	8.477	399,596	46.24	717	**557**	**-24%**	**≈ 1.5 - 2.5X**

Notes:

1 = Aluminum drill pipe design (drill pipe with protector thickening) from ISO 15546 Petroleum and natural gas industries — Aluminum alloy drill pipe

2 = Aluminum drill pipe grades from ISO 15546 Petroleum and natural gas industries — Aluminum alloy drill pipe

3 = includes weight of steel tool joints

Fig. 5—Strength-to-weight ratio comparisons of many steel grades to nonsteel alternative materials including steel-tool joints attached.

- The higher torsional strength inherent in the design of the new connection promotes more-streamlined configurations with larger-ID bores through the connection for better hydraulic performance that is critical for UDD and other critical applications such as ERD and deepwater drilling.

This new double-start threaded connection is discussed in detail in Chandler et al. (2003). Chandler et al. (2003) presents the results of a 2½-year comprehensive effort to design, test, build, and field test a family of connections optimized for each drillpipe size.

Operational Challenges Associated With UDD

There are several operational challenges that become increasingly important when considering UD wells. Because UD wells increase the tensile load of the drillstring, many issues require increased oversight compared to drilling operations with shallower well depths.

Slip Crushing. With increasing tensile load, the slips exert biaxial loads to the drillpipe that convert to hoop stress in the pipe body. Excessive hoop stress can lead to collapse of the pipe body. Damage to slip and slip dies can also result. Slip crushing of drillpipe presents a very real and immediate issue to UDD. In the deepwater GOM, slip-crushing failures have been documented, and some have resulted in catastrophic events involving dropped casing strings (Woltman et al. 2005).

Recent publications have examined the mechanics of slip crushing and suggest that the commonly used Spiri-Reinhold formula may not provide a conservative estimate of drillpipe slip-crushing capacity if initial yielding is the limiting condition (1959). Full-scale physical testing has revealed initial yielding of the pipe body material at values that are approximately 20% less than that predicted by the Spiri-Reinhold formula (Sathuvalli et al. 2002; Paslay et al. 2006).

With greater well and water depths, slip crushing will continue to be an issue of concern, especially when landing long and heavy casing strings, tiebacks, and liners. One method of landing casing strings with weights greater than 1 million lbf has been the use of slipless technologies such as "double elevator" landing-string systems. However, an increasing trend is the coupled use of new and novel slip designs with special Slip-Proof® drillpipe landing strings. **Fig. 6** provides a schematic of a state-of-the-art drillpipe landing-string design (Chandler et al. 2003). To improve slip-crushing capacity, a machined OD and ID tube that has minimal eccentricity and ovality is welded between the box-tool joint and drillpipe-tube upset. This tube section has a much greater wall thickness than the drillpipe body that, in combination with the material strength, provides greater slip-crushing capacity than the tensile capacity of the drillpipe body to which it is attached. The length of this slip section can be extended up to 73 in. to enable efficient tonging operations, as well as setting and disengagement of either manual or power slips without the risk of engaging them on the pipe body. This is critical if the pipe body is made of higher strength materials, such as Z-140 and V-150.

Segregation of the slip-tube section from the drillpipe body provides increased slip-crushing capacity to more closely match the pipe body tensile capacity. Because the entire tube length does not require a thick-walled slip section for slip crushing resistance on casing landing strings, high strength, and thinner wall-pipe bodies can be used, greatly reducing weight of the drillpipe landing string. In some cases, savings can be as much as a 28% reduction in joint weight (Chandler et al. 2003).

Slip-Proof® drillpipe is becoming increasingly used in the deepwater market. Several strings have been and are currently being manufactured. For the industry's continued push toward UDD, some of these strings provide a full 2-million-lbf rating in slip-crushing, hoisting, and tensile capacity.

Slip manufacturers have also developed technologies to improve slip-crushing capacity and minimize damage to slip segments and inserts. Recently, some of the industry's first slip assemblies that are rated for 2 million lbf have been introduced to the market. This slip system is presented in **Fig. 7.** There are essentially three features in this slip system that improves slip-crushing performance:

- Slip dies are inserted in load distribution grooves. This improves load distribution throughout the slip and minimizes loading on the toe area compared to former slip systems.
- The contact area of the slip has been extended from 16 to 20 in., dispersing the load over a greater area, reducing the contact stress in the slips as well as in the drillpipe body.
- Another feature to reduce slip loading is the modified taper between the slip and bowl. Rather than the conventional taper between the slips and drilling bowl of 4:1, this slip system provides an increased taper that reduces the transverse loading to the drill-

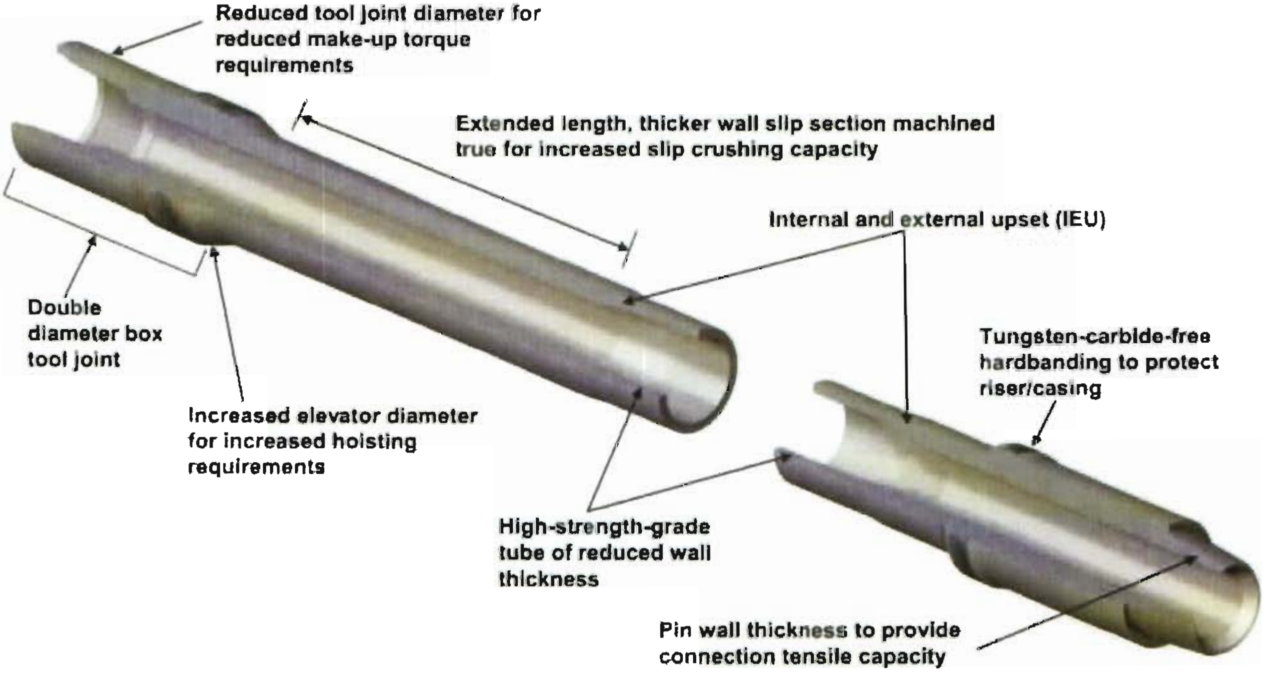

Fig. 6—State-of-the-art drillpipe landing string design for UDD wells with thicker wall slip section to improve slip-crushing resistance (Chandler et al. 2003).

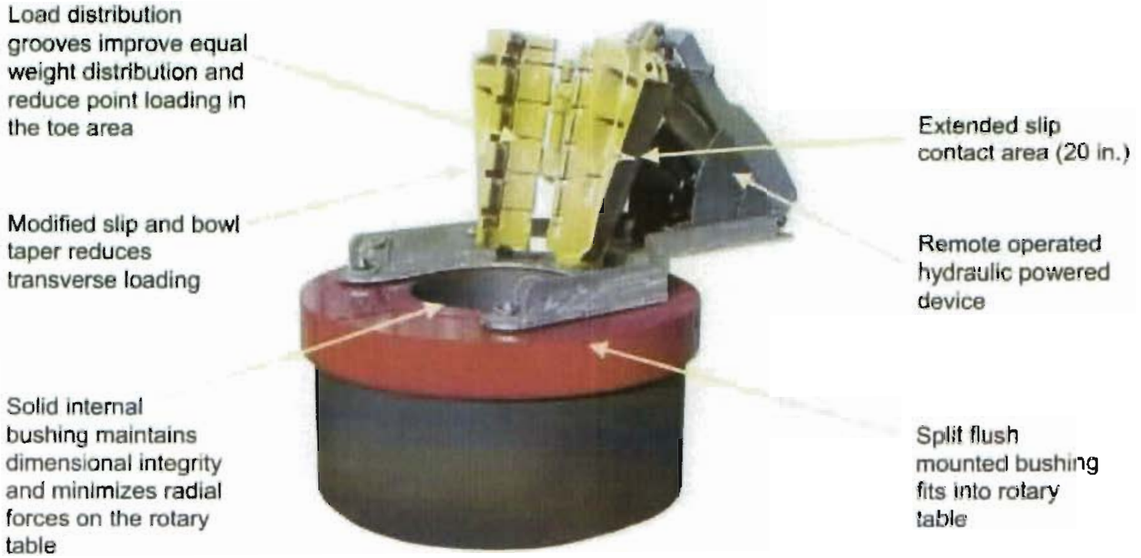

Fig. 7—Three key features of 2-million-lbf slip system is load-distribution grooves, extended-slip-contact length, and the increase of the taper between the slips and bowl to reduce transverse loading to the pipe.

pipe, resulting in an increase in the tensile load before slip crushing is initiated.

It is clear that both drillpipe and handling equipment manufacturers have developed and are developing technologies to improve the industry's resistance to slip crushing and to extend UDD capability.

Hoisting Capacity. Hoisting capacity of the drillstring is also an area of increased importance when undertaking UD wells. Confirming that the top drive load rating exceeds anticipated drillstring weight plus a safety factor is one aspect. Another aspect is ensuring that elevator load ratings also exceed the weight of the drillstring plus a safety factor. However, one area that is becoming of increasing concern and is not readily verified is tool-joint elevator capacity.

The increasing trend in UDD and deep-directional wells is to use proprietary high-torque tool-joint connections on the drillpipe. One aspect of these connections is reduced OD for ECD management and fishability in smaller wellbore diameters. More streamlined product configurations are being offered in which the tool joint OD more closely approximates the tube OD. For example, a popular size in UDD is 5⅞-in. 26.30 lbf/ft S-135 drillpipe with 7 in.×4¼-in. connections attached. The maximum upset diameter for this pipe is 6 in., and the typical elevator bore diameter is 6⅛ in. This leaves approximately ⅞ in. of axial contact along the 18° taper of the box-tool joint and the elevator bushing. In most cases, the SMYS of the tool joint is 120,000 psi and the elevator bushing is 110,100 psi. Contact stress between the 18° tool-joint taper and elevator bushing under axial load must be less than 110,100 psi to avoid plastic deformation of the bushing and potential slippage of the drillstring through the elevator.

Tool-joint elevator capacity is a direct function of the tool-joint OD. Drillstring design engineers should consult the original equipment manufacturer (OEM) of the elevators intended to be used to obtain elevator capacity charts on the basis of tool-joint OD to ensure that anticipated hoisting loads are within the load rating of the elevators based on joint-elevator contact area (see **Fig. 8**).

Drillpipe manufacturers have developed tool-joint designs that aid in providing elevator capacity while maintaining balanced connections and fishability considerations. Double-diameter tool joints were introduced to the industry in early 2002. At the end of the tool joint near the 18° taper, a larger diameter is featured to provide greater contact area with the elevator. This diameter is selected to ensure that full elevator load ratings are preserved. This larger diameter extends from the 18° taper down the tool joint length approximately 3½-in., where a transition radius is provided to the smaller tool-joint diameter for the remaining tong space. The area occupied by the larger diameter also provides sufficient area to apply hardbanding to the box tool joint for increased wear protection. The smaller tool joint diameter is specified to ensure a balance of the area/stiffness ratio between the pin and box to maximize fatigue performance of the tool joint. In addition, dimensions required to allow fishing over the box-tool joint are taken into consideration in determining the area where the smaller tool-joint diameter exists. Most overshot fishing tools are capable of catching the smaller tool-joint diameter without interfering with the larger diameter near the 18° taper as long as sufficient tong space exists. Drillpipe owners should consider these requirements when ordering new drillpipe that is to be used in UDD operations to ensure that the above features can be employed without impact to fishability. This double-diameter tool-joint design makes tool-joint elevator capacity independent of the tool-joint OD defined for fatigue and fishability concerns. In some cases, as much as a ½-in. variance between ODs has been manufactured.

Similar to drillpipe manufacturers, elevator manufacturers are also making strides to improve hoisting capacity for UDD. A challenge to elevator manufacturers has always been the spreading force applied to the elevator under heavy axial load. This spreading force is the primary factor in establishing elevator-load rating. Some of the highest rated elevators on the market for use with drillpipe that features standard 18° elevator tapers on the box-tool joint have been 750 tons. Some elevator manufacturers have successfully increased load ratings by changing the taper angle from 18 to 35° to reduce the spreading force on the elevators used. However, recently equipment manufacturers have begun or to introduce 2-million-lbf-rated elevators for use with 18° drillpipe. Some of these elevators feature hydraulic actuation and have insert bushings that can be replaced when worn.

Both drillpipe and handling-equipment manufacturers have successfully developed technologies to address the heavy hoisting loads associated with UDD.

BOP Pipe Shearing. The use of higher-strength, higher-toughness drillpipe of increased wall thickness required to absorb high tensile loading has in some cases exceeded the capacity of some BOP shear rams to successfully and/or reliably shear drillpipe. Several variables impact a BOP's ability to shear drillpipe, including:

- Drillpipe outside diameter
- Drillpipe wall thickness
- Drillpipe material strength (ultimate and yield)

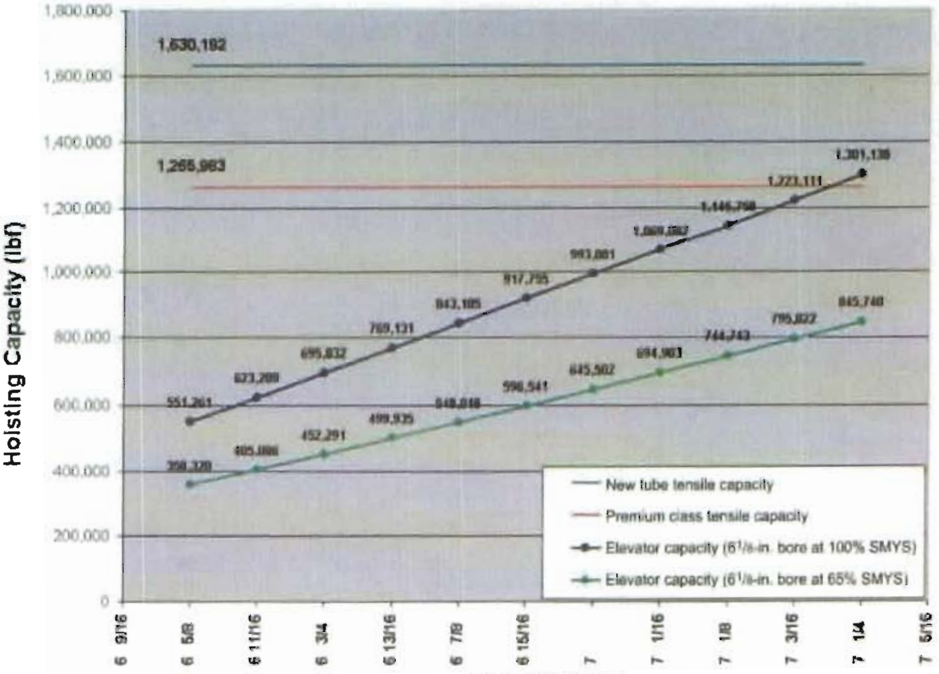

Fig. 8—Hoisting capacity is a function of tool-joint OD. In addition to the elevator load rating, drillstring design engineers should consult the OEM for tool-joint elevator-capacity curves.

- Drillpipe material toughness/ductility
- Wellbore pressure (mud-hydrostatic head and trapped wellbore pressure equal to maximum BOP working pressure)

To reduce the probability of drillstring failure, the industry has increased its appetite for high-toughness drillpipe. Increased material toughness/ductility provides resistance to crack propagation and often enables the material to sustain a through-wall crack without catastrophic failure, commonly known as "leak before break." In response to this desire, drillpipe manufacturing companies have implemented chemistry, heat treatment, and manufacturing advances that produce extremely ductile pipe, even in high-yield-strength products such as Z-140 and V-150 products. Traditionally, there has been no upper limit for the level of toughness desired, and manufacturing companies have tried to achieve as much ductility in their pipe as possible.

Over the past few years, it has become clear that this successful improvement to drillpipe properties has not been achieved without consequence. Several publications have presented the effects of improved-drillpipe properties on BOP shearing capabilities. This has initiated multiple industry studies, including those performed by regulatory bodies. A consistent finding throughout all of these studies is that drillpipe material ductility and toughness is one of the major influences to the amount of force/pressure required for shear rams to successfully and reliably shear drillpipe.

In many cases, shear-ram operating pressures exceeding 3,000 psi have been required to successfully shear S-135 and higher-strength drillpipe that possess high ductility and toughness properties. This presents a significant well-control issue for the many rigs currently equipped with BOP stacks that have 3,000-psi operating systems. From studies performed for the US Minerals Management Service (MMS), **Fig. 9** presents two 5½-in. 24.70-lbf/ft S-135 pipe samples. The sample on the left is less ductile and has lower toughness than the sample on the right. Shear testing indicated that the highly ductile/tough sample required a shear-ram

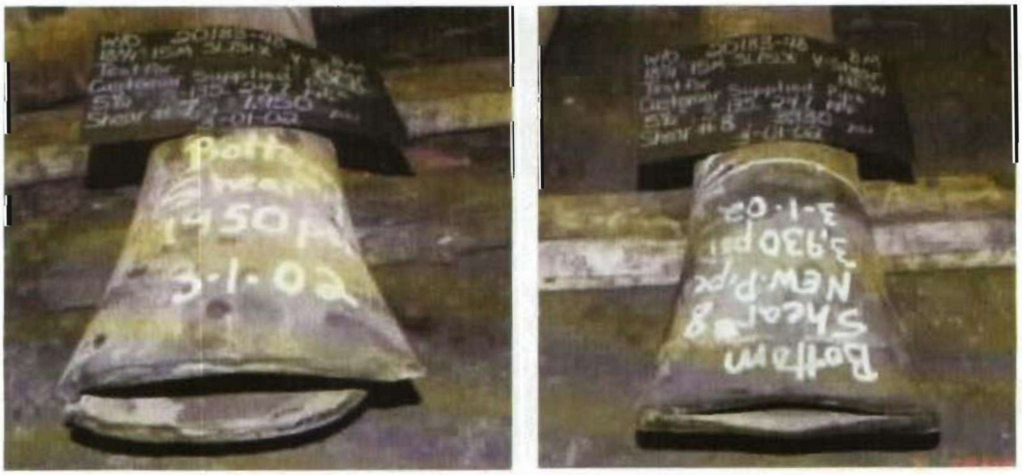

Fig. 9—Nearly 2,000 psi of increased pressure was required to shear the more ductile sample on the right. Both drillpipe samples were equivalent OD, wall thickness, and grade (West Engineering).

operating pressure of 3,930 psi to shear it, while the less ductile/tough sample required 1,950 psi of shear-ram operating pressure. This represents a difference of nearly 2,000 psi of increased operating pressure to shear the highly ductile/tough pipe of equivalent OD, wall thickness, and grade (West).

In response to this issue, BOP manufacturers have taken a number of steps. One step in particular has been the execution of numerous shear tests on pipe of varying OD, wall thickness, grade, and toughness. Levett (2003) has shown that shearing pressure requirements are more directly tied to toughness/ductility than to the strength of the pipe, though strength is also an influencer. **Fig. 10** presents graphs from this paper. It can be seen that as LCVN (a measure of toughness/ductility) increases beyond 40 ft-lbf (¾-size specimen at −4°F), shearing-pressure requirements dramatically increase.

On the basis of this testing, BOP manufacturers have also revisited prediction formulas for shearing requirements and have empirically derived a set of new formulas that are now based on the material ultimate tensile strength (rather than yield strength) and material toughness [three different equations for different toughness ranges (Levett 2003)]:

$$F_{shear} = 0.577 \times (UTS) \times A_{DP} \ldots\ldots\ldots\ldots \text{LCVN} \geq 50 \text{ ft-lbs}$$

$$F_{shear} = 0.577 \times (UTS) \times A_{DP} \times 0.8$$
$$\ldots\ldots\ldots\ldots 40 \text{ ft-lbs} \leq \text{LCVN} < 50 \text{ ft-lbs}$$

$$F_{shear} = 0.577 \times (UTS) \times A_{DP} \times 0.6 \ldots\ldots\ldots \text{CVN} < 40 \text{ ft-lbs}$$

where:

F_{shear} = force required to shear pipe, lbf

UTS = pipe ultimate tensile strength, psi

A_{DP} = cross-sectional area of pipe, in^2

LCVN = ¾-size specimens tested at −4°F

UD wells beyond 25,000 ft TVD often require large-OD tubulars such as 6⅝ in. with tapered wall thicknesses ranging from 0.361 in. to as much as 0.938 in. These tubulars are often manufactured to stringent and elevated toughness requirements greater than 59 ft-lbf (¾-size samples at −4°F). They are often high-strength S-135, Z-140, and V-150 products. In some cases, as many as four different wall thicknesses of 6⅝-in. drillpipe are used in the same string. Each of these trends in UDD drillstrings—increasing wall thickness, increasing yield, ultimate tensile strength, and increasing material ductility—all adversely impact the ability of the BOP to successfully and reliably shear the drillpipe.

BOP manufacturers have designed larger shear-ram-operating cylinders that are capable of exerting greater shearing force at the same pressure. In addition, the operating pressures of some ram-operating systems have been increased to pressures above 3,000 psi to deal with this issue. The design limit with these improvements is the compressive force capacity of the ram-shaft assemblies.

It is important during the UD well planning process that engineers fully evaluate the ability of the BOP to successfully shear the drillpipe. Project-specific full-scale shear testing with actual drillpipe to be used on the project may be necessary to fully answer this question.

Hang-Off Capacity in BOP With Externally Applied Pressure. Another operational concern in UDD is a potential loading scenario that may be applied to the drillstring. This scenario can occur during a well-control event or during displacement operations to control a kick. Once a kick is detected, the standard procedure is usually to shut in the well and to take pressure measurements inside the drillpipe and annulus to estimate the intensity and size of the kick. If the well is left shut-in and the kick is allowed to migrate up the annulus to the BOPs, the pressure in the annulus will increase substantially depending on the nature of the kick (gas vs. oil vs. saltwater), size of the kick, intensity of the kick, well geometry, and fluid weights.

Because floats are often run inside the drillstring, an accompanying pressure increase inside the drillstring may not occur, and a significant pressure imbalance between the drillpipe external and internal pressure may develop at or near the BOPs. Well-control pressures in the annulus can form an effective collapse load on the drillpipe that may threaten the pressure integrity of the seal between the BOPs and the drillstring.

During this scenario, the effective pressure limit of the well may be limited by the collapse rating of the drillpipe, despite a 10- or 15-ksi BOP system being in place. This is especially important in UD wells for two reasons: Increased axial load to the drillpipe reduces collapse resistance of the drillpipe, and larger-OD drillpipe commonly run in UD wells has lower collapse resistance than smaller-OD tubulars of equivalent wall thickness.

Drillstring design engineers for UD wells should consider the reduced collapse resistance of the drillpipe at the BOP under the appropriate heavy-tension loads. In addition, the use of ported and nonported drillpipe floats may aid in reducing pressure differentials across the drillpipe. Operations personnel should consider this potential loading scenario and account for it during planning for well control events on UD wells (*ISO/ICD10407-1* 2004).

BHA Connections for UDD. Considering the cost of drillstring failures in UD wells, it is essential that advanced drillstring technology be utilized to minimize risk exposure. Of particular concern in deep wells is the risk of BHA connection failures. Trips at

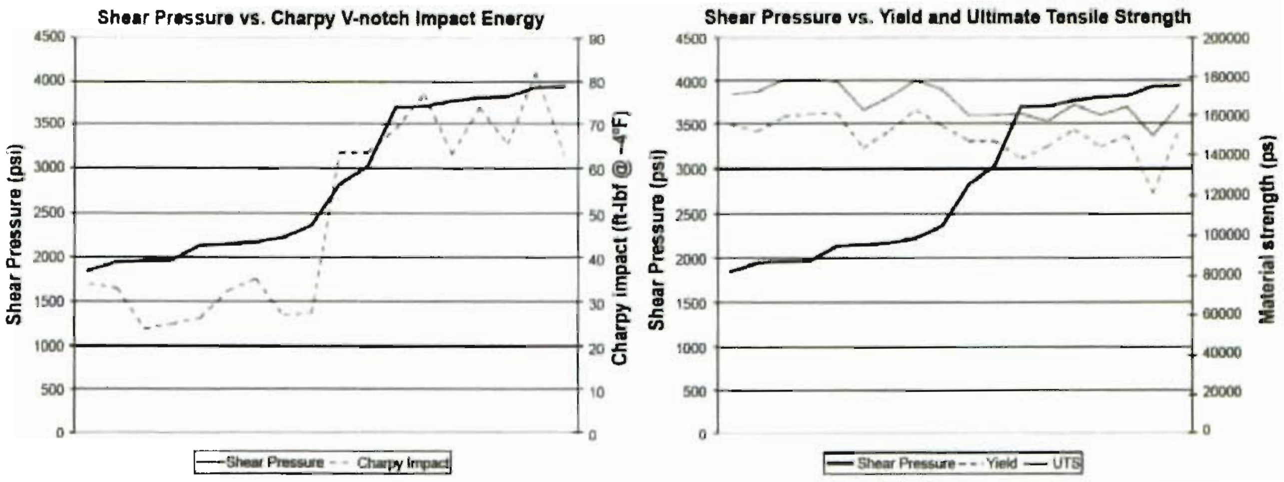

Fig. 10—Full-scale shear testing of drillpipe shows that shearing capacity is more greatly dependent on drillpipe ductility/toughness (left) than yield or ultimate tensile strength (right) (Levett 2003).

UD-well depths are costly, and unsuccessful openhole fishing operations followed by sidetracks are even more costly.

The requirement for double-shoulder connections in the BHA to enable telemetry transmission of wired drillstrings (IntelliServ® network) has developed. In response to this need, drillstring manufacturers have developed proprietary double-shouldered BHA connections aimed at maximizing fatigue performance and permitting telemetry transmission. These enhanced connections have been subject to extensive design verification activities such as finite element analysis, full-scale fatigue, torsion, and make-and-break testing. In addition, field trials have been conducted in aggressive drilling programs with elevated BHA vibration. Results indicate that the enhanced BHA connection provides at least nine times greater fatigue resistance than its API counterpart connection, 6⅝ Regular, of equivalent OD and ID (see **Fig. 11**). In addition, noticeable improvement in running time and material loss upon recut has also been observed (Chandler et al. 2005).

The industry has used single-shoulder API connections in the BHA for several decades, and most BHAs have tools from multiple suppliers, all coordinating with the same standardized connection. To change this paradigm to a proprietary connection throughout the BHA requires a significant step change and commitment between the operator and drilling contractor. Mutual benefits can be gained in this partnership including improved connection performance, improved fatigue life, and risk reduction, which can justify any additional costs and efforts needed to convert the entire BHA to this connection, not only with conventional BHAs needed for use in aggressive drilling programs and UD wells, but also for use in telemetry drillstrings where double-shouldered connections are needed.

Conclusions

1. The trend toward ultradeep wells is increasing. Ultradeep wells deeper than 25,000 ft TVD and with departure/TVD ratios less than 0.25 are increasingly more common. Since 1995, the number of annual US wells deeper than 15,000 ft TVD has more than doubled. Ultradeep well types present strong challenges to drillstring design engineers that may prove more demanding than those overcome in ER programs.
2. Long-term solutions for overcoming the tensile load limits of conventionally designed drillpipe used in ultradeep wells may include nonsteel alternative drillpipe products. These products will require investment in design verification, full-scale physical testing, and field trials to understand the risks and different mechanics. Near- and mid-term solutions should be focused on the use of current and further development of high-strength, high-toughness steel drillpipe. These products provide adequate strength-to-weight ratios at a fraction of the cost of nonsteel alternative materials.

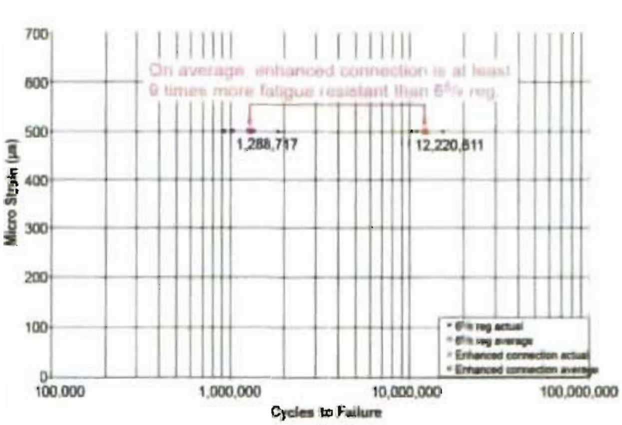

Fig. 11—Full-scale fatigue testing (right) indicates that enhanced BHA connection (left) provides at least nine times more fatigue resistance than API 6⅝-in. Regular connection. This enhanced connection will provide risk reduction to costly BHA failures in UD wells (Chandler 2005).

3. A new third-generation double-shoulder connection for drillpipe that provides increased torsional strength, faster running speeds, and better hydraulic performance is available for critical UDD and other challenging applications.
4. Increased drillstring tensile loads associated with ultradeep wells require improved design assessment in areas such as slip crushing and hoisting capacity. New drillpipe and handling-equipment technologies provide novel solutions that enable current UDD requirements.
5. UDD presents increased operational considerations that require attention of the well designer. BOP shearing capacity of drillpipe and BOP pressure integrity upon drillpipe collapse are adversely affected in UD wells. Well designers should work closely with OEMs to fully evaluate the performance limits of these products in ultradeep applications.
6. The risk and cost of ultradeep wells will strongly benefit from advanced BHA connection technology aimed at mitigating downhole failures. Enhanced BHA connections are available with fatigue performance improved a full order of magnitude over current API connections. This step-change performance improvement justifies the logistics of sourcing enhanced connections throughout the BHA, including tools from multiple suppliers.

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SI Metric Conversion Factors

ft × 3.048*	E−01	=	m
ft-lbf × 1.355 818	E+00	=	N-m
(°F−32) × 0.555 556	E+00	=	°C
in. × 2.54*	E+00	=	cm
ksi × 6.894 757	E+03	=	kPa
lbf × 4.448 222	E+00	=	N
lbm/in^3 × 2.767 991	E−02	=	kg/cm^3
psi × 6.894 757	E+00	=	kPa

* Conversion factor is exact.

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