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APPLIED DRILLING ENGINEERING

Adam T. Bourgoyne Jr.
Keith K. Millheim
Martin E. Chenevert
F.S. Young Jr.

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Applied Drilling Engineering

Adam T. Bourgoyne Jr.

Professor of Petroleum Engineering
Louisiana State U.

Keith K. Millheim

Manager—Critical Drilling Facility
Amoco Production Co.

Martin E. Chenevert

Senior Lecturer of Petroleum Engineering
U. of Texas

F.S. Young, Jr.

President
Woodway Energy Co.

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Society of Petroleum Engineers
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Dedication

This book is dedicated to the many students who were forced to study from the trial drafts of this work.

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Society of Petroleum Engineers
222 Palisades Creek Drive
Richardson, TX 75080-2040 USA
<http://store.spe.org>
books@spe.org
1.972.952.9393

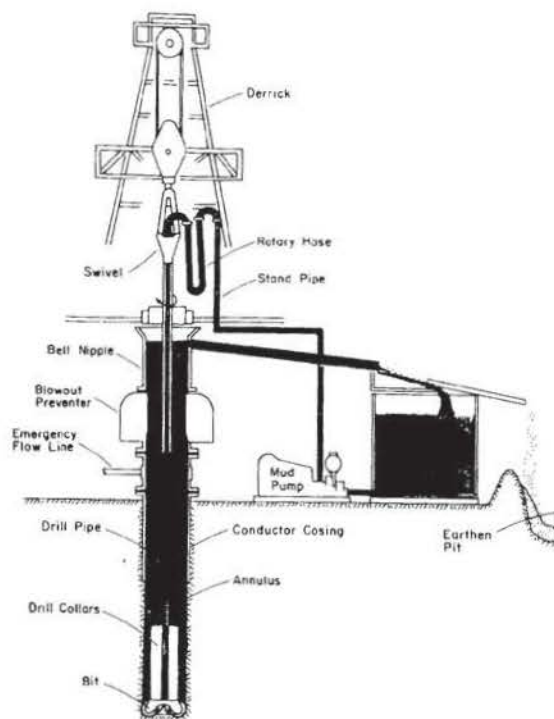


Fig. 1.4 – The rotary drilling process.

1.2 Drilling Rigs

Rotary drilling rigs are used for almost all drilling done today. A sketch illustrating the rotary drilling process is shown in Fig. 1.4. The hole is drilled by rotating a bit to which a downward force is applied. Generally, the bit is turned by rotating the entire drillstring, using a rotary table at the surface, and the downward force is applied to the bit by using sections of heavy thick-walled pipe, called drill collars, in the drillstring above the bit. The cuttings are lifted to the surface by circulating a fluid down the drillstring, through the bit, and up the annular space between the hole and the drillstring. The cuttings are separated from the drilling fluid at the surface.

As shown in Fig. 1.5, rotary drilling rigs can be classified broadly as land rigs or marine rigs. The main design features of land rigs are portability and maximum operating depth. The derrick of the conventional land rig must be built on location. In many cases the derrick is left over the hole after the well is completed. In the early days of drilling, many of these standard derricks were built quite close together as a field was developed. However, because of the high cost of construction, most modern land rigs are built so that the derrick can be moved easily and reused. The various rig components are skid-mounted so that the rig can be moved in units and connected easily. The jackknife, or cantilever, derrick (Fig. 1.6) is assembled on the ground with pins and then raised as a unit using the rig-hoisting equipment. The portable mast (Fig. 1.7), which is suitable for moderate-depth wells, usually is mounted on wheeled trucks or trailers that incorporate the hoisting machinery, engines, and

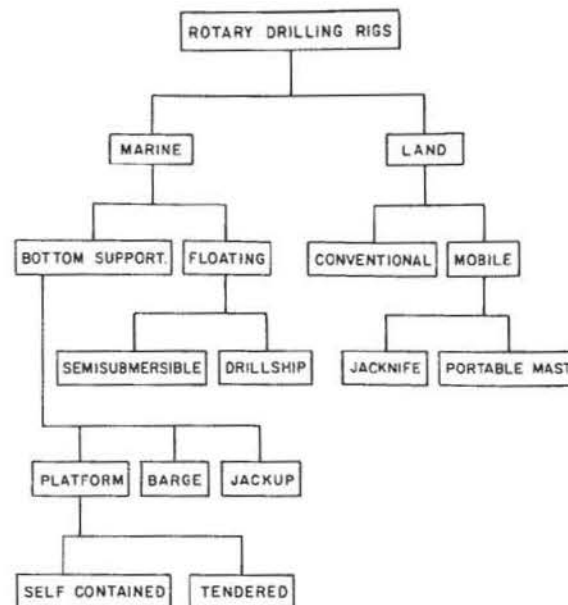


Fig. 1.5 – Classification of rotary drilling rigs.

derrick as a single unit. The telescoped portable mast is raised to the vertical position and then extended to full height by hydraulic pistons on the unit.

The main design features of marine rigs are portability and maximum water depth of operation. Submersible drilling barges generally are used for inland water drilling where wave action is not severe and water depths are less than about 20 ft. The entire rig is assembled on the barge, and the unit is towed to the location and sunk by flooding the barge. Once drilling is completed, the water is pumped from the barge, allowing it to be moved to the next location. After the well is completed, a platform must be built to protect the wellhead and to support the surface production equipment. In some cases, the operating water depth has been extended to about 40 ft by resting the barge on a shell mat built on the seafloor.

Offshore exploratory drilling usually is done using self-contained rigs that can be moved easily. When water depth is less than about 350 ft, bottom-supported rigs can be used. The most common type of bottom-supported mobile rig is the jackup (Fig. 1.8). The jackup rig is towed to location with the legs elevated. On location, the legs are lowered to the bottom and the platform is "jacked up" above the wave action by means of hydraulic jacks.

Semisubmersible rigs that can be flooded similar to an inland barge can drill resting on bottom as well as in a floating position. However, modern semisubmersible rigs (Fig. 1.9) are usually more expensive than jackup rigs and, thus, are used mostly in water depths too great for resting on bottom. At present, most semisubmersible rigs are anchored over the hole. A few semisubmersible rigs employ large engines to position the rig over the hole dynamically. This can extend greatly the maximum operating water depth. Some of these rigs can be used in water

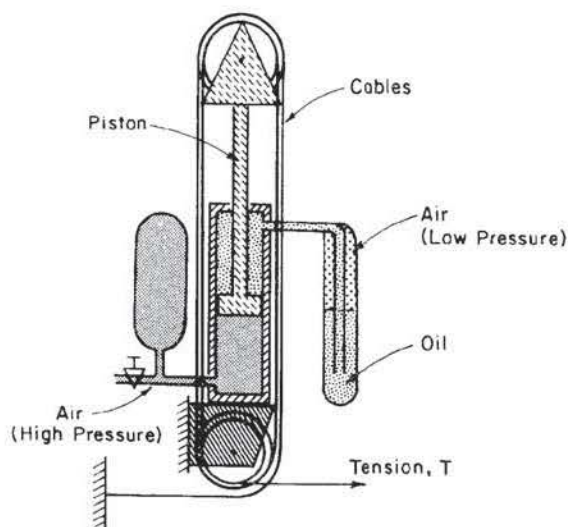


Fig. 1.64—Schematic of a pneumatic tensioning device.

action of the piston and lubricate the packing. A block-and-tackle system allows the use of a shorter piston stroke. Pneumatic tensioning devices often are used on the marine riser, the various guide lines to the subsea wellhead, and on surface motion compensators for the drillstring.

1.10 Drilling Cost Analysis

The main function of the drilling engineer is to recommend drilling procedures that will result in the successful completion of the well as safely and inexpensively as possible. The drilling engineer must make recommendations concerning routine rig operations such as drilling fluid treatment, pump operation, bit selection, and any problems encountered in the drilling operation. In many cases, the use of a drilling cost equation can be useful in making these recommendations. The usual procedure is to break the drilling costs into (1) variable drilling costs and (2) fixed operating expenses that are independent of alternatives being evaluated.

1.10.1 Example Drilling Cost Formula. The most common application of a drilling cost formula is in evaluating the efficiency of a bit run. A large fraction of the time required to complete a well is spent either drilling or making a trip to replace the bit. The total time required to drill a given depth, ΔD , can be expressed as the sum of the total rotating time during the bit run, t_b , the nonrotating time during the bit run, t_c , and trip time, t_t . The drilling cost formula is

$$C_f = \frac{C_b + C_r(t_b + t_c + t_t)}{\Delta D}, \quad \dots \quad (1.16)$$

where C_f is drilled cost per unit depth, C_b is the cost of bit, and C_r is the fixed operating cost of the rig per unit time independent of the alternatives being evaluated.

Since this drilling cost function ignores risk fac-

tors, the results of the cost analysis sometimes must be tempered with engineering judgment. Reducing the cost of a bit run will not necessarily result in lower well costs if the risk of encountering drilling problems such as stuck pipe, hole deviation, hole washout, etc., is increased greatly.

Example 1.5. A recommended bit program is being prepared for a new well using bit performance records from nearby wells. Drilling performance records for three bits are shown for a thick limestone formation at 9,000 ft. Determine which bit gives the lowest drilling cost if the operating cost of the rig is \$400/hr, the trip time is 7 hours, and connection time is 1 minute per connection. Assume that each of the bits was operated at near the minimum cost per foot attainable for that bit.

Bit	Bit Cost (\$)	Rotating Time (hours)	Connection Time (hours)	Mean Penetration Rate (ft/hr)
A	800	14.8	0.1	13.8
B	4,900	57.7	0.4	12.6
C	4,500	95.8	0.5	10.2

Solution. The cost per foot drilled for each bit type can be computed using Eq. 1.16. For Bit A, the cost per foot is

$$C_f = \frac{800 + 400(14.8 + 0.1 + 7)}{13.8(14.8)} = \$46.81/\text{ft.}$$

Similarly, for Bit B,

$$C_f = \frac{4,900 + 400(57.7 + 0.4 + 7)}{12.6(57.7)} = \$42.56/\text{ft.}$$

Finally, for Bit C,

$$C_f = \frac{4,500 + 400(95.8 + 0.5 + 7)}{10.2(95.8)} = \$46.89/\text{ft.}$$

The lowest drilling cost was obtained using Bit B.

1.10.2 Drilling Cost Predictions. The drilling engineer frequently is called upon to predict the cost of a well at a given location. These predictions are required so that sound economic decisions can be made. In some cases, such as the evaluation of a given tract of land available for lease, only an approximate cost estimate is required. In other cases, such as in a proposal for drilling a new well, a more detailed cost estimate may be required.

Drilling cost depends primarily on well location and well depth. The location of the well will govern the cost of preparing the wellsite, moving the rig to the location, and the daily operating cost of the drilling operation. For example, an operator may find from experience that operating a rig on a given lease offshore Louisiana requires expenditures that will average about \$30,000/day. Included in this daily operating cost are such things as rig rentals, crew boat rentals, work boat rentals, helicopter

of 800 bbl of 12-lbm/gal mud to 14 lbm/gal. One gallon of water will be added with each 100-lbm sack of API barite to prevent excessive thickening of the mud. A final mud volume of 800 bbl is desired. Compute the volume of old mud that should be discarded and the mass of API barite to be added.

Solution. The water requirement for barite, V_{wB} , is 0.01 gal/lbm. The initial volume of 12-lbm/gal mud needed can be computed using Eq. 2.19. For a final volume of 800 bbl, V_1 is given by

$$V_1 = 800 \left\{ \frac{35.0 \left[\frac{1 + 8.33(0.01)}{1 + 35.0(0.01)} \right] - 14.0}{35.0 \left[\frac{1 + 8.33(0.01)}{1 + 35.0(0.01)} \right] - 12.0} \right\}$$

$$= 700.53 \text{ bbl.}$$

Thus, 99.47 bbl of mud should be discarded before adding any API barite. Using Eq. 2.20, the mass of API barite needed is given by

$$m_B = \frac{35.0}{1 + 35.0(0.01)} (800 - 700.53)(42)$$

$$= 108,312 \text{ lbm.}$$

The volume of water to be added with the barite is

$$0.01 m_B = 1,083 \text{ gal or } 25.79 \text{ bbl.}$$

Considerable savings can be achieved in mud treatment costs for a weighted mud system if (1) the total mud volume is held as low as possible and (2) the initial conversion from an unweighted system to a weighted system is done with the low-specific-gravity solids at the minimum possible concentration. The reduction in solids concentration by dilution is much less expensive before the conversion is made because the mud discarded during dilution does not contain any API barite. When mud dilution just precedes weighting operations, the proper volume of old mud, V_1 , dilution water, V_w , and mass of weight material, m_B , that should be combined to obtain a desired volume of new mud, V_2 , can be determined using the ideal mixing calculations. For ideal mixing, the total new volume is given by

$$V_2 = V_1 + V_w + \frac{m_B}{\rho_B}$$

Similarly, a mass balance on the mixing procedure requires

$$\rho_2 V_2 = \rho_1 V_1 + \rho_w V_w + m_B.$$

A third equation can be obtained by performing a volume balance on the low-specific-gravity solids. The volume of low-specific-gravity solids can be expressed in terms of the present volume fraction, f_{c1} , and the desired new volume fraction, f_{c2} :

$$f_{c2} V_2 = f_{c1} V_1$$

Solving these three equations simultaneously yields

$$V_1 = V_2 \frac{f_{c2}}{f_{c1}}, \dots \dots \dots (2.21)$$

$$V_w = \frac{(\rho_B - \rho_2)V_2 - (\rho_B - \rho_1)V_1}{(\rho_B - \rho_w)}, \dots \dots \dots (2.22)$$

and

$$m_B = (V_2 - V_1 - V_w) \rho_B. \dots \dots \dots (2.23)$$

Example 2.18. After cementing casing in the well, it is desirable to increase the density of the 9.5-lbm/gal mud to 14 lbm/gal before resuming drilling operations. It also is desired to reduce the volume fraction of low-specific-gravity solids from 0.05 to 0.03 by dilution with water. The present mud volume is 1,000 bbl, but a final mud volume of 800 bbl is considered adequate. Compute the amount of original mud that should be discarded and the amount of water and API barite that should be added.

Solution. The initial volume of 9.5-lbm/gal mud needed can be computed using Eq. 2.21. For a final volume of 800 bbl, V_1 is given by

$$V_1 = 800 \frac{0.03}{0.05} = 480 \text{ bbl.}$$

Thus, 520 bbl of the initial 1,000 bbl should be discarded before adding any water or barium sulfate. Using Eq. 2.22, the volume of water needed is

$$V_w = \frac{(35.0 - 14.0) 800 - (35.0 - 9.5) 480}{(35.0 - 8.33)}$$

$$= 171 \text{ bbl.}$$

Using Eq. 2.23, the mass of API barite needed is given by

$$m_B = (800 - 480 - 171)(42)(35.0) = 219,000 \text{ lbm.}$$

2.3.13 Solids Control for Weighted Mud. The addition of solids for increasing density lowers the amount of inert formation solids that can be tolerated. The ideal composition of a weighted clay/water mud is (1) water, (2) active clay, and (3) inert weight material. Thus, every possible effort should be made to remove the undesirable low-gravity solids by screening before their particle size is reduced within the size range of the API barite particles. Hydrocyclones cannot be used alone on weighted systems because their cut point falls in the particle-size range of the API barite as shown in Fig. 2.26. However, they sometimes are used in conjunction with a shaker screen to increase the flow rate capacity of the solids removal equipment. A series arrangement of a hydrocyclone and a shaker screen is called a *mud cleaner*. It is suited best for muds of moderate density (below 15 lbm/gal). The fine solids that pass through the screen can be handled by dilution and deflocculation.

At higher densities, the mud cleaners are much less efficient. Much of the coarse solids in the mud remain in the liquid stream exiting the top of the unit and, thus, bypass the screen. Also, dilution requires

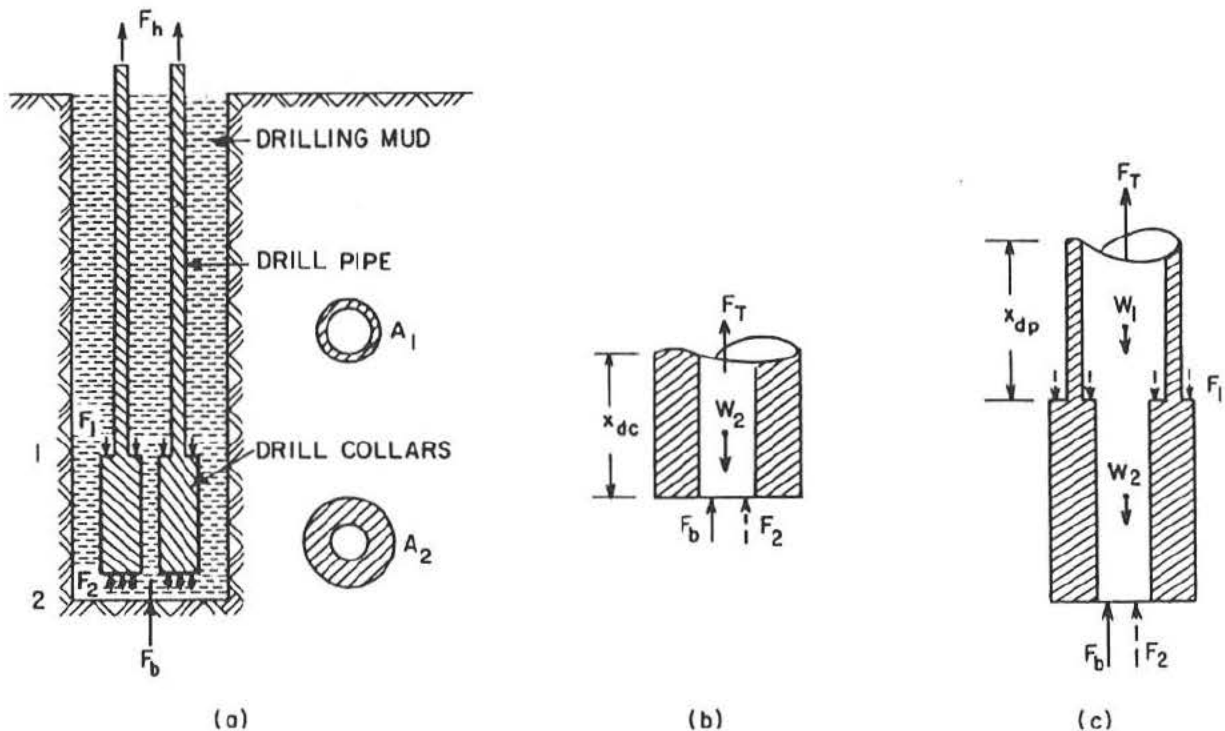


Fig. 4.10—Effect of hydrostatic pressure on axial forces in drillstring: (a) schematic of drillstring, (b) free body diagram for drill collars, and (c) free body diagram for drillpipe.

4.5.1 Determination of Axial Stress

In Example 4.8, only the net effect of hydrostatic pressure on the pipe string was required. However, in some cases it may be necessary to compute the axial stress at a given point in the pipe string. The axial stress is the axial tension in the pipe string divided by the cross-sectional area of steel. When axial stress must be determined, the effective points of application of the hydrostatic pressure must be considered and Archimedes' relation cannot be used.

Consider the idealized schematic of a drillstring suspended in a well (Fig. 4.10a). The lower portion of the drillstring is composed of drill collars, while the upper portion is composed of drillpipe. To apply a downward force, F_b , on the bit, the drillstring is lowered until a portion of the weight of the pipe string is supported by the bottom of the hole. The cross-sectional area of the drill collars, A_2 , is much greater than the cross-sectional area of the drillpipe, A_1 . Note that hydrostatic pressure is applied to the bottom of the drill collars against a cross-sectional area, A_2 , and at the top of the drill collars against the cross section, $A_2 - A_1$. To determine the axial tension F_T in the drill collars, consider a free body diagram of the lower portion of the drillstring (Fig. 4.10b). For the system to be in equilibrium,

$$F_T = W_2 - F_2 - F_b = w_{dc}x_{dc} - p_2A_2 - F_b, \quad (4.24a)$$

where

w_{dc} = weight per unit length of drill collars in air,
 x_{dc} = distance from the bottom of the drill collars to the point of interest,

p_2 = hydrostatic pressure at Point 2, and
 F_b = force applied to the bit.

To determine the axial tension in the drillpipe, consider a free-body diagram of the upper portion of the drillstring (Fig. 4.10c). As before, system equilibrium requires that

$$\begin{aligned} F_T &= W_1 + W_2 + F_1 - F_2 - F_b \\ F_T &= w_{dp}x_{dp} + W_2 + p_1(A_2 - A_1) \\ &\quad - p_2A_2 - F_b, \quad \dots \dots \dots (4.24b) \end{aligned}$$

where

w_{dp} = weight per foot of drillpipe in air,
 x_{dp} = distance from the bottom of the drillpipe (top of drill collars) to the point of interest, and
 p_1 = hydrostatic pressure at Point 1.

Axial stress is obtained by dividing the axial tension by the cross-sectional area of steel.

Example 4.9. Prepare a graph of axial tension vs. depth for the drillstring described in Example 4.8. Also develop expressions for determining axial stress in the drillstring.

Solution. The hydrostatic pressure p at the top of the drill collars is given by

$$p_1 = 0.052(15)(10,000) = 7,800 \text{ psig.}$$

Chapter 5

Rotary Drilling Bits

The purpose of this chapter is to introduce the student to the selection and operation of drilling bits. Included in the chapter are discussions of (1) various bit types available, (2) criteria for selecting the best bit for a given situation, (3) standard methods for evaluating dull bits, (4) factors affecting bit wear and drilling speed, and (5) optimization of bit weight and rotary speed.

The process of drilling a hole in the ground requires the use of drilling bits. Indeed, the bit is the most basic tool used by the drilling engineer, and the selection of the best bit and bit operating conditions is one of the most basic problems that he faces. An extremely large variety of bits are manufactured for different situations encountered during rotary drilling operations. It is important for the drilling engineer to learn the fundamentals of bit design so he can understand fully the differences among the various bits available.

5.1 Bit Types Available

Rotary drilling bits usually are classified according to their design as either *drag bits* or *rolling cutter bits*. All drag bits consist of fixed cutter blades that are integral with the body of the bit and rotate as a unit with the drillstring. The use of this type of bit dates back to the introduction of the rotary drilling process in the 19th century. Rolling cutter bits have two or more cones containing the cutting elements, which rotate about the axis of the cone as the bit is rotated at the bottom of the hole. A two-cone rolling cutter bit was introduced in 1909.

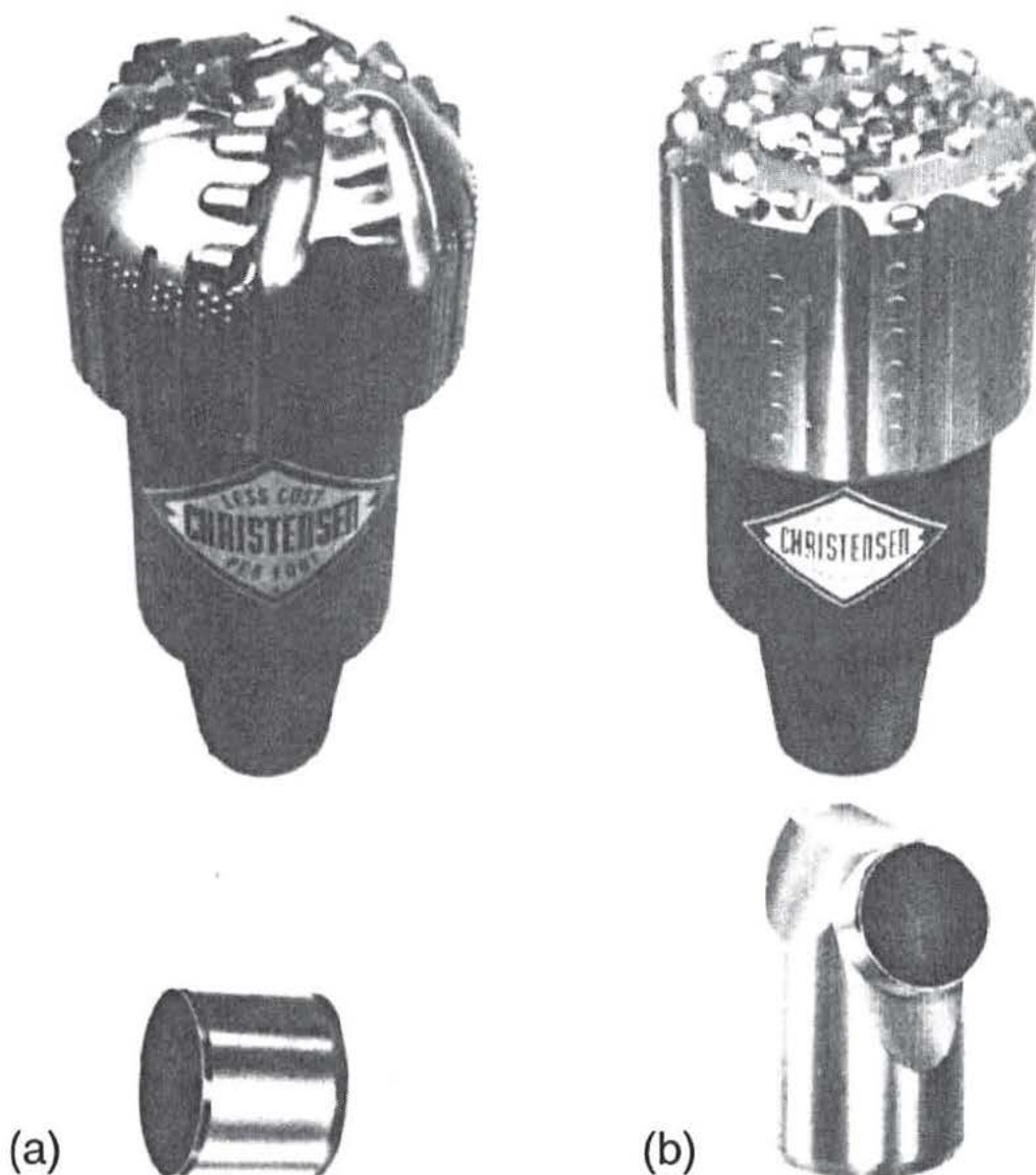
5.1.1 Drag Bits

The design features of the drag bit include the number and shape of the cutting blades or stones, the size and location of the water courses, and the metallurgy of the bit and cutting elements. Drag bits drill by physically plowing cuttings from the bottom of the borehole much like a farmer's plow cuts a furrow in the soil. This type

of bit includes bits with steel cutters (Fig. 5.1), diamond bits (Fig. 5.2), and polycrystalline diamond (PCD) bits (Fig. 5.3). An advantage of drag bits over rolling cutting bits is that they do not have any rolling parts, which require strong, clean bearing surfaces. This is especially important in the small hole sizes, where space is not available for designing strength into both the bit cutter elements and the bearings needed for a rolling cutter. Also, since drag bits can be made from one solid piece of steel, there is less chance of bit breakage, which would leave *junk* in the bottom of the hole. Removing junk from a previous bit can lead to additional trips to the bottom and thus loss of considerable rig time.

Drag bits with steel cutter elements such as a fishtail bit perform best relative to other bit types in uniformly soft, unconsolidated formations. As the formations become harder and more abrasive, the rate of bit wear increases rapidly and the drilling rate decreases rapidly. This problem can be reduced by changing the shape of the cutter element and reducing the angle at which it intersects the bottom of the hole. Also, in soft formations that tend to be "gummy," the cuttings may stick to the blades of a drag bit and reduce their effectiveness. This problem can be reduced by placing a jet so that drilling fluid impinges on the upper surface of the blade. Because of the problems of rapid dulling in harder rocks and bit cleaning in gummy formations, drag bits with steel cutting elements largely have been displaced by other bit types in almost all areas.

Diamond bits perform best relative to other bit types in nonbrittle formations that have a plastic mode of failure for the stress conditions present at the bottom of the hole. The face or crown of the bit consists of many diamonds set in a tungsten carbide matrix. Under proper bit operation only the diamonds contact the hole bottom, leaving a small clearance between the matrix and the hole bottom. Fluid courses are provided in the matrix to direct the flow of drilling fluid over the face of the bit. These



Courtesy of Norton Christensen

Fig. 5.3—Example polycrystalline diamond cutter bits.

polycrystalline diamond about $\frac{1}{64}$ -in. thick that is bonded to a cemented tungsten carbide substrate in a high-pressure/high-temperature process. It contains many small diamond crystals bonded together. The cleavage planes of the diamond crystals have a random orientation that prevents any shock-induced breakage of an individual diamond crystal from easily propagating through the entire cutter. As shown in Fig. 5.3, the sintered polycrystalline diamond compact is bonded either to a tungsten carbide bit-body matrix or to a tungsten carbide stud that is mounted in a steel bit body.

The PCD bits are still evolving rapidly. They perform best in soft, firm, and medium-hard, nonabrasive formations that are not "gummy." Good results have been reported with PCD bits in drilling uniform sections of carbonates or evaporites that are not broken up with hard shale stringers. Successful use of these bits also has been

accomplished in sandstone, siltstone, and shale, although bit balling is a serious problem in very soft, gummy formations, and rapid cutter abrasion and breakage are serious problems in hard, abrasive formations. As in the case of the older, steel cutter drag bits, bit hydraulics can play an important role in reducing bit balling.

The bit shape or crown profile is also an important design feature of PCD bits. In addition to the double-cone profiles (Fig. 5.4C) used for diamond bits, single-cone profiles of various tapers and flat-bottom profiles are used for PCD bits. The hydraulic cleaning action is usually achieved primarily by using jets for steel-body PCD bits and by using water courses for matrix-body PCD bits.

Other important design features of a PCD bit include the size, shape, and number of cutters used and the angle

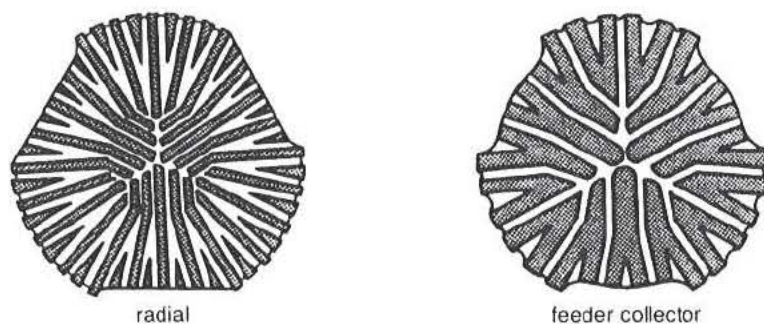
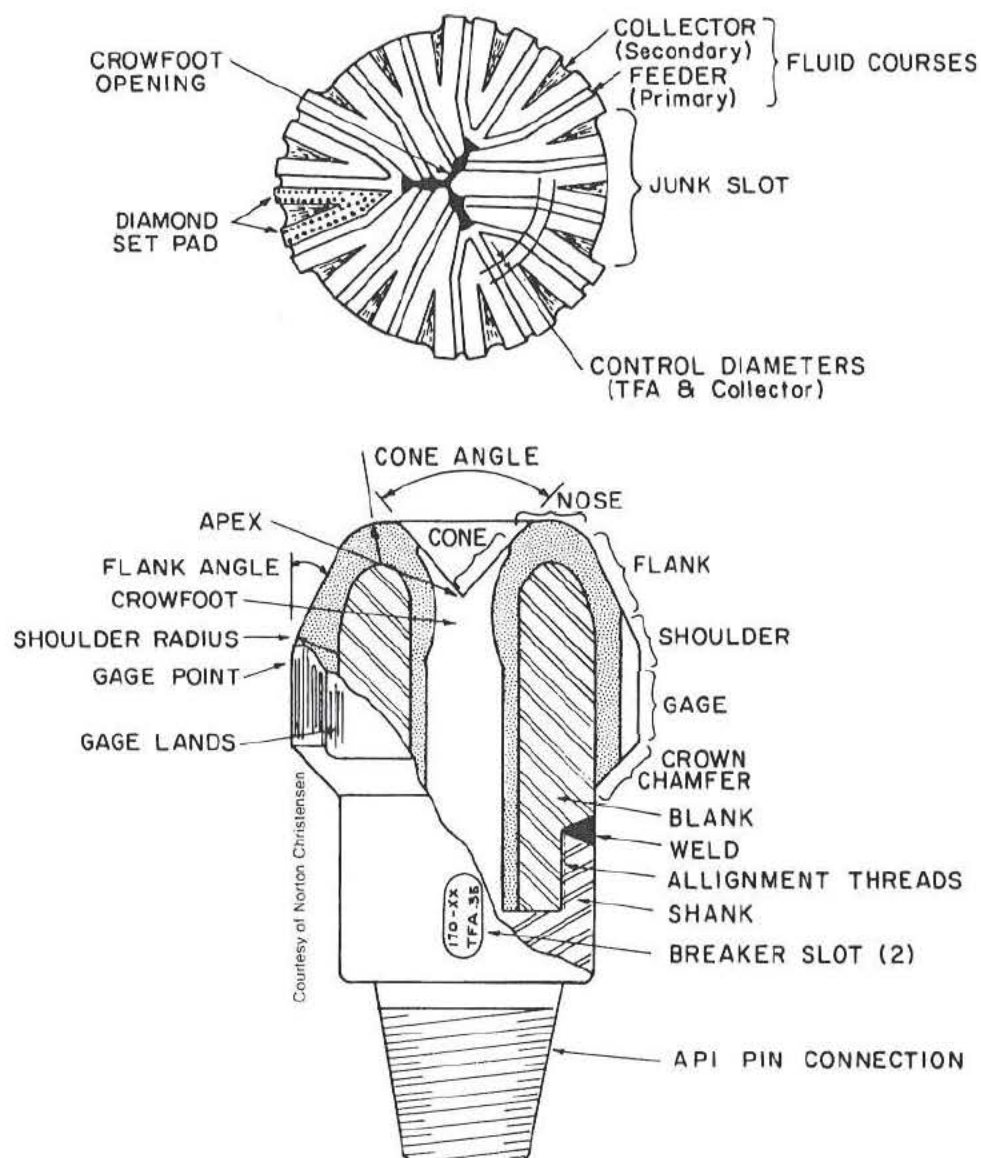


Fig. 5.4B—Diamond cutter drag bit—example profiles and features.

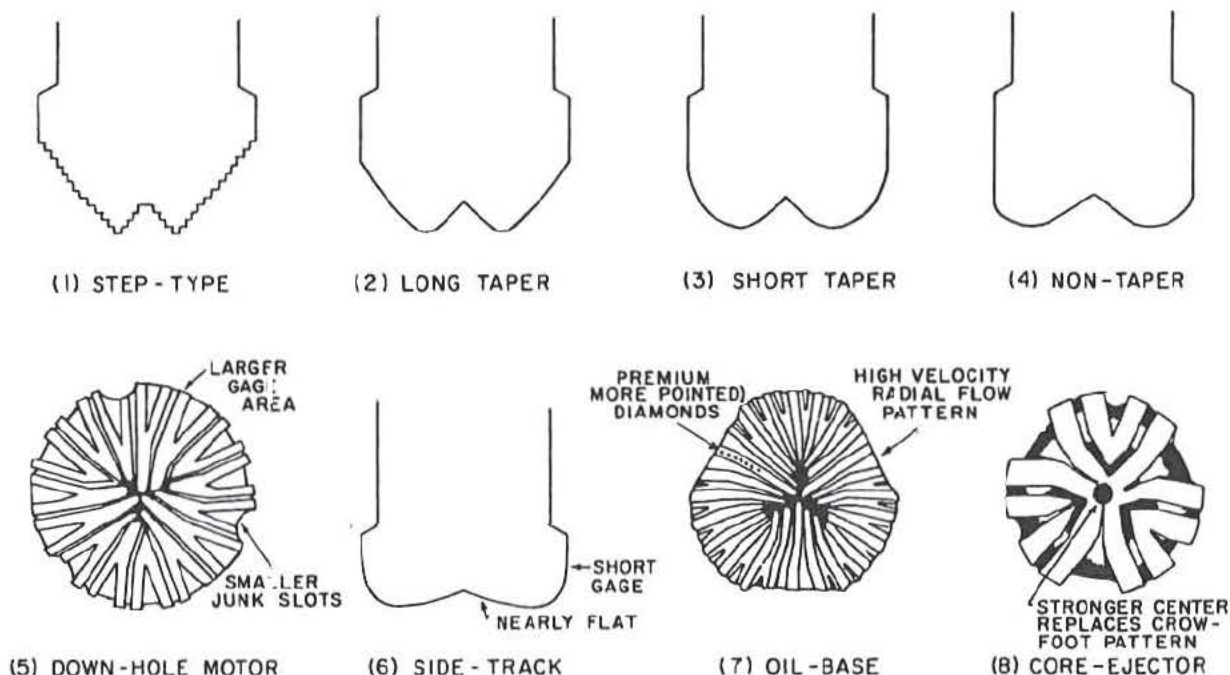


Fig. 5.4C—Diamond cutter drag bit—radial and feeder collectors.

of attack between the cutter and the surface of the exposed formation. Cutter orientation is defined in terms of back rake, side rake, and chip clearance or cutter exposure (Fig. 5.5).¹

At present, a negative back-rake angle of 20° is standard on many steel-body PCD bits. However, smaller back-rake angles, which are better-suited for soft formations, are also available, especially in the matrix-body PCD bits. The side-rake assists in pushing the cuttings formed to the side of the hole, much like the action of a plow. The exposure of the cutter provides room for the cutting to peel off the hole bottom without impacting against the bit body and packing in front of the cutter.

Cutter orientation must be properly matched to the hardness of the formation being drilled. In soft, nonabrasive formations, where cutter wear is very slow, the orientation can be set to emphasize aggressive cutting. The high temperatures and wear rates caused by harder, more abrasive formations require a less-aggressive cutter orientation to prevent an excessive wear rate. The cutter orientation also depends on the expected cutter velocity, which in turn depends on the distance of the cutter location from the center of the hole.

5.1.3 Rolling Cutter Bits

The three-cone rolling cutter bit is by far the most common bit type currently used in rotary drilling operations. This general bit type is available with a large variety of tooth design and bearing types and, thus, is suited for a wide variety of formation characteristics. Fig. 5.6 is an example of a rolling cutter bit with the various parts labeled.² The three cones rotate about their axis as the bit is rotated on bottom.

The largest limitation a bit design engineer faces is that the bit must fit inside the borehole. The designer, thus, is required to make maximum use of a very limited amount of space. The size of every critical part can be increased

only at the expense of another critical part. This is especially true for the smaller bit sizes. Whereas most machines are designed to last for years, bits generally last at best only a few days.

The drilling action of a rolling cutter bit depends to some extent on the *offset* of the cones. As shown in Fig. 5.7, the offset of the bit is a measure of how much the cones are moved so that their axes do not intersect at a common point of the centerline of the hole. Offsetting causes the cone to stop rotating periodically as the bit is turned and scrape the hole bottom much like a drag bit. This action tends to increase drilling speed in most formation types. However, it also promotes faster tooth wear in abrasive formations. Cone offset is sometimes expressed as the angle the cone axis would have to be rotated to make it pass through the centerline of the hole. Cone offset angle varies from about 4° for bits used in soft formations to zero for bits used in extremely hard formations.

The shape of the bit teeth also has a large effect on the drilling action of a rolling cutter bit. Long, widely spaced, steel teeth are used for drilling soft formations. The long teeth easily penetrate the soft rock, and the scraping/twisting action provided by alternate rotation and plowing action of the offset cone removes the material penetrated. The action of this type bit often is compared with pushing a shovel into the ground and then leaning back on the handle to remove a large piece of earth. The wide spacing of the teeth on the cone promotes bit cleaning. Teeth cleaning action is provided by the intermeshing of teeth on different cones and by fluid jets between each of the three cones. As the rock type gets harder, the tooth length and cone offset must be reduced to prevent tooth breakage. The drilling action of a bit with zero cone offset is essentially a crushing action. The smaller teeth also allow more room for the construction of stronger bearings.

The metallurgy requirements of the bit teeth also depend on the formation characteristics. The two primary types used are (1) *milled tooth cutters* and (2) *tungsten carbide insert cutters*. The milled tooth cutters are manufactured by milling the teeth out of a steel cone, while the tungsten carbide insert bits are manufactured by pressing a tungsten carbide cylinder into accurately machined holes in the cone. The milled tooth bits designed for soft formations usually are faced with a wear-resistant material, such as tungsten carbide, on one side of the tooth. As shown in Fig. 5.8, the application of hard facing on only one side of the tooth allows more rapid wear on one side of the tooth than the other, and the tooth stays relatively sharp.

The milled tooth bits designed to drill harder formations are usually case hardened by special processing and heat treating the cutter during manufacturing. As shown in Fig. 5.8, this case-hardened steel should wear by chipping and tend to keep the bit tooth sharp.

The tungsten carbide teeth designed for drilling soft formations are long and have a chisel-shaped end. The inserts used in bits for hard formations are short and have a hemispherical end. These bits are sometimes called *button bits*. Examples of various insert bit tooth designs are shown in Fig. 5.9.

Considerable thought has gone into the position of the teeth on the cones of a rolling cutter bit. The inner rows of teeth are positioned on different cones so that they intermesh. This intermeshing (1) allows more room for a stronger bit design, (2) provides a self-cleaning action as the bit turns, and (3) allows maximum coverage of the hole bottom for a given number of teeth. The bottomhole coverage of most bits is about 70%. The outer row of teeth on each cone do not intermesh. This row of teeth, called the *heel teeth*, has by far the hardest job. Due to the circular geometry, more rock must be removed from the outermost annular ring of the hole bottom, and this rock is more difficult to remove because it tends to remain attached to the borehole wall.

Some of the heel teeth often are designed with *interruptions* or *indentions* as shown in Fig. 5.6. These interruptions allow the heel teeth to generate a pattern on bottom having one-half the spacing of the cutter teeth. Thus, the cuttings are smaller than the space between the teeth and do not wedge between them readily. Because the heel teeth have a more difficult job, they may wear excessively, causing the bit to drill an out-of-gauge hole. This causes a gross misalignment of the load on the bearings and premature bit failure. Premature failure of the next bit is also likely if the hole remains undersized. Most bit manufacturers offer more than one heel tooth design with a given bit type so the drilling engineer may obtain the amount of gauge protection needed.

The common bearing assemblies used for rolling cutter bits are shown in Fig. 5.10. The standard or most inexpensive bearing assembly shown in Fig. 5.10a consists of (1) a roller-type outer bearing, (2) a ball-type intermediate bearing, and (3) a friction-type nose bearing. The roller-type outer bearing is the most heavily loaded member and usually tends to wear out first. The race that the roller bearing rolls over tends to spall and wear on the bottom side where the weight applied to the bit is transmitted from the pin to the cone. The intermediate ball bearings carry primarily axial or thrust loads on the

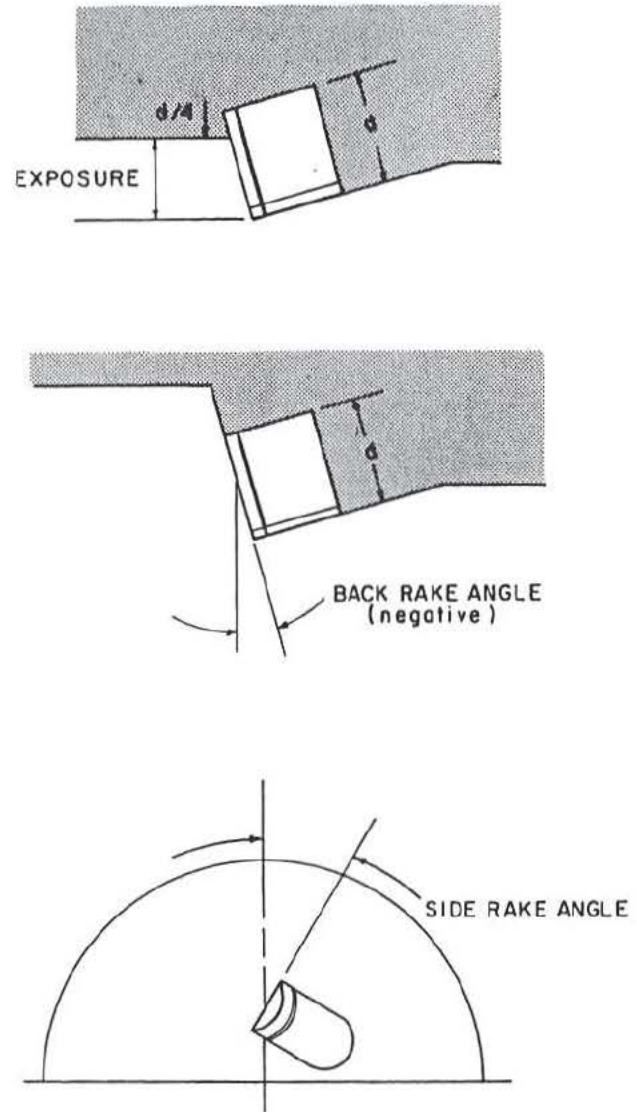


Fig. 5.5—Cutter orientation expressed in terms of exposure, back rake, and side rakes.

cones. They also serve to hold the cone in place on the bit. The nose bearings are designed to carry a portion of the axial or thrust loads after the ball bearings begin to wear. The nose bearing is a friction-type bearing in most bit sizes, but in the larger bit sizes another roller bearing is used. In the standard bearing design, all bearings are lubricated by the drilling fluid. When a gas is used as the drilling fluid, a modified bit is available with passageways permitting a portion of the gas to flow through the bearing assembly (Fig. 5.10b).

The intermediate-cost bearing assembly used in rolling cutter bits is the *sealed bearing* assembly. A cross section of a sealed bearing bit is shown in Fig. 5.10c. In this type bit, the bearings are maintained in a grease environment by grease seals, a grease reservoir, and a compensator plug that allows the grease pressure to be maintained equal to the hydrostatic fluid pressure at the bottom of the hole. While the grease seals require some space and, thus, a reduction in bearing capacity, the elimination of abrasive material from the bearings usually more than compensates for this disadvantage. As the

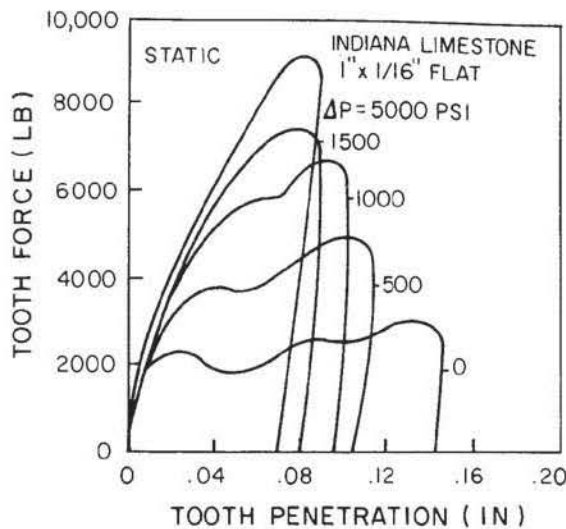
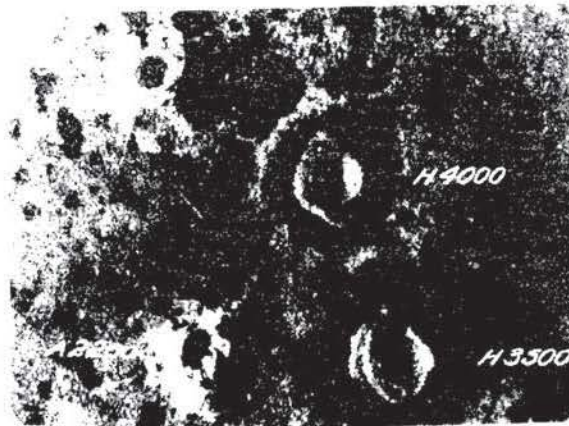


Fig. 5.18—Typical force displacement curves as a function of differential mud pressure,⁷ ($\Delta p = p_{bh} - p_f$).

predicted by the Mohr failure criteria. The force at which fracturing begins beneath the tooth is called the *threshold force*. As the force on the tooth increases above the threshold value, subsequent fracturing occurs in the region above the initial fracture, forming a zone of broken rock (D). At low differential pressure, the cuttings formed in the zone of broken rock are ejected easily from the crater (E). The bit tooth then moves forward until it reaches the bottom of the crater, and the process may be repeated (F,G). At high differential pressures, the downward pressure and frictional forces between the rock fragments prevent ejection of the fragments (E'). As the force on the tooth is increased, displacement takes place along fracture planes parallel to the initial fracture (F',G'). This gives the appearance of plastic deformation, and craters formed in this manner are called *pseudoplastic* craters. Typical force displacement curves for increasing values of differential pressure are shown in Fig. 5.18.

Examples of craters formed at both high and low values of differential pressure² are shown in Fig. 5.19. A 5-mm tungsten carbide penetrator was loaded to produce failure in a sample of Rush Springs sandstone. The sample was coated with plastic to simulate the buildup of a mudcake that would prevent the wellbore fluid from entering the pore space of the rock and equalizing the pressure differential. The two craters on the left were made with the formation at atmospheric pressure and with bit tooth loads of 1,600 and 2,200 lbf. The chips formed were removed easily. The two craters on the right were made at a pressure differential of 5,000 psi and bit tooth loads of 3,500 and 4,000 lbf. The material extruded from the craters that is characteristic of pseudoplastic crater formation was not removed easily, although it was weaker than the undisturbed formation.

High-speed movies⁸ of full-scale bits drilling at atmospheric conditions with air as the circulating fluid have verified that the mechanisms of failure for rolling cutter bits with little or no offset is not too different from that observed in single bit-tooth impact experiments. This is shown in the sequence of photographs in Figs.



Courtesy of Hughes Tool Co.

Fig. 5.19—Example of craters formed in single-tooth impact apparatus.

5.20a and 5.20b. Starting in Photograph 1, a tooth starts to apply pressure to the rock as the cone rolls forward. In Photograph 4, the threshold force has been transmitted to the rock and fracture is initiated. In Photograph 5, which is shown in more detail in Fig. 5.20b, ejection of the rock fragments from the crater proceeds in an explosive manner. Chips continue to be ejected in Photographs 6 through 9 as the tooth sinks further into the rock. Finally, in Photograph 10, particle discharge diminishes and the next tooth begins to apply force to the rock.

The drilling action of rolling cutter bits designed with a large offset for drilling soft, plastic formations is considerably more complex than the simple crushing action that results when no offset is used. Since each cone alternately rolls and drags, considerable wedging and twisting action is present. Shown in Fig. 5.21 is a comparison of the bottomhole patterns generated by a bit with no offset and a bit with considerable offset. The alternate rolling and dragging action of the high offset cones is evident from the bottomhole pattern of the bit teeth.

5.3 Bit Selection and Evaluation

Unfortunately, the selection of the best available bit for the job, like the selection of the best drilling fluid or drilling cement composition, can be determined only by trial and error. The most valid criterion for comparing the performance of various bits is the drilling cost per unit interval drilled. The cost-per-foot formula presented in Chap. 1 (Eq. 1.16) can be used for this purpose. Since no amount of arithmetic allows us to drill the same section of hole more than once, comparisons must be made between succeeding bits in a given well or between bits used to drill the same formations in different wells. The formations drilled with a given bit on a previous nearby well can be correlated to the well in progress using well logs and mud logging records.

The initial selection of bit type in a wildcat area can be made on the basis of what is known about the formation characteristics and drilling cost in an area. The terms