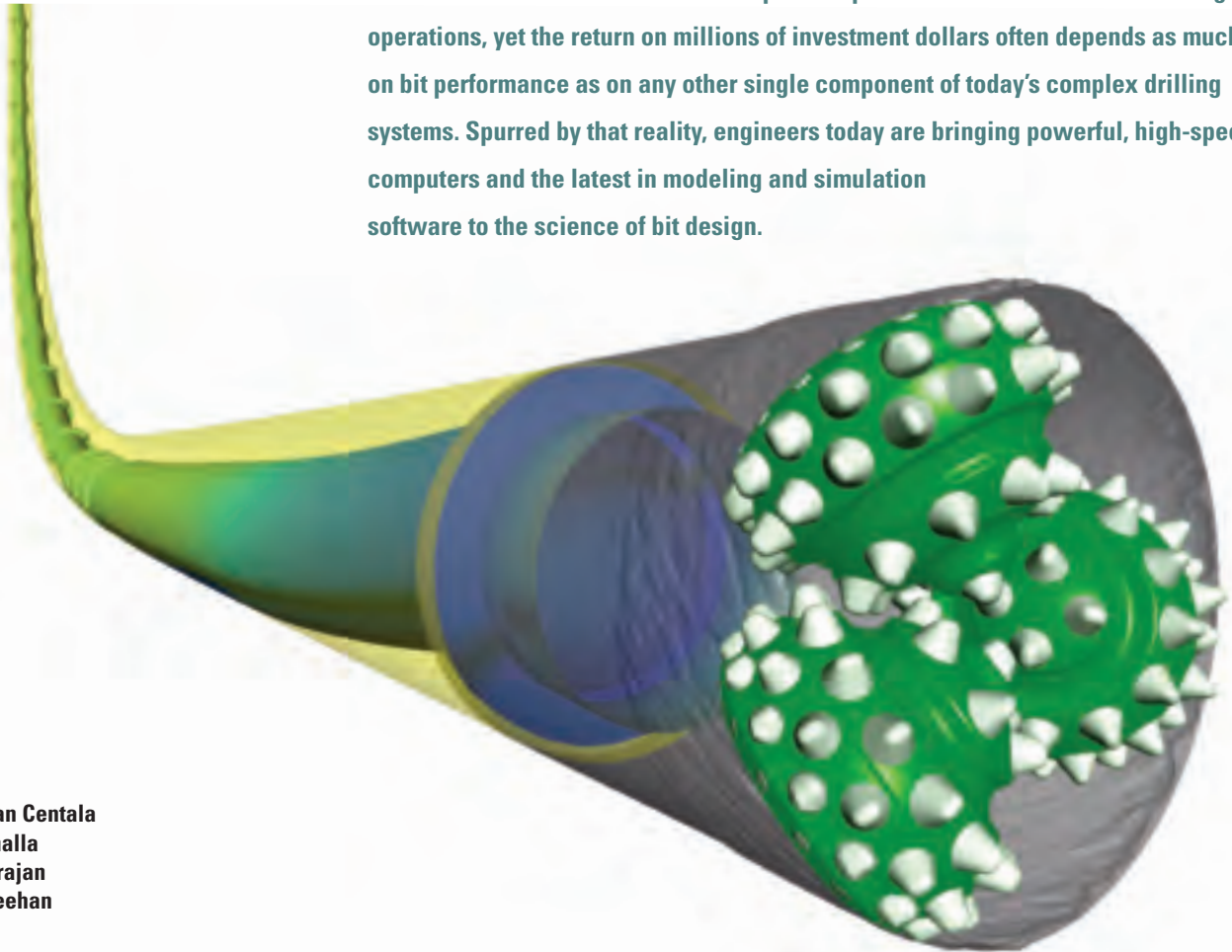


Bit Design—Top to Bottom

Individual bits are one of the least expensive pieces of hardware used in drilling operations, yet the return on millions of investment dollars often depends as much on bit performance as on any other single component of today's complex drilling systems. Spurred by that reality, engineers today are bringing powerful, high-speed computers and the latest in modeling and simulation software to the science of bit design.



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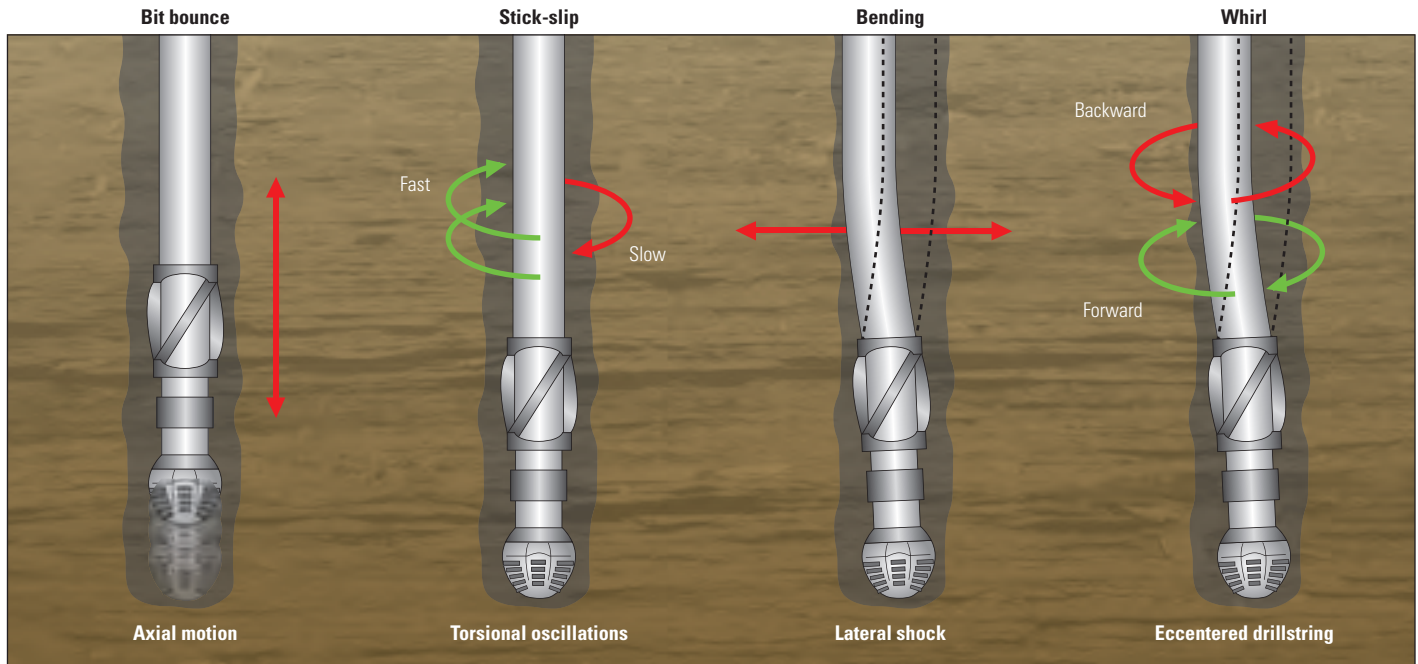
For help in preparation of this article, thanks to Guy Arrington, Ashley Crenshaw, Diane Jordan and Chuck Muren, Houston; and Emma Jane Bloor, Sugar Land, Texas. DBOS, IDEAS, i-DRILL, ONYX and Spear are marks of Schlumberger.

Bit choice has long been viewed as a key to successful drilling operations. The right bit plays a leading role in optimizing rate of penetration (ROP), which helps minimize rig costs and shortens the time between project commissioning and first production. In field development programs, predictable ROP is critical to efficient allocation of rigs, personnel and materiel. Operators are drilling increasingly complex, extended-reach wells in which a bit poorly matched to the formation, drilling parameters, BHA or downhole tools may introduce unwanted dynamics or create forces that cause the well path to stray from the planned trajectory.

On the other hand, a correctly designed bit delivers a more in-gauge hole and a less tortuous

well path. These wellbore characteristics allow engineers to more easily log the hole and then to install the tubulars, tools and instrumentation required for the planned completion.

At one time, engineers designed and selected bits based on little more than rough estimates of formation hardness, interval depth and hydraulics. However, as with many aspects of drilling and production, in recent years, the science of bit design has evolved at an accelerated pace. Options within the general categories of fixed cutter and roller cone bits have grown from a select few to a wide variety differentiated by manufacturing material, processes and function.¹



^ Vibration sources. Axial motion, or bit bounce, has a characteristic frequency whose value is a function primarily of the type of bit, mass of the BHA, drillstring stiffness and formation hardness. Torsional oscillations, or stick-slip, result from an excessive amount of torque in the drillstring. This type of motion also has a frequency dependent on the mass of the BHA, torsional stiffness of the drillstring and dogleg contact points. Stick-slip often results in transients of extreme lateral vibrations. Lateral shock refers to sideways bending of the BHA, and is often chaotically coupled to axial and torsional motions. BHA whirl is the bending and precession of the drillstring center around the borehole. This eccentric movement can be either forward—that is, in the same rotational direction as the pipe—or backward. Forward whirl is very common and is induced by centrifugal forces caused by any slight imbalance in the drill collars. Backward whirl results when the frictional forces between the drill collar and the borehole are sufficient to cause the drillstring to move backward along the borehole wall.

While bits have never been designed in total isolation, today's high-speed computers have made it possible to consider the entire drilling system in far more detail and in a far more holistic manner than ever before. Designers are also able to better match the bit to the formation and thus avoid low ROP or excessive nonproductive time (NPT) caused by trips to replace worn bits.

The most damaging result of poor bit design is the creation of excessive downhole shocks and vibrations. Vibrations can cause anything from slow ROP—induced by premature bit wear—to damage and ultimate failure of complex and costly downhole electronics. Vibrations are caused primarily by often-linked drilling phenomena known as bit bounce, stick-slip, bending and whirl (above).

Bit bounce most frequently occurs when drilling vertically through hard formations, usually with a roller cone bit, but it may also occur with a fixed cutter bit. The cutting action of tricone roller bits tends to create lobes on the bottom of the hole, which causes the bit to be axially displaced three, six or even nine times per bit revolution, changing the effective weight on bit (WOB) and repeatedly lifting the bit off and then

slamming it back to bottom. The resulting axial vibrations damage bit seals, cutting structures, bearings and BHA components and also reduce ROP and destroy downhole sensors.

One operator has said stick-slip accounts for about 50% of on-bottom drilling time.² Stick-slip, a function of the rotary speed of the BHA, occurs when the bit stops turning due to friction between the bit and the formation. Once torque within the drillstring becomes greater than these friction forces, the bit releases from the wellbore wall and is spun by the unwinding of the long drillstring at very high angular velocities, causing destructive lateral movement.

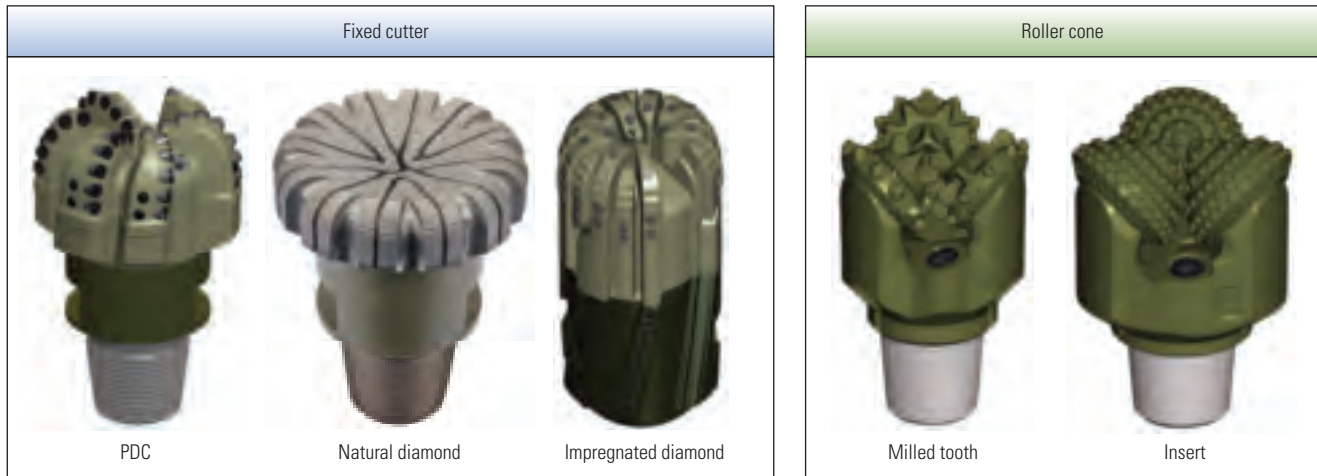
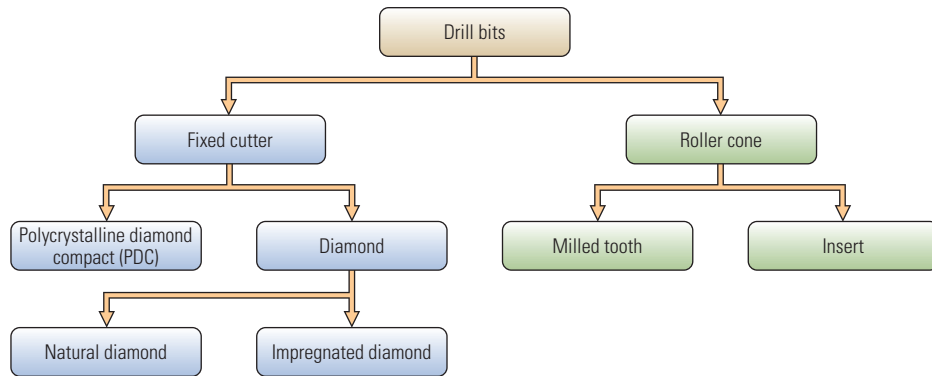
Bending is caused by placing too much downward force on the drillstring. This can create lateral shocks when the drillstring is deformed enough to make contact with the wellbore.

Another operator has estimated that 40% of footage drilled worldwide is adversely affected by bit whirl.³ Whirl creates severe lateral movement at the bit and the BHA. A drilling imbalance brought on by a poorly selected bit or negative bit-BHA interaction pushes one side of the bit against the wellbore wall, creating a frictional force. When drilling a gauge hole, the bit rotates

about its center. But during whirl, the instantaneous center of rotation becomes a cutter on the face or gauge of the bit, the same way a turning axle moves the instantaneous center of rotation of a car's tire to the road. As a consequence, the bit tries to rotate about this contact point.

Because the bit's center of rotation moves as the bit rotates, one result of whirl is an overgauge hole. Motion within this hole may force the cutters to move backward (relative to the surface rotation), or laterally, causing the bit to travel longer distances per revolution than in a gauge hole. These actions create high-impact loads on the bit and BHA. Whirl also creates a centrifugal force that pushes the bit toward the wall, increasing the frictional force, which in turn reinforces whirl.⁴

1. For more on bit types and manufacturing: 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. Xianping S, Paez L, Partin U and Agnihorti M: "Decoupling Stick-Slip and Whirl to Achieve Breakthrough in Drilling Performance," paper IADC/SPE 128767, presented at the IADC/SPE Drilling Conference and Exhibition, New Orleans, February 2–4, 2010.
3. Xianping et al, reference 2.
4. Brett JF, Warren TM and Behr SM: "Bit Whirl—A New Theory of PDC Bit Failure," *SPE Drilling Engineering* 5, no. 4 (December 1990): 275–281.



▲ Drillbit designs. Selection begins with a choice between a bit whose cutting mechanism is fixed to the bit body or on roller cones. A selection of fixed cutters (*left*) may be further refined, based on formation hardness, by opting for PDC or natural diamonds, which are on cutter blades or impregnated into the bit body. Roller cones (*right*) consist of milled-tooth cutting structures or inserts.

Traditionally, the driller must change WOB or pipe rotation speed to counter drilling dysfunctions such as bit bounce, stick-slip, whirl and bending. Increasing WOB may induce stick-slip and raising the rotation speed may invite whirl. Restraining both may reduce all four types of vibrations but result in unacceptably low ROP.

The third choice is to find an optimized combination of the two variables, which may be done only when the bit, BHA, drillstring and hydraulics program are integrated as part of a drilling system rather than as isolated components. Engineers have long known how to model the complete system. However, the volume of calculations to do so has historically required an investment of time that made the task economically untenable. Additionally, the parameters calculated were valid for only a single instance in a specific formation in a well.

These limitations have been overcome in recent years by the proliferation of fast, powerful computers that have allowed designers to model the performance of drilling systems for specific

applications. The result has been an increased ability to minimize axial and lateral vibrations by determining the optimum range of WOB and rpm. Even more important, engineers are able to design systems before they are manufactured.

This article looks at the tools available for modern bit design including simulation, modeling and finite element analysis programs. Case studies from offshore West Africa, Peru and the US will demonstrate the impact increased computer power is having on drilling operations.

Drillstring Design as an Iterative Process

The aim of drillbit design is creation of a bit, which, when matched to the correct BHA, down-hole tool, formation to be drilled and drilling parameters, will perform optimally as defined by the following:

- ROP
- durability
- stability
- steerability
- versatility.

Each of these metrics is weighted by the operator according to the specifics of the section to be drilled. For example, if fast ROP is the primary driver in a given interval, it may require sacrificing bit durability for faster drilling, resulting in faster bit wear. Similarly, if steerability is of primary concern, the operator may be forced to use a less aggressive bit and slow the ROP.

Guided by operator objectives and the characteristics of the formations to be drilled, bit designers consider many options for each facet of the bit. The bit designer must first choose between a roller cone or fixed cutter bit ([above](#)).

On roller cone bits, the cones turn independently as the BHA rotates on bottom. Each cone has cutting structures of hard-faced steel or tungsten-carbide inserts. By design, they wedge and crush like chisels, or gouge and tear like shovels, depending on formation hardness.

By contrast, fixed cutter bits, or drag bits, have integral blades that turn together. Their steel cutting structures may include natural diamonds suspended in the blade matrix. The body of the fixed cutter bit is a cast of tungsten-carbide matrix or machined steel. Composed of man-made polycrystalline diamond compact (PDC), fixed cutters shear the bottom of the hole.⁵

Historically, bits and BHAs were chosen through a process of elimination. For a given drilling program, engineers first chose a bit based on offset well data. The amount and value of the data vary according to location, but of special interest to drillers are bit records that include bit type and design used, ROP, footage drilled per bit and an accurate International Association of Drilling Contractors (IADC) bit grading. Based on this information, a specific bit type is chosen and run. When the driller decides the bit is no longer effective—for example when the ROP slows below a predetermined rate—the drilling is pulled and the bit inspected. This empirical bit selection process continues in many drilling programs today.

The bit is then analyzed for cutting structure wear and breakage. Historically, drillers learned through experience how to examine a used bit, called a dull, to determine what type of bit to run next or what changes to make to the bit type. In the 1950s, the industry established general guidelines for relating typical bit wear patterns to possible causes.⁶ In 1961, responding to a need for a common vocabulary and standard reporting method, the American Association of Oilwell Drilling Contractors (AAODC) established the first dull-bit grading system. It graded teeth and bearing wear on a 1 to 4 scale in which a 4 was a missing or totally flat tooth or a missing or locked bearing. Soon after, the system was expanded to a 0 to 8 scale with added detail.⁷

In March 1985, the IADC, successor to the AAODC, recognized that the system was again in need of updating. Bits had evolved since the last system update, most significantly with the inclusion of journal bearings and tungsten-carbide inserts.⁸ The new system was adopted in March 1986. In addition, a fixed cutter dull grading system, created in 1987, was revised in 1991 and was presented to the industry in 1992 (above right).⁹

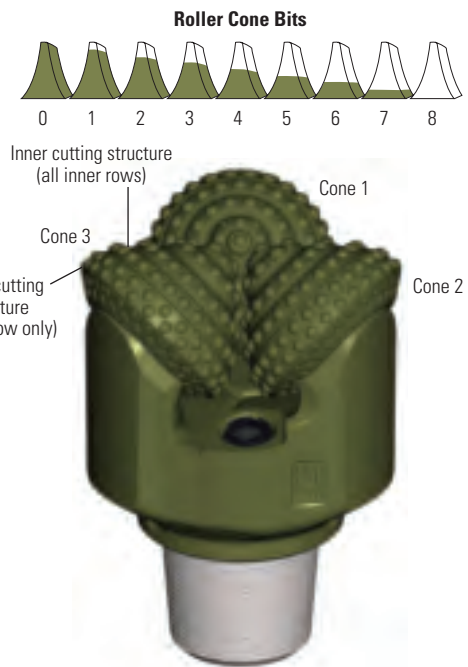
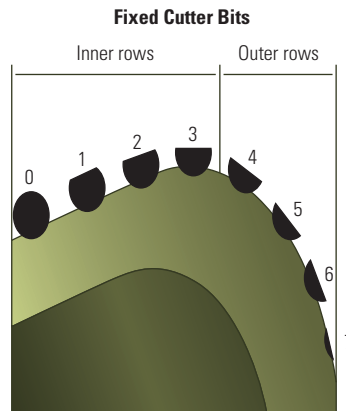
With this standardization of wear analysis and reporting, it became possible to create bit records that could be used to select bits and drilling components for similar wells. Smith Bits, a Schlumberger company, initiated a Drilling Record System (DRS) in 1985. Today this database of nearly three million drillbit runs includes records from every oil and gas field in the world.

However, as exhaustive as these records are, they contain an element of subjectivity, which can impact bit life and performance from one well to the next. Additionally, bit performance may be impacted by significant lithology variation within a field.

In past efforts to improve drilling performance, engineers have used the dull grading chart to make changes to the bit design, the BHA and drilling parameters after each run. As each new configuration was run, engineers analyzed bit performance, graded the bit and made changes

IADC Bit Dull Grading Code

Cutting structure				B	G	Remarks	
Inner rows	Outer rows	Dull characteristic	Location	Bearing seals	Gauge $\frac{1}{16}$ in.	Other characteristic	Reason pulled



^ Grading dulls. Using a linear scale from 0 to 8, engineers assign a value to cutters in the inner and outer rows of bits to indicate amount of wear. Grading numbers increase with amount of wear, with 0 representing no wear. Eight indicates that no usable cutter remains. PDC cutter wear is also measured in a linear scale from 0 to 8 across the diamond table—the diamond section atop the cutting structure—regardless of the cutter shape, size, type or exposure. Today, the dull grading system adopted by IADC includes codes to dull grade both fixed cutter (left) and roller cone (right) bits. The engineer assessing bit damage uses a chart that includes eight drillbit factors. The first four items on this chart (top) describe the cutting structure. The third and seventh spaces are for noting dull characteristics of the bit, which are the most prominent physical changes relative to its condition when manufactured. The fourth space, location, indicates the location of the primary dull characteristics noted in the third space. For fixed cutter bits, one or more of four profile codes is used to indicate the location of the noted dull characteristic. The fifth item, labeled B, refers to bearing seals and does not apply to fixed cutter bits. This space is always marked with an X when fixed cutter bits are graded. The sixth item, G, refers to gauge measurement. The gauge space is used to record the condition of the bit gauge. If the bit is still in gauge, the letter I is placed here. Otherwise, the amount by which the bit is undergauge is recorded to the nearest one-sixteenth inch. The last two spaces, remarks, are used to indicate other dull characteristics and the reason the bit was pulled.

5. Besson et al, reference 1.

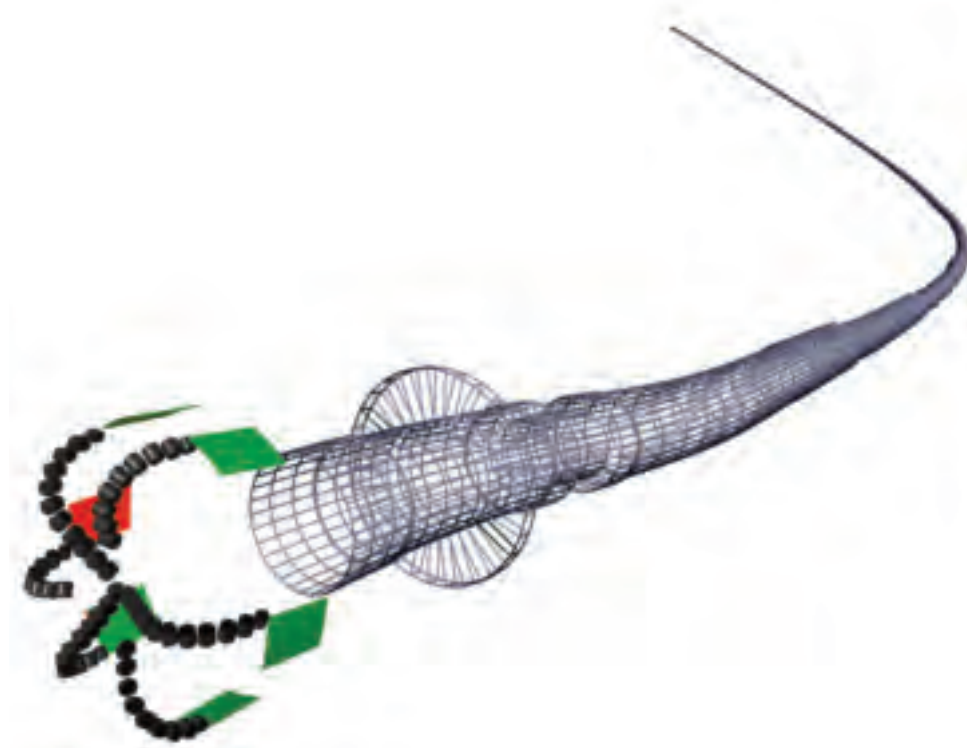
6. Bentson HG and Smith HC: "Rock-Bit Design, Selection and Evaluation," paper API 56-288, presented at the Spring Meeting of the API Pacific Coast District, Division of Production, Los Angeles, May 1956.

7. Hampton SD, Garris S and Winters WJ: "Application of the 1987 Roller Bit Dull Grading System," paper SPE/IADC 16146, presented at SPE/IADC Drilling Conference, New Orleans, March 15–18, 1987.

8. Hampton et al, reference 7.

9. Brandon BD, Cerkovnik J, Koskie E, Bayoud BB, Colston F, Clayton RI, Anderson ME, Hollister KT, Senger J and Niemi R: "First Revision to the IADC Fixed Cutter Dull Grading System," paper IADC/SPE 23939, presented at the IADC/SPE Drilling Conference, New Orleans, February 18–21, 1992.

Brandon BD, Cerkovnik J, Koskie E, Bayoud BB, Colston F, Clayton RI, Anderson ME, Hollister KT, Senger J and Niemi R: "Development of a New IADC Fixed Cutter Drill Bit Classification System," paper IADC/SPE 23940, presented at the IADC/SPE Drilling Conference, New Orleans, February 18–21, 1992.



^ FEA mesh. An FEA mesh represents a modeled body—in this case a drillstring—with mesh elements that connect at the nodes (black lines) to critical components affecting drilling performance. This mesh is used in the IDEAS program to optimize bit cutting structures (black cylinders). In this instance, red and green patches indicate that side forces on the bit during this simulation are being imposed on the gauge of one blade (red), more so than on the other five (green).

to the system accordingly before drilling the next section or next well. The process was repeated in successive attempts to incrementally improve ROP or bit life.

In some cases, these changes resulted in little progress from one well to the next, and the driller had to restart the process. More commonly, the iterative method enjoyed at least partial success as ROP was increased or the bit was able to drill more footage before it had to be replaced. Still, well histories abound in which little improvement was seen even after many iterations, or, if the iterative process was successful, it was only after many such trial-and-error cycles. An iterative approach is particularly handicapped when the first well includes little offset data or the drilling program includes only a few wells.

The iterative process for developing optimal bit and BHA configurations is also hampered by several factors inherent in the process. Engineers of differing experience draw different conclusions from essentially the same wear patterns; some engineers, for example, may arrive at the cause of a particular wear pattern after making false assumptions. The most common of these assumptions is that drillstring weight is efficiently transferred to the bit. WOB directly

impacts ROP. An engineer may assume that poor bit selection is hampering ROP when in fact WOB, which is a function of BHA design, is actually less than calculated.¹⁰ Conversely, when WOB is too high, the drillstring and BHA may bend, leading to an overgauge hole and destructive lateral vibrations as the angled bit engages and cuts away the borehole wall.

In 1987, efforts were made to correct this possible pitfall with the introduction of BHAP, a BHA performance prediction computer program. BHA design decisions include the type, placement, shape and size of all components above the bit. Before the introduction of BHAP, engineers relied on mathematical models that used descriptions of the BHA components to predict WOB. These models were two-dimensional, used a constant wellbore curvature and were static.¹¹

Although designed to be simple to minimize computer run time, BHAP was an improvement over previous practices that tended to view bit performance in isolation. More complex modeling awaited the arrival of computing power that could, at reasonable speed and cost, handle massive volumes of data and calculations.

An Elemental Answer

When BHAP was introduced, engineers had at their disposal a powerful tool for creating a more comprehensive and more accurate description of the drillstring. In the 1940s, scientists and mathematicians seeking to analyze vibrations in complex machinery had introduced the world to finite element analysis (FEA). FEA involves 2D or 3D modeling and uses a complex system of nodes to create a grid called an FEA mesh. This FEA mesh is populated with the material and structural properties that define how the system will react to loading conditions. Throughout the material, the density of the nodes depends on the anticipated stress levels of a particular area. To concentrate computer power where it is needed, regions receiving large amounts of stress usually have a higher node density than those experiencing little or no stress. From each node, a mesh element extends to each of the adjacent nodes (above).¹²

By the 1970s, FEA was commonly used by mechanical engineers, although its application remained limited to a few users who could afford the necessary computing power. As a consequence, most drilling optimization computations

relied predominantly on offset well data rather than FEA techniques to plan wells. These programs' attempts to assess and predict drillstring and bit behavior were restricted to static or steady-state analysis designed to understand a specific part of the system at a particular moment. These assessments were most useful as postmortem descriptions of drilling system failures and identified only a fraction of the problem.¹³

To optimize bit and drillstring component selection and placement, engineers needed to understand the dynamic interaction of all components as drilling progressed. This finally became feasible when high-powered, fast computers became widely available in the 1990s. Engineers began, relatively quickly and at reasonable cost, to digitally recreate and analyze drilling systems and their behavior over time. Rather than performing expensive, time-consuming field trials, engineers—now armed with dynamic modeling capabilities—began to pinpoint the cause of drilling system failure and then test solutions using a virtual prototype.

Dynamic models may be run to analyze the behavior of individual components, such as the bit or BHA, or they may address the entire system. The net forces and moments acting on a bit are obtained from vector sums of the contributions of individual cutters. Fixed cutter bit forces are obtained from laboratory test data; roller cone insert forces are based on simple crushing and shearing models. The equations of motion are integrated using a variable-timestep procedure.¹⁴ Six degrees of freedom (DOF) are allowed for the bit body: three translations and three rotations. For roller cone bits, DOF functions may be toggled off to simulate a seized cone.¹⁵

10. Williamson JS and Lubinski A: "Predicting Bottomhole Assembly Performance," paper IADC/SPE 14764, presented at the IADC/SPE Drilling Conference, Dallas, February 10–12, 1986.

11. Williamson and Lubinski, reference 10.

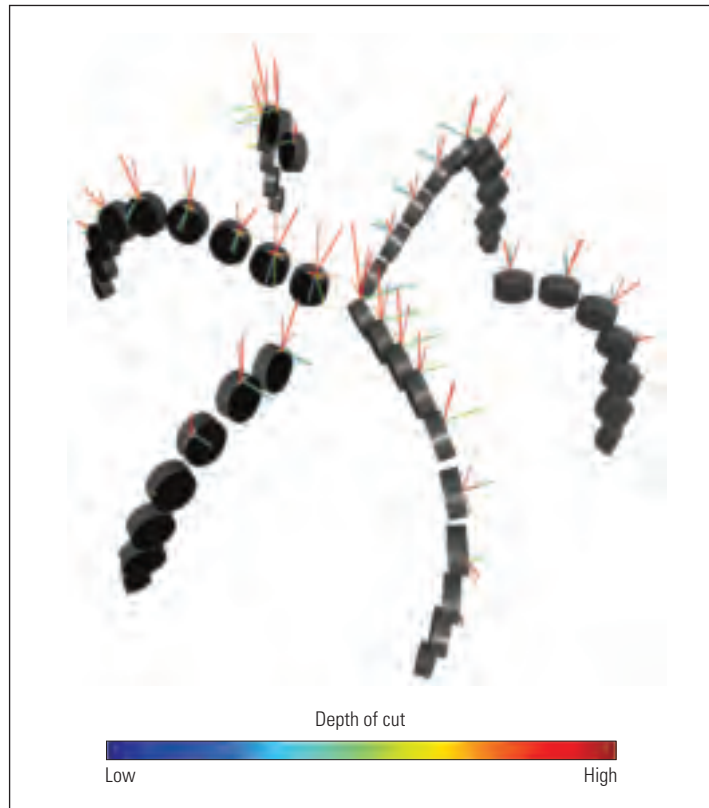
12. "Introduction to Finite Element Analysis," http://www.sv.vt.edu/classes/MSE2094_NoteBook/97ClassProj/num/widas/history.html (accessed February 8, 2011).

13. Frenzel MP: "Dynamic Simulations Provide Development Drilling Improvements," paper OTC 19066, presented at the Offshore Technology Conference, Houston, April 30–May 3, 2007.

14. Algorithms using a variable-timestep procedure continuously monitor the accuracy of the solution during the course of the computation, and adaptively change the timestep size to maintain a consistent level of accuracy. The step size may change many times during the course of the computations; larger time steps are used when the solution is varying slowly, and smaller steps are used when the solution varies rapidly.

15. Dykstra MW, Neubert M, Hanson JM and Meiners MJ: "Improving Drilling Performance by Applying Advanced Dynamics Models," paper SPE/IADC 67697, presented at the SPE/IADC Drilling Conference, Amsterdam, February 27–March 1, 2001.

16. Dykstra et al, reference 15.



^ Cutter design. Bit design engineers begin with an initial cutting structure layout (black cylinders) modeled within the IDEAS program. Each cutter on each blade is analyzed using force vectors (green and red lines) representing components of the cutting force. Vector length represents relative force magnitude. Color represents depth of cut according to the scale. Engineers use this information to position each cutting structure in terms of height above the blade surface, its radius from the bit center, the back rake and side rake angles, the size of the cutter and its profile angle. Back rake is the angle of cutter face in reference to bottomhole, and side rake refers to its angle relative to the radius of the bit face.

Dynamic Modeling

Engineers first applied dynamic modeling to drilling operations to improve efficiency and protect expensive downhole components from destructive toolstring vibrations. This method included planning, real-time monitoring and detailed postjob analysis.

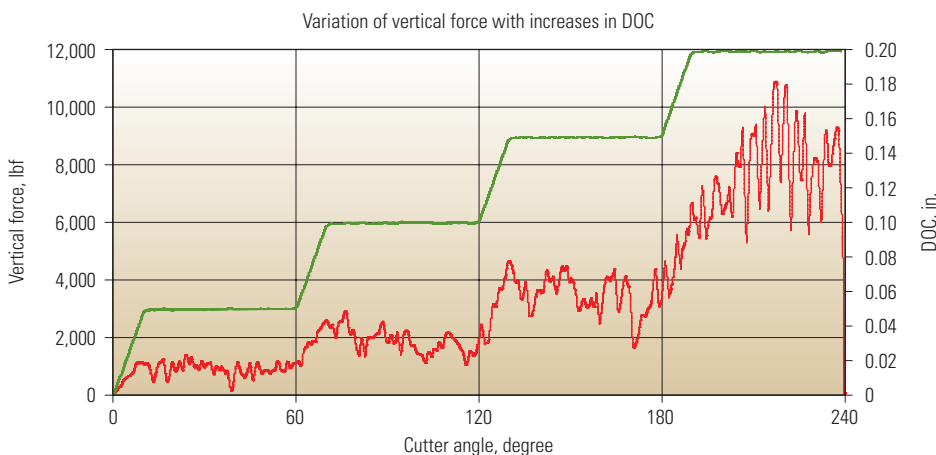
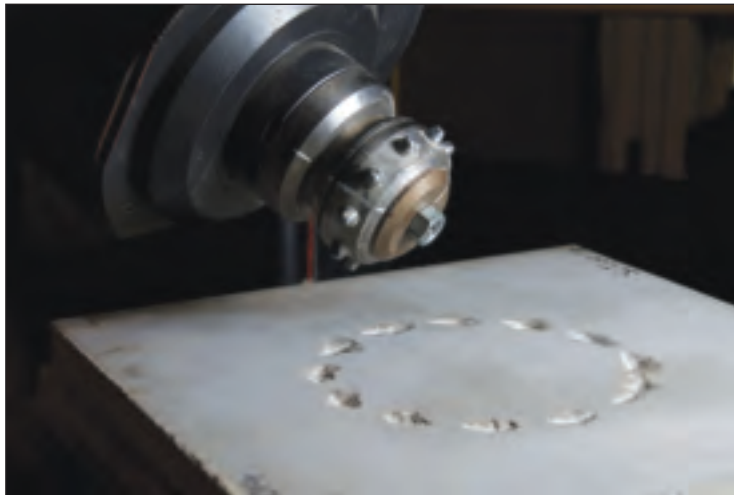
During planning, engineers identify likely dynamic dysfunctions that cause bit bounce, stick-slip and bit- and BHA-whirl. Mathematical models are then used to design BHAs based on directional control and desired ROP and to counter expected dysfunctions. Downhole and surface sensors monitor dysfunction-related vibrations. Based on measurements from the sensors, model results and prior experience drilling in the field, engineers adjust drilling parameters to optimize ROP and minimize destructive vibrations.¹⁶

Usually, bit dynamic stability is ascertained through laboratory tests that determine the ROP or WOB that will force the bit to become unstable

at a given rotary speed. Bit-dynamics modeling allows the manufacturer to eliminate poor designs before bits are built and to determine optimal rotary speed ranges for a given design and downhole environment.

Drillstring-dynamics simulations are based on finite element methods. Like bit-dynamics models, each node of the BHA model has six DOF and the equations of motion are integrated using a variable-timestep procedure. When drillstring and bit-dynamics models are coupled, dysfunctions that hinder drilling performance can be predicted and avoided.

In the 1990s, Smith scientists introduced a comprehensive FEA program aimed at accurately modeling the total drilling system. The IDEAS integrated dynamic engineering analysis system predicts drillbit performance as part of a total drilling system (above). Based on laboratory-derived drilling mechanics and physical input



^ Scrape and indentation tests. A roller cone insert (*top*) scrapes a sample rock—Carthage marble here—with 3,000-psi [20.7-MPa] unconfined compressive strength (UCS) at various depths-of-cut (DOCs). In the graph (*bottom*) measured vertical force (red) and DOC (green) are recorded for various cutter angles. This information is then loaded into the IDEAS application as a rock file, which is specific to this rock and cutter combination.

data, it uses equipment that accurately characterizes the cutting structure's interactive mechanics during crushing and shearing across a broad range of rock samples.

These input data, captured from a series of indentation and scrape tests, are acquired under laboratory-controlled pressures to replicate the dynamic interaction between a bit cutting structure and a specific rock sample (*above*). The experiments quantify actual cutter forces and cuttings generated in terms of magnitude and orientation as a function of both rock failure mechanisms and rock removal rates. These data are then used for the design analysis in lithologies comparable to the specific field application. In some cases, these tests are conducted on actual core samples from offset wells near the new well. The simulation model can incorporate either roller cone or fixed cutter bits.

Also in the early 1990s, Smith developed the DBOS drillbit optimization system, which allows engineers to characterize each target interval in terms of the unconfined compressive strength (UCS) of the rock, an abrasive index and an index of the rock's impact on cutters. Based on this assessment, the system then defines the appropriate bit type and features with which to drill each interval of depth change. Over the years, Smith has built a database of DBOS studies, which includes bit types and formations drilled. The DBOS formation characterization database, coupled with the IDEAS simulations, enables engineers to select the appropriate rock test files for a given application.

The rock and cutter mechanics data from the IDEAS laboratory are imported into a virtual drilling environment along with information

about the specific drill bit to be evaluated. This assessment includes the following elements:

- precise location, material properties and dimensions of cutters
- bottomhole component dimensional data and the physical characteristics of each BHA element
- geometry of the proposed wellbore
- planned operating parameters.¹⁷

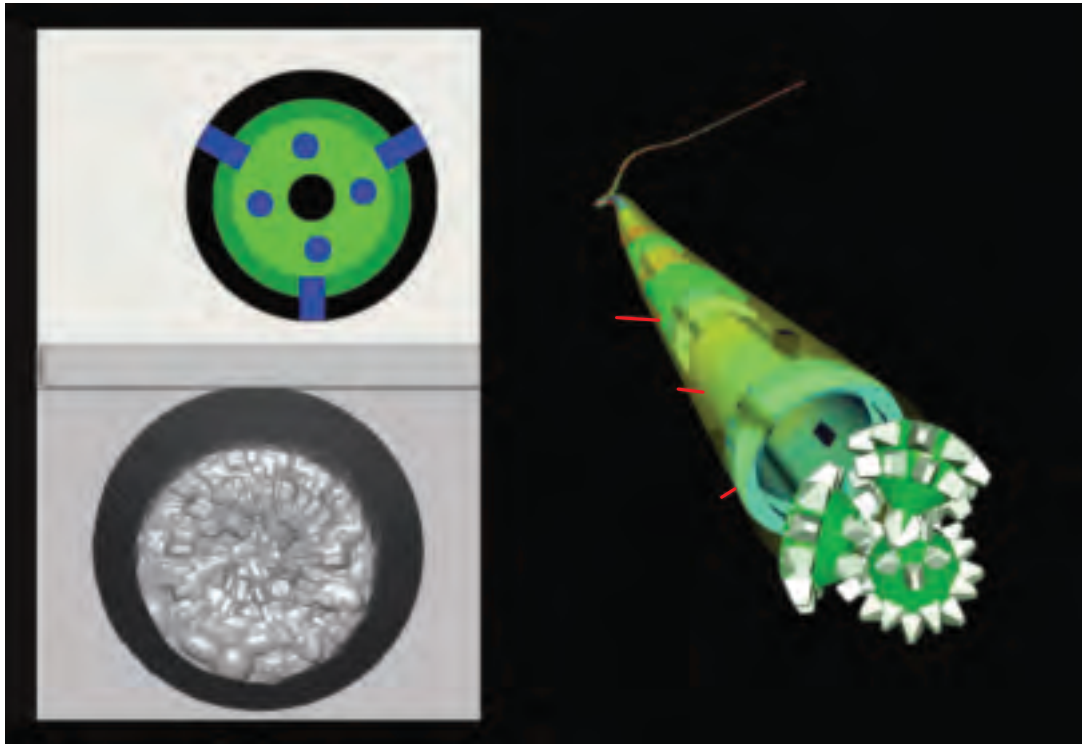
Bit performance can then be examined in a confined environment during initial design development. The process also predicts bit performance while considering the BHA, well geometry, drilling parameters and lithology variations. All of this is done in a dynamic simulation that considers influences on the bit that are as close as possible to those it will encounter while drilling.

The resulting outputs enable designers to match projected bit performance with drilling objectives, such as ROP, footage drilled per bit and specific directional characteristics. Designers use the IDEAS software as an interactive tool to test the effects of iterative changes to bit features on overall performance in specific applications. The modeling programs reveal how subtle changes in a cutter's position and orientation significantly affect drilling performance and dynamic stability of the bit and BHA. The engineer can quickly optimize design and then use the modeling process to certify the performance capabilities of each bit through a dynamic simulation and modeling methodology.¹⁸

Looking for Trouble

In 2004, Smith commercialized the i-DRILL engineered drilling system. This engineering service uses the IDEAS program platform to quantitatively identify the forces, vibrations and ROP for a specific complex drilling system over time. The system tests the dynamic effects of bit type, BHA design, drive mechanism and drilling parameters as a function of hole size and formation characteristics. This FEA drilling simulation model uses more than one million lines of code to accurately describe the total drilling system.

The simulation is created by combining a bit-rock cutting model, based on extensive laboratory testing, with FEA of the bit and drillstring. Design engineers then evaluate the behavior of various combinations of drill bits, drillstring components and configurations, surface parameters and overbalance pressures. The dynamic behavior of the entire drilling system can be analyzed through multiple geological formations of varying compressive strength, dip angle, homogeneity and anisotropy to gain optimal drilling performance through formation transitions.



^ Modeling milled-tooth bit operation. This view of a milled-tooth bit application generated by i-DRILL software includes displacement and contact forces at the rotary steerable system (RSS) pads (blue rectangles, *top left*). In this case, a cross-sectional view of the RSS oriented along the drillstring axis shows the tool to be centered in the hole. This indicates that there is no contact force on the pads, which means the wellbore trajectory is not being changed at the instant the data are captured. The pattern made by the bit on the bottom of the hole is shown (*bottom left*) as are critical BHA–wellbore wall contact points along the BHA (red lines, *right*).

The i-DRILL process integrates offset well data, surface and downhole measurements and knowledge of available products and applications as part of the design process. It also considers detailed geometric input parameters and rock mechanics data. These inputs enable engineers to simulate a specific drilling operation and thus evaluate and, through dynamic analysis, correct root causes of inefficient and damaging BHA behavior. The i-DRILL system creates dynamic drilling simulations that help engineers visualize the downhole environment prior to drilling; this is in contrast to engineers having only static analyses, which provide just a small slice of data for a fixed point in time.

The i-DRILL modeling process begins by using the available offset well data to calibrate the simulation software for each application. The dataset may include the following:

- details regarding the physical characteristics of the entire drillstring, the BHA and the drill bit
- directional surveys and caliper logs to characterize the hole geometry
- surface and downhole operating parameters such as WOB, torque and rpm
- mud log and wireline log data to evaluate the formations being drilled.

Designers use this information to build a computer model of the offset drilling assembly, the formations and the wellbore (*above*). The program simulates the operation of the drilling assembly as a function of time. Because it allows analysis of the specific target lithology and the behavior of each BHA component, any suspect behavior is identified, quantified and illustrated using the system's advanced graphics capabilities. Simulation video clips accurately illustrate what would occur downhole. The process identifies damaging and efficiency-reducing dysfunctions such as high rotary steerable system (RSS) contact forces, bit whirl and excessive bending moments.

Once the underlying causes of undesirable drilling characteristics are identified, the engineer can reconfigure the modeled drilling assembly and use simulation analyses to correct the problems. Corrective actions can include switching to a different drill bit, exchanging stabilizers for reamers, repositioning individual BHA components, changing operating parameters or combinations of changes that will produce significant performance improvements.

Last, the software generates a comprehensive report documenting the findings and analysis process, which designers can then present to the

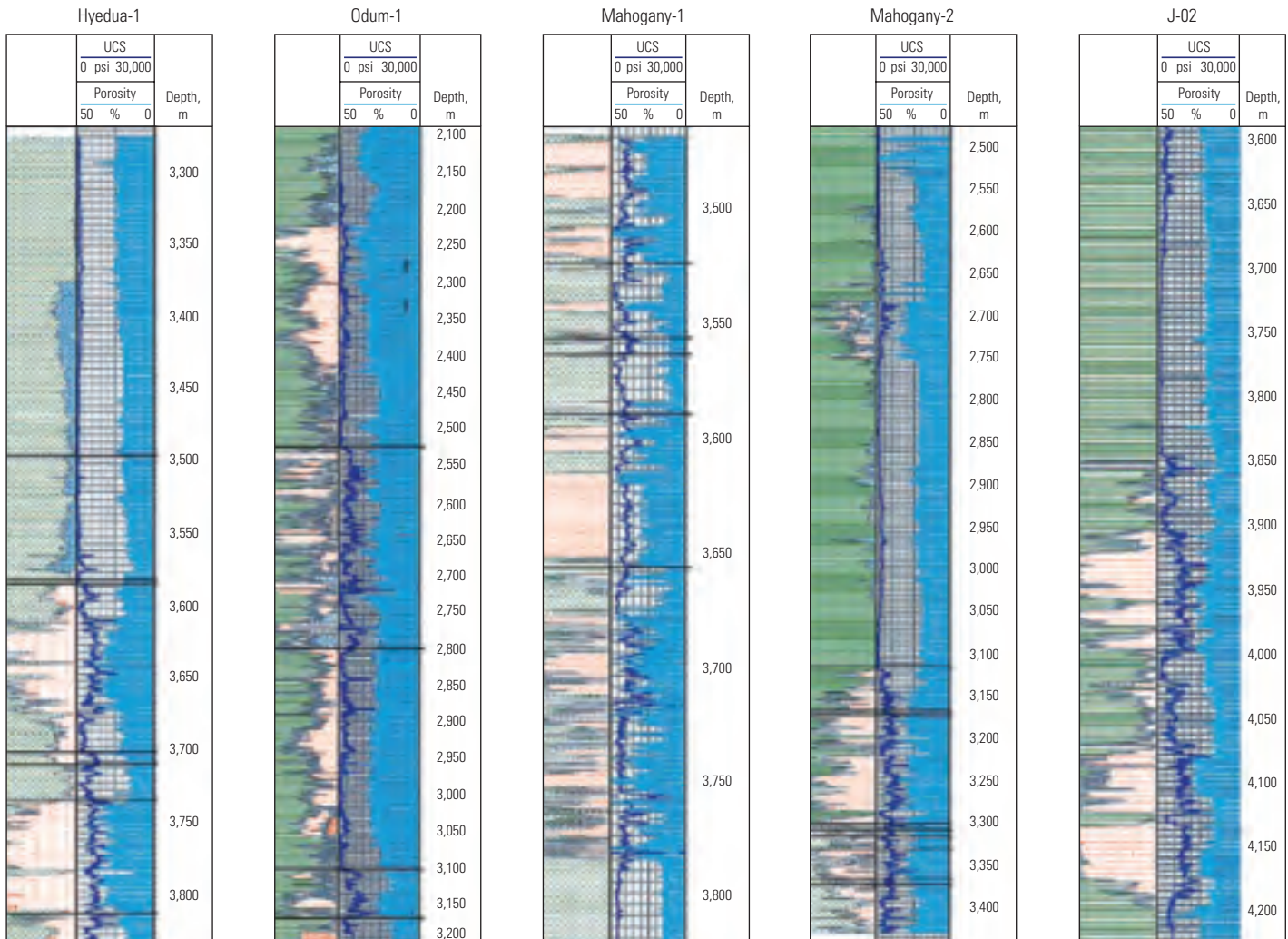
operator. It contains the results of each simulation, identifying all potential changes that could be made to the drilling assembly and the effect that each would have on drilling performance. The operator can then select the best option to meet drilling objectives, minimize problems and improve performance.¹⁹

Dynamic modeling systems allow engineers to process a multitude of simulations representing any combination of drillbit options, drilling assembly components, drillstring design, component placement and operating parameters. Because the method is highly accurate, engineers are able to quantitatively evaluate various scenarios and then choose a solution in which a specified performance will be achieved in the drilling operation. The method helps identify operational technical limits, which avoids NPT, and eliminates inefficiencies resulting from operating too far below the technical limits. It also helps the operator avert needless trips to change bits and BHAs that are the result of using

17. Garrett I, Teggart B and Tetley N: "FEA Modeling System Delivers High-Angle Well Bore Through Hard Formations," *E&P* 83, no. 9 (September 2010): 68–71.

18. Garrett et al, reference 17.

19. Garrett et al, reference 17.



^ Jubilee field well logs. Interpretations of sonic and gamma ray logs of four 12¼-in. sections of Jubilee wells drilled at different depths were used to determine lithology and UCS. The first track, lithology, includes shale (green), sandstone (red) and marl (blue). The second track shows UCS (dark blue line) with porosity (aqua shading).

trial-and-error methods to solve particular drilling challenges.

Dynamic modeling was used in 2007, after Tullow Oil plc drilled successful exploration wells—Mahogany-1, Mahogany-2 and Hyedua-1—offshore Ghana, West Africa, which resulted in the discovery of the Jubilee field. Results from three appraisal wells drilled in 2008 confirmed that the field is a continuous stratigraphic trap.

The Jubilee field is one of only a few deepwater developments in the world containing hard and abrasive formations through the reservoir sections. Engineers identified these challenging formations while drilling the first four wells in the region. With log data from the first three test wells, a rock mechanics program quantified the formation's UCS between 6,000 psi and 10,000 psi [41.4 MPa and 68.9 MPa] with turbidite stringers as high as 25,000 psi [172 MPa] (above).

Due to the difficulties encountered on the first four wells, the operator commissioned a full i-DRILL study based on all the available data. This study recommended an initial seven-bladed PDC bit to drill to a planned core point. After coring, a more durable nine-bladed PDC bit was recommended. When the operator drilled the first appraisal well—Hyedua-2—the first bit wore quickly once it began to penetrate the reservoir, further confirming the abrasive nature of the reservoir.²⁰ The more durable bit was run below the cored section, but after it drilled only a short distance, it was pulled in response to low ROP. Once retrieved, it too was found to be badly worn. The i-DRILL process successfully predicted which bits would yield a stable system; this allowed engineers to turn their attention more specifically to bit durability.

Using an FEA-based dynamic modeling system, engineers then began a series of virtual tests to identify a PDC bit optimized for the reservoir section. While engineers analyzed the results of the Hyedua-2 well and developed an improved bit and cutter design, the operator drilled three more development wells and tested several bit designs.

An optimized bit was manufactured in 2009. At the same time, Smith developed the proprietary, highly abrasion-resistant ONYX PDC cutter, which was incorporated into the optimized bit. On its first application in the J-02 well, it drilled the entire hard and abrasive 12¼-in. section in a single run. Further bit refinement improved performance. Engineers then turned their attention to the BHA design in an effort to reduce high vibration levels that were causing LWD tool failure, which in turn forced the operator to run time-consuming wireline logs.

Well name	Number	Spud date	Bit type	Out, m	Drilled, m	Hours	ROP, m/h	Inclination, degree	BHA	Bit Grade									
										I	O	C	L	#1	#2	#3	G	O	R
Hyedua	02	Oct. 25, 2008	PDC 6	3,393	996	56.0	17.8	14	BHA 8	2	8	RO	S	X	X	X	1	LT	CP
Hyedua	02	Oct. 25, 2008	PDC 4	3,565	57	18.5	3.1	Vertical	Rotary	1	2	WT	S	X	X	X	1	NO	PR
Hyedua	02	Oct. 25, 2008	TCI 527	3,663	98	48.5	2.0	Vertical	Rotary	5	4	BT	A	E	E	E	2	WT	TD
Jubilee	02	Apr. 11, 2009	PDC 5	4,215	1,135	126.6	9.0	38	BHA 8	3	4	WT	A	X	X	X	1	CT	TD
Jubilee	05	July 22, 2009	PDC 5	4,192	1,702	80.5	21.1	49	BHA 12	1	2	WT	S	X	X	X	1	NO	TD
Jubilee	11	Aug. 08, 2009	PDC 5	4,213	1,481	90.5	16.4	40	BHA 12	2	3	WT	S	X	X	X	1	NO	TD
Jubilee	12	Aug. 31, 2009	PDC 5	4,292	1,349	71.1	19.0	44	BHA 12	3	8	WT	S	X	X	X	2	RO	TD

TCI = tungsten carbide insert. Bit grading code: I = inner cutting structure; O = outer cutting structure; C = cone; L = location; S = shoulder; A = all areas; #1, #2, #3 = bearing; E = seals effective; X = no bearings; G = gauge; O = other dull characteristics; LT = lost cutter; NO = no dull characteristics; WT = worn cutters; RO = ring out; R = reason pulled; CP = core point; PR = penetration rate; TD = total depth, casing point.

^ Run details in the 12¼-in. section. Compared to the averages from offset wells (brown), the newly designed PDC bit run in J-05, J-11 and J-12 (green) drilled 165% more footage with an ROP increase of 122%. The bit was in good condition when pulled.

They approached the problem by studying the most recent offset well, the J-02, in a follow-up i-DRILL study with a focus on stick-slip and lateral vibrations. Engineers first identified conditions within the well that led to stick-slip and bit whirl and then replicated those conditions in a simulation. After they better understood the drilling dynamics of the well, engineers ran simulations using varying BHA, WOB and rotation speed.

From these results they recommended changes in BHA configuration and optimized operating ranges for WOB and rotation speed; they recommended the same bit, but with a motor to assist a push-the-bit RSS. This was used successfully on the next three wells, J-05, J-11 and J-12. Further bit optimization efforts focusing on drilling parameters allowed engineers to maintain these successes using RSS only.

These recommendations were applied to the J-05 well, which required a tangent section with a 49° inclination before reaching TD at 4,192 m [13,753 ft]. The results include an ROP improvement from 8.9 to 21.1 m/h [29.2 to 69.2 ft/h] and commensurate savings in rig time of about US\$ 1 million/day. When retrieved, the bit, LWD tool and RSS were in good condition due to reduced vibration levels compared with those in J-02. Drilling performance from the three offset wells showed that the new PDC bit drilled 165% more footage with a 122% increase in ROP while drilling the reservoir interval in a single run (above).²¹

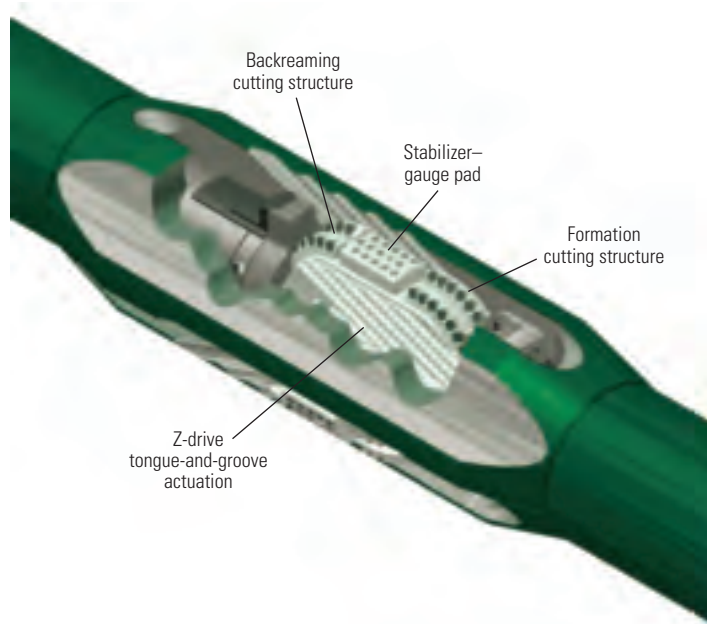
This system was used on the next two wells, J-11 and J-12. Further bit optimization efforts focusing on drilling parameters allowed engineers to maintain these successes using RSS only.

Since July 2009, with optimized BHA and parameters, the operator has used bits of the same design to drill all but one 12¼-in. section in a single run.

Special Needs Cases

Some drilling scenarios are inherently more difficult to optimize than others. For example, deep wells often present drillers with a particularly challenging scenario in which the initial hole

must, while it is being drilled, be enlarged, or opened, beyond the size of the bit. To accomplish this, the BHA often includes an underreamer-hole opener tool located above the bit (below). Once drilling commences in a hole section to be

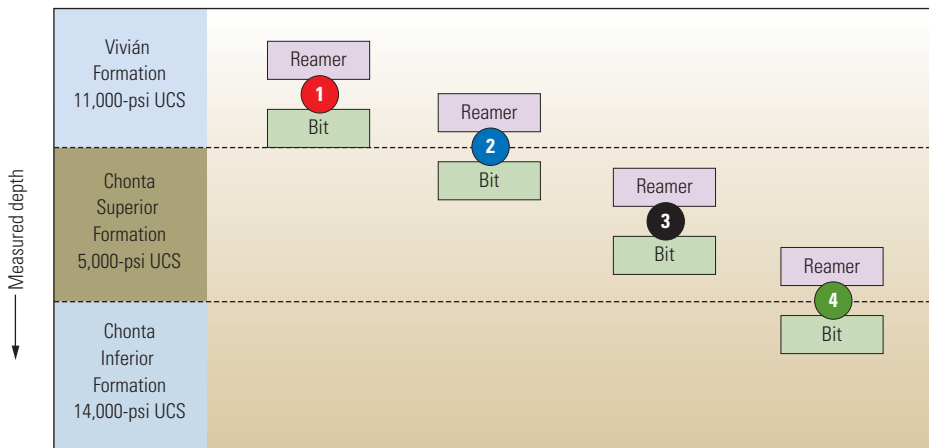


^ Underreamer-hole opener. An underreamer is designed so that its cutting structure may be expanded to a size greater than the diameter of the pilot bit once they have both exited the casing shoe and entered the interval to be opened. This concentric reamer includes a one-piece cutter block and extension mechanism design. The tongue-and-groove actuation system traverses beneath the PDC formation cutting structure blocks and opens it to a preselected diameter maintained by the simultaneously opened stabilizer-gauge pad. At the same time, three backreaming cutting structures are locked in place to allow the reamer to open the hole while tripping out, if required. The blocks are locked in place by the tool's hydraulic system. The single-piece body design increases the tool's torque and load-carrying capacity, ensuring it can efficiently handle the heavy weight of the rotary steerable system BHA.

20. Murphy D, Tetley N, Partin U and Livingston D: "Deepwater Drilling in Both Hard and Abrasive Formations; The Challenges of Bit Optimisation,"

paper SPE 128295, presented at the SPE North Africa Technical Conference, Cairo, February 14-17, 2010.

21. Murphy et al, reference 20.



▲ Four critical scenarios. Engineers identified four critical situations encountered while drilling the tangent section through the Vivián, Chonta Superior and Chonta Inferior formations with a 12¼-in. reamer and 10%-in. pilot bit. The critical scenarios—during which damaging vibrations are most likely to occur—are while the bit and reamer are in Vivián (1), the reamer is in Vivián while the bit is in Chonta Superior (2), the bit and reamer are in Chonta Superior (3) and while the reamer is in Chonta Superior and the bit is in Chonta Inferior (4).

enlarged, engineers send a signal that expands the underreamer's blades, creating a cutting tool of larger diameter than the internal diameter of the previous casing string. The object of the operation is to forestall reduction of wellbore diameter as numerous, successively smaller casing strings are installed across transitional zones encountered while drilling deep wells. This strategy is also employed extensively in deepwater operations in which many casing strings must be used to control drilling fluid losses as the pore-pressure–fracture-gradient window quickly narrows. A larger diameter wellbore also addresses the challenge of small drilling windows through reduced friction pressures in the annulus, creating a lower equivalent circulating density (ECD). The intended result is a sufficiently large internal clearance through the production casing string to accommodate all necessary completion equipment.

Underreaming while drilling may be problematic in some situations. In combination with downhole motors or rotary steerable assemblies, the reamer must be strong enough to hold the added weight of the steering assembly hung below it and yet remain sufficiently pliant to deliver a quality wellbore through sometimes acute trajectory changes. Perhaps greater challenges to the BHA and bit designer, however, are difficulties that arise when the reamer and bit are drilling in formations of differing hardness. This difference may cause them to drill at different

speeds, generating torsional and lateral vibrations in the drillstring.

In the Pagoreni field, operator Pluspetrol was experiencing vibration problems, which were resulting in unacceptably low ROP and the destruction of expensive downhole measurement tools. The Pagoreni field is located onshore in a folded Andean thrust belt in the southern portion of Peru's Ucayali river basin. Pluspetrol began developing the field in May 2006. The deviated Pag1001D well reached 10,300 ft [3,139 m] MD about 1 mi [1.6 km] southeast of the surface location and confirmed the presence of commercial quantities of wet gas in the Upper Nia formation. This led the operator to launch a six-well development program aimed at recovering the field's estimated 3.5 Tcf [99.1 billion m³] of proven and probable recoverable reserves.

The vibration problems developed in the first three wells while the operator was drilling a 10%-in. pilot hole that was opened to 12¼-in. using an expandable underreamer. In these wells, the problems were stick-slip and high axial and lateral vibrations while the tangent sections were being drilled. Trial-and-error approaches to BHA changes provided some relief from the axial and lateral vibrations but exacerbated stick-slip severity.²²

The troublesome section included the following stratigraphic sequence:

- Vivián Formation—hard, fine- to very fine-grained, friable quartz sandstone of 11,000-psi [75.8-MPa] UCS

- Chonta Superior—soft calcareous shale and clay of 5,000-psi [34.5-MPa] UCS
- Chonta Inferior—hard limestone layers of 14,000-psi [96.5-MPa] UCS.

Unable to overcome the drilling dysfunctions through iterative processes, the operator requested that the i-DRILL engineering group at Smith optimize the BHA design, including PDC bit selection, for its fourth well, the Pag1004D. The team began by organizing offset data and information on drilling practices from the three previous problem wells—Pag1001D, Pag1002D and Pag1003D.

These offset data were input into the BHA modeling program. The model included the PDC bit, RSS, LWD, expandable reamer and drillstring to the surface drive system. All drillstring dimensions and materials from offset wells, as well as a hole caliper measurement from offset wells, were incorporated into the model. The model was then calibrated using other offset data, including rotation speed, WOB, surface torque and hook load, as well as data from downhole measurements.

Simulations were run and adjusted repeatedly until the offset conditions were duplicated to within a statistical match. The simulations allowed engineers to view the interaction of the previous systems and the boreholes and determine the root cause for poor drilling performances in the first three wells. The resulting virtual model was then tested to predict the effects of different bit types, BHA designs, drive mechanisms and operating parameters as a function of hole size and lithology.

A series of virtual cases was run to determine the optimal PDC bit profile, blade and cutter count, gauge length, bottomhole patterns and force balance on four bits. Laboratory tests helped determine the most appropriate cutting structures in terms of aggressiveness when used in combination with the 12¼-in. bit with 13-mm [0.51-in.] cutters. Smith technicians were able to make this determination using the IDEAS laboratory to simulate the confining pressure of the specific formations to be drilled. ROP potential was then calculated using an FEA model that considers precise dimensions and properties of the cutting structure, rock hardness, or UCS, lithology and confined pressure based on laboratory tests.

Engineers modeled BHA components to test various scenarios aimed at reducing vibrations. For the Pagoreni field, the i-DRILL team identified four critical scenarios with vibration-inducing potential that could be encountered

while drilling transition zones between the Vivión, Chonta Superior and Chonta Inferior formations (previous page). These include the following situations:

- bit and reamer in Vivión
- reamer in Vivión, bit in Chonta Superior
- bit and reamer in Chonta Superior
- reamer in Chonta Superior, bit in Chonta Inferior.

To better understand the dynamics involved in the four scenarios, engineers conducted five in-depth virtual analyses using the four candidate bits in combination with the underreamer:

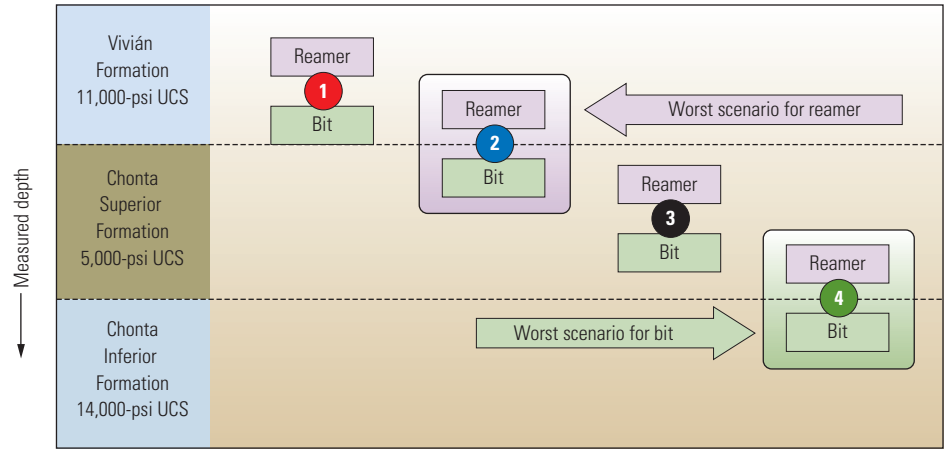
- weight distribution (WOB and weight on reamer) versus ROP
- lateral vibration (bit and reamer) versus ROP
- torque vibration (bit and reamer) versus ROP
- average torque (bit and reamer) versus ROP
- risk of stick-slip versus ROP.

Based on these analyses, engineers concluded that the most critical scenario occurred when the bit was in the soft Chonta Superior Formation and the reamer in the hard Vivión Formation. That was also the section in which the reamer was least efficient. The worst case for the bit, however, occurred when the reamer was in the Chonta Superior and the bit was in the harder Chonta Inferior (above right).²³ Overall, the optimal method to balance the requirements of maximum ROP and reduced vibration through the four challenging scenarios was to use a rotary steerable-compatible six-blade bit design.

Shale Gas Drilling Challenges

Massive gas reserves are being discovered in shale formations around the world. Because they are of extremely low permeability, these shale reservoirs are accessed using long horizontal wellbores, usually drilled with tungsten-carbide PDC bits. The formation is then opened through multiple hydraulic fractures.

In the Marcellus shale of the northeastern US, operators found that drilling long lateral wells with conventional PDC bits resulted in premature bit failures and short runs because of bit balling, poor directional behavior and loss of toolface control. Balling was causing plugged bit nozzles and packed bit bodies (right). Cuttings were not being carried back up the annulus but instead were

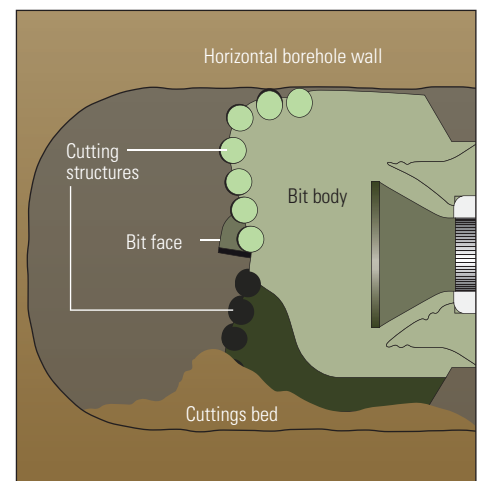
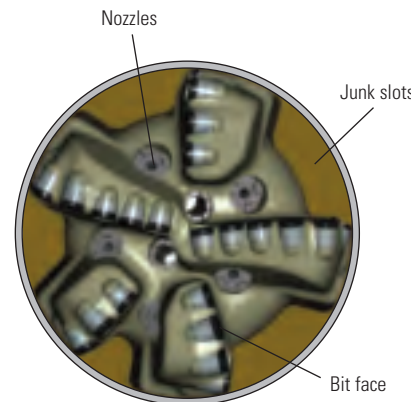


Transition drilling conclusions. Based on their analysis, engineers concluded that scenario 2, when the bit is in the relatively soft Chonta Superior Formation and the reamer is in the hard Vivión Formation, is the most critical of all scenarios. Scenario 2 is also the least efficient for the reamer. The worst scenario for the bit is when the reamer is in the soft Chonta Superior and the bit is in hard Chonta Inferior. Based on the resulting scores, the modeling suggested the best bit for each scenario. The study was based on a normalized results equation in which each selected drilling parameter was assigned a specific weight according to the operator importance. In this specific project, an equal weight distribution was made for average ROP, bit, reamer and surface stick-slip, bit and reamer lateral vibration and the change in downhole rotation rate.

accumulating around the bit, creating a potential for stuck drillpipe. All this dramatically reduced ROP and increased drillstring stick-slip.

Because the Marcellus shale is a relatively new play, engineers at Smith had to design a bit while having little offset data at hand. Available

history indicated numerous operators with differing drillstring and BHA and bit configurations, making analysis difficult. Drawing on the IDEAS system, however, engineers at Smith offered a design that did improve ROP but did not fully address toolface control and nozzle plugging.



Nozzle plugging. A common problem in extended-reach shale drilling is the tendency for cuttings to collect in front of the bit face because the drillstring is idle while rig workers are making connections and the pumps are off. If the design of the body and junk slots does not allow for efficient movement of cuttings past the bit when circulation resumes after pumps are turned back on, a buildup of cuttings can occur and push into and plug the nozzles (left). Cuttings can likewise be pinched between the hole and the bit gauge, which prevents proper hole cleaning (right).

22. Cassanelli JP, Franco M, Perez J, Paez LC, Pinheiro C and Frenzel M: "Dynamic Simulation: Solving Vibration/ Stick-Slip Issues Achieves Record ROP, Pagoreni Field, Peru," presented at the Sixth International Seminar on Exploration and Exploitation of Hydrocarbons (INGEPET) Lima, Peru, October 13–17, 2008.

23. Cassanelli et al, reference 22.



▲ Bit solution for the Marcellus shale. Since bit body erosion is of less concern while drilling shales than while drilling more abrasive sands, the bit body could be made of steel. This allowed the designers to use a more streamlined body (*top right*) because the less brittle steel blades could be made longer and thinner without being subject to failure due to impact breakage. Steel also permits construction of a shorter bit (*bottom right*) than is possible with a matrix-body bit (*bottom left*), which enhances its ability to drill through extreme angle changes using a drilling motor.

The initial attempt created a baseline from which engineers could design a second bit. This second iteration met steerability requirements of directional drillers and produced an acceptable ROP through the build section. This made it easier, quicker and less costly to create a curve in the well path at the desired angle, azimuth and build rate.

However, ROPs through the 2,000- to 3,000-ft [610- to 914-m] lateral sections, which represented the greatest portion of drilling expense, were less than satisfactory. Engineers knew that drilling with rigs typically available in North America was being slowed by poor hole cleaning due to low hydraulic energy at the bit, which is common when drilling horizontal wells in shale

formations. Design iterations that reoriented and repositioned bit nozzles did little to alleviate the problem.

Technicians at the Smith IDEAS laboratory could not obtain actual samples of the field rock to be drilled but were able to use DBOS analysis to match the Marcellus rocks with the Wellington and Mancos shales stored in their library. Their design aim was for good steerability through the curve to maintain good toolface control and fewer course corrections while delivering build rates of 8° to 12° per 100 ft [30 m]. They also sought a significant ROP improvement in the lateral sections. IDEAS tests indicated that cutting structures with flatter profiles provide lower resistance to inclination changes; these were

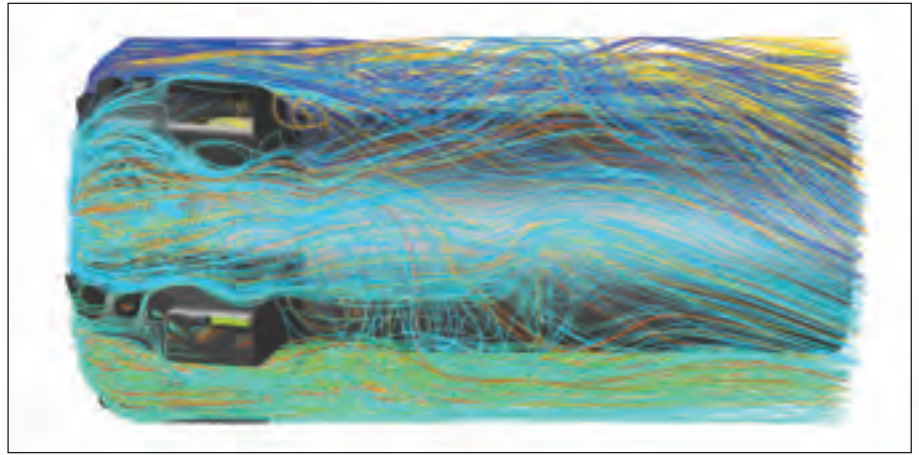
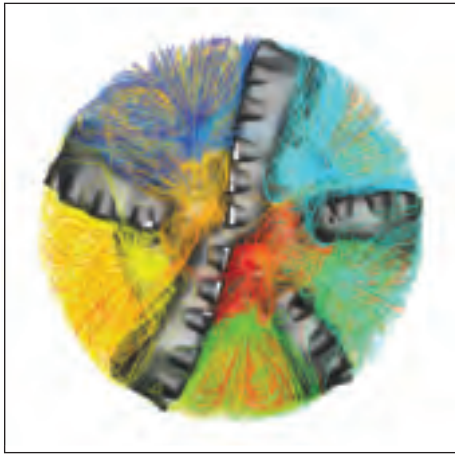
adopted in the design. They also settled on 0.43- to 0.51-in. [11- to 13-mm] diameter cutters because tests showed they had less depth-of-cut (DOC) compared to the larger 0.63- to 0.75-in. [16- to 19-mm] cutters. Greater DOC creates a higher instantaneous torque response, which can cause loss of toolface control and so hinder directional response. Upgrades were also made to the hardfacing materials of the drill bits to better protect the steel from erosive drilling fluid.

Designers concluded that cuttings were not being carried away from the bit because the flow areas between cutter blades to the annulus, known as junk slots, were too narrow. To increase this flow area, engineers could increase the height of the bit blades while reducing their width, but that presented a problem. Current bit matrix designs are limited by the aspect ratio (blade height/blade width) because the tungsten-carbide matrix is relatively brittle and blades that exceed a certain ratio often break upon impact with the formation. Over time, the bits that were formerly made of steel had been replaced by tungsten-carbide bits, which enabled the bits to withstand the erosive forces created by abrasive formation sand and drilling fluids flowing past the bit body. As a consequence, steel PDC bits are rarely considered for use today, except to drill relatively short, low-cost sections.

A solution was found in previous practice. Because shale is characterized by low abrasiveness, steel is sufficiently durable to drill these formations without erosion worries. And, because steel is less brittle than tungsten-carbide matrix, the blades may be extended farther from the bit body with much less potential for breakage due to impact (*left*). By increasing the height and decreasing the width of the blade, the flow area between the bit body and the borehole wall was dramatically increased and drill cuttings were able to pass more freely into the annulus and away from the cutting structure. Fresh rock was exposed and ROP increased.

Using steel, designers could streamline the bit body to make it easier for cuttings to sweep away from the center of the bit toward and into the junk slots. The body diameter of the bit could also be reduced, increasing the distance between the borehole and the bit body at the junk slot.

Fluid dynamics were calculated to simulate the at-bit flow regime. This allowed nozzles to be placed and oriented to minimize recirculation at the bit face, ensuring efficient cuttings removal and elimination of balling and plugging. Blade contour angles were also designed to optimize



^ Fluid flow paths. Once engineers selected the optimal Spear bit design for drilling the Marcellus shale, a computational fluid dynamics program was used to determine how the face of the cutting structure was cleaned and cooled, how effectively the hole was cleaned and how cuttings were evacuated from the bit area and passed up along the annular space. Each color represents the flow path from a specific nozzle. Modeling of fluid flow over the face of the bit (*left*) indicated good total coverage with no dead spots. A side perspective (*right*) indicated flow directed cuttings away from the bit rather than recirculating them around the bit body. A computational fluid dynamics program is used to adjust the nozzle count, size, location and orientation until an optimized design is achieved.

fluid flow at, along and above the bit to minimize steel erosion from drilling mud carrying cuttings (*left*). The resulting hydraulics at the bit face also increased stability and reduced vibrations, which improved ROP and steerability.

This newly developed Spear steel PDC drill-bit, optimized for use in shale, has been used successfully in the Bakken, Barnett, Marcellus and Eagle Ford shale formations of North America. In the Marcellus application, the target ROP goal for drilling the horizontal leg with an 8¼-in. bit was 50 ft/h [15.2 m/h]. The Spear bit achieved ROPs in excess of 65 ft/h [19.8 m/h]. In the Marcellus area, a 6¼-in. Spear bit has consistently drilled the horizontal section in one run with ROPs 10% to 20% faster than the best offset well performance.

Future Perfection

Where once the preoccupation of the oil and gas industry was to find hydrocarbons in economic amounts, today much of its attention is focused on producing remaining and unconventional reserves. That may entail minimizing a surface footprint while drilling horizontally to reach targets kilometers away and hundreds of meters beneath populated or environmentally sensitive areas. Or the challenge may simply be to drill through complex lithology with an ROP that does not destroy project economics.

Regardless of the motive, reaching many of today's potential oil and gas reservoirs requires improved drilling efficiencies to maintain economic viability. Much of what stood in the way of better drilling practices is being eroded by the revolution in gathering, organizing and implementing vast amounts of data quickly. The limitations imposed by human inability to use the immense volumes of data available from many and dissimilar sources have been largely overcome by recent quantum leaps in computing power.

FEA may be one of the most visible of these new tools for improving drilling efficiency, but there are others on the horizon. For example, while the means are in place to accumulate great amounts of data about drilling operations, operators may not always know the best way to leverage the data to improve drilling performance in future wells. One effort currently underway and now enjoying success in field trials addresses this need by using computer neural networks to learn how to best drill formations in a given field. The first step of this process is to train the neural network with offset data, then use a process that includes interval characterization. The system would then present the driller with real-time predictions about WOB and rotation speed that would maximize bit life.

The drilling industry has long discussed automated drilling. Under that general category, drilling operations have seen piecemeal innovations on

the rig floor in the form of iron roughnecks and automated drawworks to perform tasks once done less efficiently by hand. But a truly automated drilling system will be one able to understand and react in real time to the complex, dynamic interactions between bit, BHA, drillstring and the formation. That may be possible soon, but will be of significantly less value if it does not begin with a properly designed bit.

—RvF