



ROTARY DRILLING

THE BIT

Fourth Edition

UNIT I • LESSON 2



The Bit

Unit I, Lesson 2
Fourth Edition



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THE BIT

Besides rotating the bit, the rig crew also has to circulate drilling fluid through it to lift the drilled pieces of rock (the cuttings) out of the hole (fig. 2). Removing the cuttings keeps them from interfering with the bit's cutters. Cutters are the part of the bit that actually cuts, or drills, the rocks. Bit cutters can be steel teeth, very hard metal buttons, diamonds, or specially designed components called compacts (fig. 3).

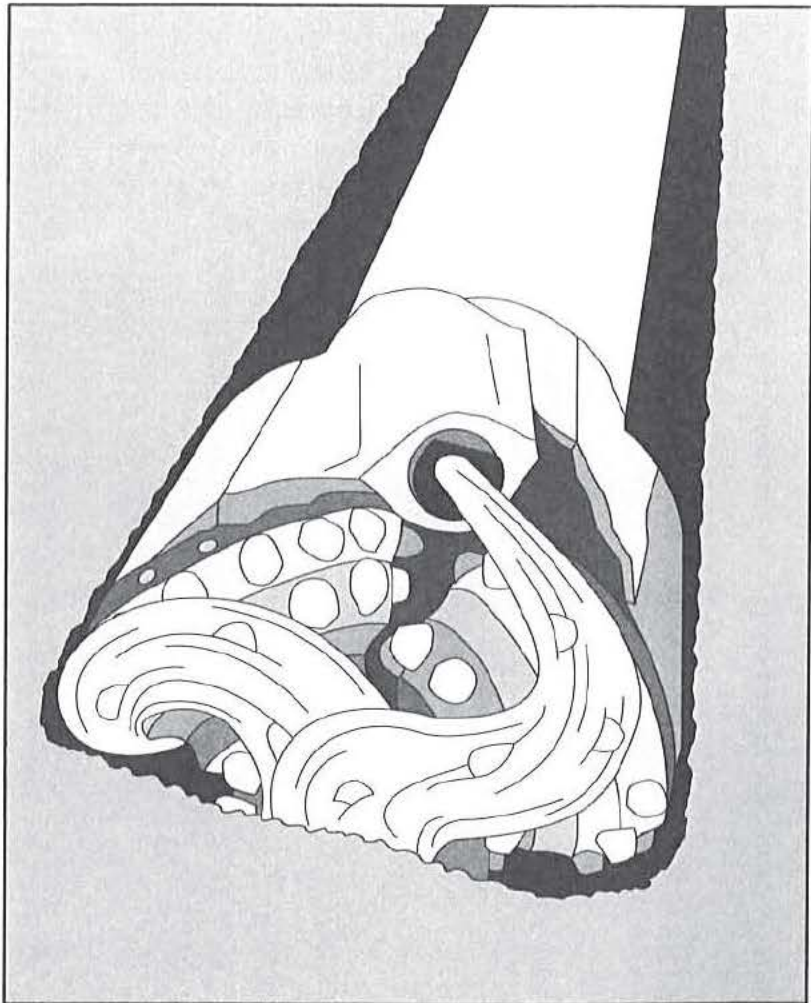


Figure 2. Circulating drilling fluid lifts cuttings.

mentioned earlier, it occurs when the pattern made by the bit on the bottom of the hole matches the pattern of the teeth. The bit then meshes like a gear with the formation and drills very little. Tracking can happen when the formation is plastic—that is, it bends under stress without breaking; the opposite of brittle. Using a bit designed for a softer formation may remedy this problem.

When the cutters drag on the formation, they heat up. The drilling fluid then cools them. When this cycle occurs many times, *heat checking* can result (fig. 45). Checking means to develop small cracks.

Gauge rounding, when the gauge cutters wear down in a rounded fashion, may be serious (fig. 46). If the bit can still drill a full-gauge hole, however, the wear is not a problem. Minor gauge rounding can happen when drilling an abrasive formation at too high a rotary speed or reaming an undergauge hole. If, however, the gauge cutters are so worn away that the bit drills an undergauge hole, a problem exists. The next bit will have to ream the hole to the appropriate size, which may damage the new bit and waste time.

In extreme cases of gauge wear, the shirrtail and gauge area of the bit are so worn away that the bearings fall out of the bit. Extreme gauge wear can occur when using a bit that is not strong enough for the type of formation being drilled, running a bit for too long, or using a rotary speed that is too fast for the specific bit.

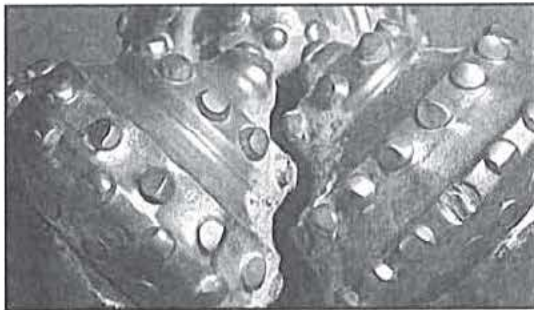


Figure 44. Tracking wear

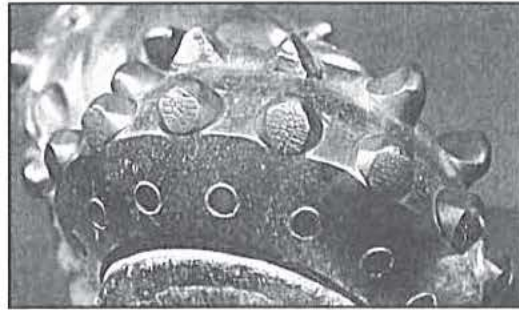


Figure 45. Heat checking

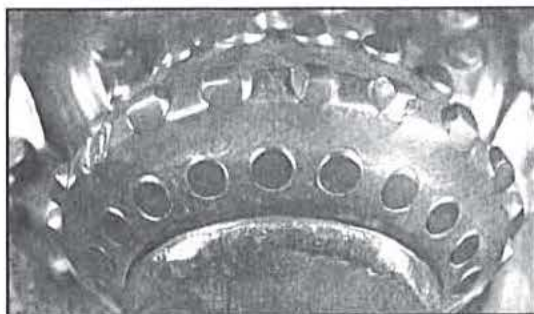


Figure 46. Gauge rounding

To summarize—

Types of cutter wear—

- Broken inserts
 - Gauge row breakage
 - Broken teeth
 - Chipped cutter
 - Lost inserts
 - Bradding
 - Heat checking
 - Gauge wear
-

Bearing Wear

Bearing wear and failure often make it necessary to stop drilling and replace the bit. Spalling and galling used to be the biggest problems with bearings. The advent of sealed bearings has substantially reduced such wear, however. Even so, better design has not eliminated bearing wear altogether.

The *outer bearings* (the roller bearing or journal bearing under the gauge cutters) can fail for any of several reasons. Excessive rotation time coupled with heavy weight can wear them out. Abrasive materials in the drilling fluid can damage nonsealed bearings, as can corrosion caused by sulfur in the drilling fluid. Signs of outer bearing failure are skid marks on the cones and one or more locked cones.

The *inner bearings* (the inside roller bearing and nose bearing under the nose of the cone) can fail when a bit is drilling a formation that is too hard for it. In this case, the teeth wear down to a flat top (they suffer flat-crested wear) and, as a result, the ROP slows. The driller then adds more weight to keep up the rate of penetration. The extra weight can stress the bearings beyond their design limitations.

Another cause of inner bearing wear or failure may be gauge rounding. The stronger gauge cutters wear away so much that the forces of weight and rotation on the bit shift to the weaker inner cone teeth and bearings. Because the inner bearings are smaller and not as strong as the outer bearings, they cannot withstand the extra force.

Reaming out an undergauge hole also stresses the inner bearings. The driller can partially or completely eliminate inner bearing failure by using a bit designed for harder formations, reducing the time the bit is in the hole, decreasing the rotary speed, or choosing a special bit for reaming.

Both the inner and the outer bearings can fail if the weight on bit is too high, the rotary speed is too fast, the bit is used to ream under-gauge hole, an abrasive drilling fluid is in use, or the bit is used too long.

Diamond Bits



Diamonds are the hardest mineral on earth, almost nine times harder than the next hardest naturally occurring mineral. A diamond will outwear or cut anything without affecting the diamond in any way, with only two limitations: it will disintegrate if the temperature is too high, and it is brittle and is therefore susceptible to fracturing under shock loads.

It is no surprise that tools set with whole or crushed diamonds are common in many industries where a hard material needs to be cut, ground, or polished with precision. For example, tools used in manufacturing cars, airplanes, and space vehicles, cutting glass in the optical industry, or for surgical instruments may use diamonds. Bits for oilwell drilling with natural diamond cutters date from the 1940s.

Diamond tools might be common in every home workshop except for diamonds' rarity and the expense of mining them. As early as 1797, therefore, scientists began trying to create, or synthesize, diamonds from carbon (diamond is pure carbon, as are coal, ash from burning bones or wood, and soft graphite used in pencil leads). Research scientists at General Electric were the first to succeed, in 1954. Synthetic diamonds turned out to be even more expensive to manufacture than natural diamonds are to mine, but as long as the demand exists, manufacturers can produce them because carbon is plentiful.

The synthetic diamonds used now in bits are one of two types: the *polycrystalline diamond compact* (PDC) developed in the early 1970s, and the *thermally stable polycrystalline* (TSP), first made in the late 1970s. Manufacturers produce bits with natural diamonds, PDCs, TSPs, or combinations of these as the cutters, replacing the teeth or inserts of roller cone bits.

The polycrystalline diamond compact, or PDC, is one of the most important advances in recent years. Since their first production in 1976, bits using PDC cutters have become as common as roller cone bits. Each polycrystalline diamond compact, which is the cutter, is a special type of synthetic diamond bonded to tungsten carbide (fig. 60).

To manufacture a PDC, a special furnace heats carbon to a very high temperature and, under great pressure, forms many tiny (about 0.00004 of an inch, or 0.00102 of a millimetre) diamond crystals ("poly" means "many"). The manufacturer then mixes the diamonds with a metal powder, called the catalyst metal, and puts the mixture into a can. A layer of tungsten carbide powder mixed with diamond is added, and, finally, a polycrystalline wafer is put on the top.

The manufacturer then seals the can and heats it under high pressure. The pressure and heat cause the diamonds to bond with each other and with the tungsten carbide to make a polycrystalline diamond compact (a compact is any object produced by compressing metal powders). The tiny diamond crystals in a PDC face in different directions, which makes the PDC very strong, sharp, and wear-resistant. It is self-sharpening because when a layer of crystals wears away, another layer with its many sharp edges is exposed.

The main disadvantage of PDCs is that they are even less stable at high temperatures than are natural diamonds. As the PDC contacts the rock during drilling and heats up, the catalyst metal expands at a different rate from the diamond. Eventually, when the temperature reaches about 1,350° F (750° C), the PDC cracks. This temperature is not difficult to reach in drilling and is much lower than the temperature at which a natural diamond disintegrates (2,350° F, or 1,270° C).

Synthetic Diamond Bits

PDC Bits

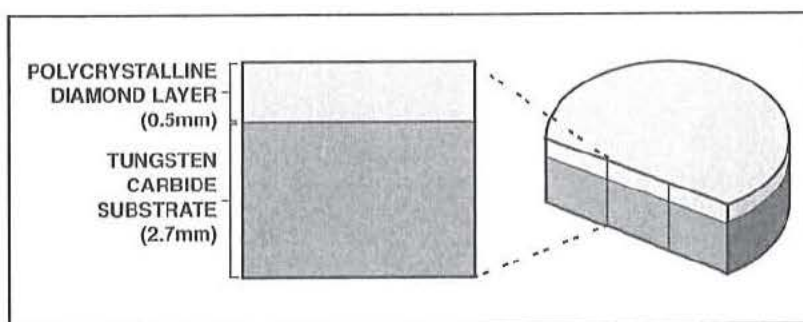


Figure 60. A polycrystalline diamond compact (PDC)

The stud protrudes from the body of the bit. The extra support that the tungsten carbide post gives the cutter makes the stud design stronger than the cylinder cutter, and more of the cutter actually digs into the formation.

Because the PDC cannot withstand the heat used to cast the matrix body of the bit, the cylinder cutter is brazed into a pocket in the bit after casting. Stud cutters are essentially already in their own pockets (the stud) and the whole piece is brazed or press-fitted (snapped into a tight cavity) onto the bit.

The cutters sit in the bit at certain angles called *rake angles*. The *back rake angle* is how far the cutter leans back from the vertical, away from the rock it is cutting (fig. 66). A cutter that is perpendicular to the formation has no back rake angle. A cutter that tilts forward into the rock has a positive rake, but this angle is not practical.

The amount of back rake determines the aggressiveness of the cutter—no back rake is the most aggressive. Harder formations require more back rake to prevent the cutter from breaking and to reduce chatter, or vibration. Even on the same bit, cutters at different locations may have different back rake angles to help distribute the load among the cutters. Back rake also affects how much weight on the bit is practical—the greater the back rake angle, the less the WOB influences the action of the bit and so the more uses the bit has under different conditions.

The *side rake angle* is the left-to-right orientation of the cutter with respect to the bit's face (fig. 67). The designer angles the cutters toward the outside of the bit to help direct the cuttings toward the annulus, so that the cuttings do not pass in front of the cutter again to be reground. The optimum side rake angle improves the cleaning and drilling efficiency of the bit. It also helps to stabilize the bit to keep it from vibrating.

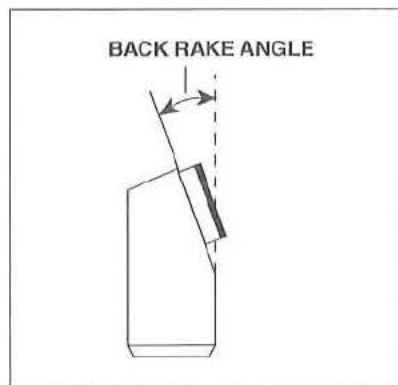


Figure 66. Back rake angle

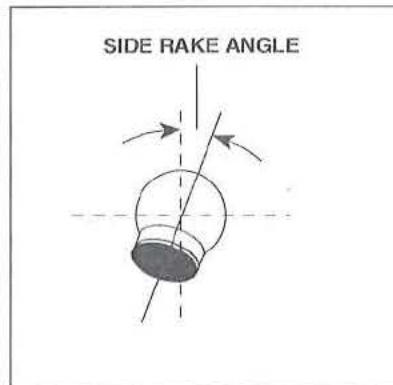


Figure 67. Side rake angle

The most obvious design difference between natural diamond bits and PDC bits is how the cutters fit into the bit. PDC cutters sit sideways inside pockets, either individually or on blades that are part of the body of the bit (fig. 68). In this way, they look more like one cone of a steel-tooth roller cone bit than like a natural diamond bit.

Bits with the PDCs arranged individually all over the surface are sometimes called porcupine bits. Bladed PDC bits can have from three to more than twenty blades, each with many or only a few cutters. The more blades and cutters, the more durable the bit is, but the slower the penetration rate.

Hydraulics

The design of the hydraulic system is more critical in PDC bits than in other types. PDCs cut deeper than natural diamonds because they are larger, which produces more cuttings to clear away. The cooling function of the drilling fluid is also crucial because of a PDC's thermal weakness. The harder the formation, the more important the cooling function is to prevent the cutters from disintegrating. The softer the formation, the more important the cleaning function is to prevent balling.

Like roller cone bits, PDC bits use jet nozzles as outlets for the drilling mud (fig. 69). The nozzles come in various sizes and are usually interchangeable (but not with roller cone bit nozzles). The nozzles direct the cuttings into *junk slots* on the outside diameter of the bit. The junk slots work like the collectors on natural diamond bits—that is, they provide a low-pressure area that pulls the fluid with the cuttings up and away from the nose of the bit.

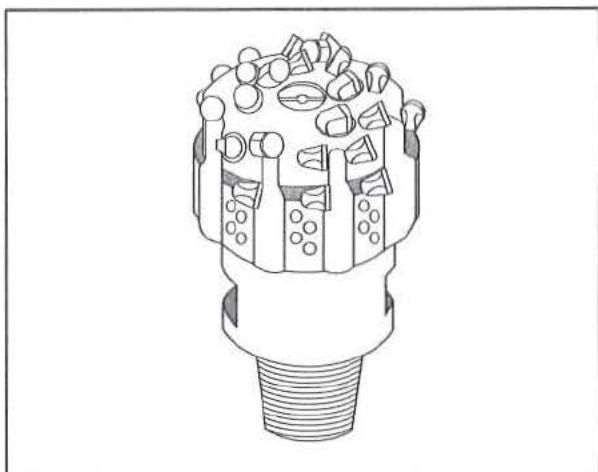


Figure 68. PDC cutters in the body of the bit

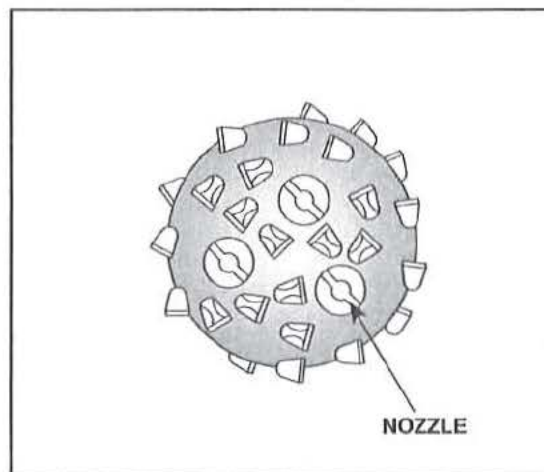


Figure 69. Jet nozzles on a PDC bit

Each nozzle usually points toward the bottom of the hole or at a slight angle and cleans and cools a group of cutters or, on some bits, a single cutter. The number of nozzles depends on the design of the rest of the bit. For instance, the designer can put fewer nozzles on a bit with fewer blades because the cutters are more exposed and the fluid can reach them more easily.

The newest synthetic diamond for bits is the thermally stable polycrystalline diamond, or TSP. Its method of manufacture is similar to that of the PDC. The difference is that the manufacturer either leaches out the catalyst metal that in a PDC helps bond the crystals or replaces it with a less-temperature-sensitive material.

TSP Bits

A TSP is stable at higher temperatures than a PDC (almost as stable as natural stones) because the crystals do not break apart because of expansion. Where a PDC's diamond layer will disintegrate at 1,350° F (750° C), the TSP can withstand temperatures up to 2,200° F (1,200° C). The TSP, like the PDC, stays sharp as the tiny diamond crystals wear away.

A TSP bit is more like a natural diamond bit than a PDC bit is because a TSP is much smaller than a PDC and closer in size to the natural diamonds used in bits (only 1/3 carat, about 1/12 inch, or 2 milli-metres, in diameter). The TSP may be round or triangular (fig. 70). It usually functions on the bit as a cutter by itself, like a natural diamond, and is cast into the matrix, rather than being brazed into pockets, as PDC cutters are. It does, however, sit sideways in the bit like a PDC.

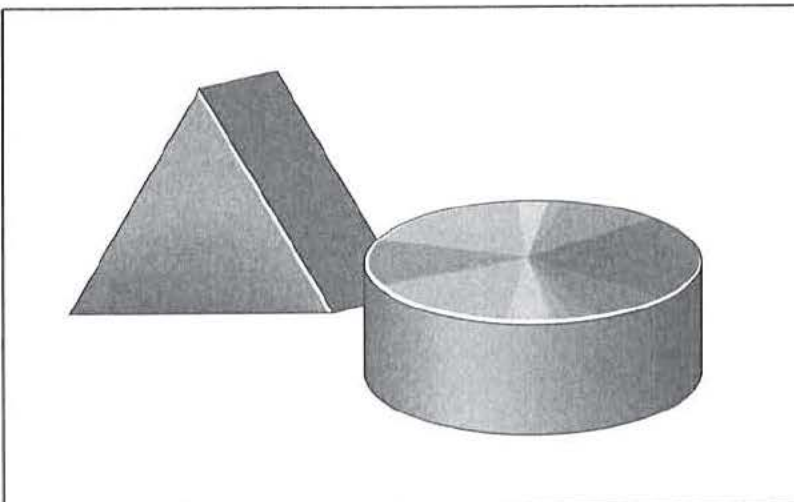


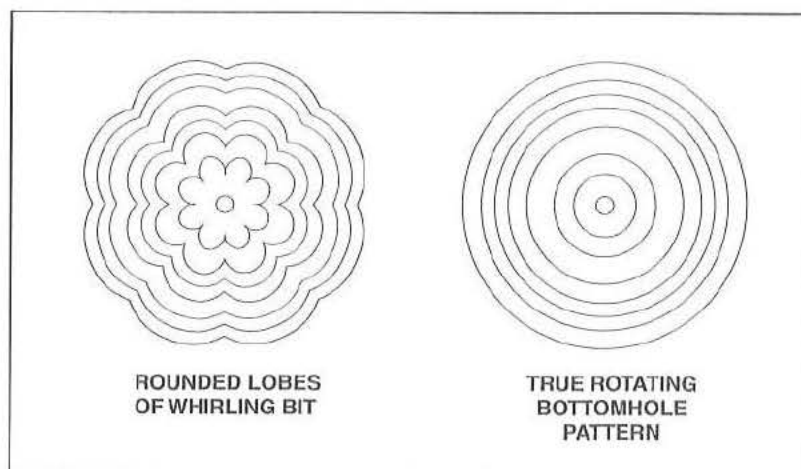
Figure 70. TSPs are triangular or round in shape.

The designer must solve the problems of where and how to place the diamonds, which type of diamond to use (natural or synthetic), and how to design the rest of the bit so that the diamonds do not break from impact or disintegrate from heat. The driller must then use the bit in the correct formations and under the proper conditions. Designers now use computers to help predict where and how a bit will wear. Some manufacturers can even produce custom bits for a specific drilling operation.

Diamond bits are very expensive, so avoiding preventable wear is important. Some of the same types of damage described for roller cone bits can affect the cutters, the gauge surfaces, and the body of a diamond bit. Some types of damage, however, are unique to diamond bits, because of diamond's low impact strength.

In 1989, a major operating company identified a phenomenon called *bit whirl* as one of the main causes of damage to diamond bits. Bit whirl can be a problem for any bit, but it is especially damaging to PDC bits. The bit whirls when its center of rotation is not in the center of the hole. Instead of rotating in a circular motion, the bit turns with a spiraling action (fig. 73). Because of the bit's spiraling action, the center of rotation at any given instant can be one of the gauge cutters. While whirling, the innermost cutters move backward and the gauge cutters pound against the side of the hole. This pounding breaks the cutters. The bit also drills an overgauge hole when it whirls.

Whirling can have several causes, including poor drilling practices. Once it begins, it is difficult to stop. It tends to happen at high rotary speeds and at low WOB. Also, any time a bit drills slowly, as, for instance, it often does in a very hard formation, whirling can occur. Manufacturers have, however, designed special antiwhirl bits to solve the problem.



Diamond Bit Wear

Figure 73. Bottomhole pattern caused by bit whirl and normal rotation

Roller Cone Bits

The method of determining the best weight and rotary speed is the same for steel-tooth and insert bits. The WOB in softer formations usually must be relatively light to avoid balling. But the driller can compensate for the reduced weight, and keep a good penetration rate, by using a faster rotary speed and high-velocity drilling mud circulation for good cleaning.

Rotary speeds of 200 to 250 rpm are not uncommon for steel-tooth bits. The abrasiveness of a formation, however, limits the rotary speed much beyond 250 rpm. Very fast speeds coupled with abrasive particles increase the wear on steel teeth and bearings. Also, insert bits require slower speeds because, at very fast speeds, the inserts can break because of impact shocks. Insert bits will run up to 180 rpm.

Roller cone bits in harder formations require a heavy WOB to crush the rock. Remember that the cutters on rock bits are shorter and closer together and do not shovel the formation, but rather penetrate it like a pointed chisel. In theory, the more weight applied to these chisels (up to their breaking point), the better they work. Of course, the heavier weight stresses the cutters and bearings and wears them out sooner. Another reason to increase the weight on bit when using steel-tooth bits is to maintain an economical drilling rate as the teeth become duller. A heavier weight allows the bit to work longer before the driller must replace it.

Running times vary with the formation and type of bit as well. A steel-tooth bit may last 30 hours in a soft formation. A tungsten carbide insert bit can last as long as 300 hours. Sometimes, therefore, only one or two tungsten carbide bits can drill a well to final depth.

Diamond bits require a lighter WOB than roller cone bits, but the driller still adjusts the WOB and rotary speed to obtain the lowest cost per foot (metre) of hole drilled. The specifications that the manufacturer supplies with a bit will recommend a range for the rotary speed.

PDC bits can drill very fast—up to 200 feet (60 metres) per hour—in soft, nonabrasive formations because the cutters shear deeply into the rock on each rotation. Matrix-body PDC bits resist erosion well and typically run for 300 hours or more. Occasionally, in soft formations, one bit may drill several thousand feet (metres) in each of several wells. PDC rotary speed is generally between 80 and 160 rpm. A driller may rotate a bit made up on positive displacement tool as fast as 600 rpm, or one made up on a turbine as fast as 1,000 to 1,200 rpm.

Natural diamond bits have the slowest penetration rate, 5 to 15 feet (1.5 to 4.5 metres) per hour, because they are grinding very hard formations and drill only a small amount of rock on each pass. They use the lightest weight on bit and relatively high rotary speeds, usually 120 to 140 rpm. Because they drill slowly and because they are often used in the most abrasive formations, they typically last for only 1,000 to 2,000 feet (300 to 600 metres). Keep in mind, however, that even if an expensive diamond bit drills only 50 feet (15 metres) in a given formation, it still performs better than a roller cone bit that would have drilled only 10 feet (3 metres) in the same formation before it wore out.

TSP bits can run up to 30 feet (9 metres) per hour, which is faster than natural diamond bits but does not approach the rate for PDC bits. The WOB and rotary speed for TSP bits fall between those used for PDC and natural diamond bits.

Diamond Bits

Glossary



abrasion *n*: wearing away by friction.

air bit *n*: a roller cone bit that is specially designed for air or gas drilling. It is very similar to a regular bit, but features screens over the bearings to protect them from clogging with cuttings and thicker hardfacing on the shirrtail to protect them from abrasive, high-velocity air or gas drilling fluid.

air drilling *n*: a method of rotary drilling that uses compressed air, instead of water or mud, as the circulating medium; called gas drilling if compressed natural gas instead of air is circulated.

alloy *n*: a substance with metallic properties that comprises two or more elements in solid solution.

annular velocity *n*: the speed at which the drilling fluid is traveling in the annulus of a well.

annulus *n*: the space between the drill string and the wall of the hole or the casing.

antiwhirl bit *n*: a specially designed fixed-head bit with a pad on the bit's gauge surface that unbalances the bit and moves the center of rotation to the pad.

back rake angle *n*: in a PDC bit, the amount of distance, in degrees, between vertical (90°) and the face of the cutter.

ball bearing *n*: a bearing made up of several relatively small steel spheres that rotate freely in a groove, or race, and convert sliding friction into rolling friction. Compare *journal bearing*, *roller bearing*.

balled-up bit *n*: a bit on which a mass of sticky consolidated material, usually drilled cuttings, has accumulated.

ball race *n*: a track, channel, or groove in which ball bearings turn.

barite *n*: barium sulfate, BaSO_4 ; a mineral frequently used to increase the weight, or density, of drilling mud.

bearing *n*: see *ball bearing*.

bearing pin *n*: a cylindrical projection from each leg of a bit onto which the bit's bearings are mounted.

bed *n*: a specific layer of earth or rock that presents a contrast to other layers of different materials lying above, below, or adjacent to it.

bentonite *n*: a colloidal clay, composed primarily of montmorillonite, that swells when wet. Because of its gel-forming properties, bentonite is a major component of water-base drilling muds.

A

B

S sealed bearing *n*: on a roller cone bit, a type of bearing that is not exposed to the drilling fluid in the wellbore. Instead, a synthetic rubber ring is placed between the outside of each cone and the shirrtail of the bit where the cones reside. This seal prevents drilling fluid from entering the space between the cone and shirrtail and thus the bearings, which lie inside the cones. Sealed bearing bits must also contain a built-in reservoir of grease since they are not lubricated by the drilling fluid.

shallow-cone profile *n*: the shape of a PDC bit's head that resembles two short and rounded cones placed side by side. The compacts are placed on the surface of the head. Compare *parabolic profile*, *short parabolic profile*.

shear bit *n*: see *fixed-head bit*.

shirrtail *n*: the part of a drilling bit on which the cone is anchored. Shirrtails extend below the threaded pin of the bit and are usually rounded on bottom.

short parabolic profile *n*: the shape of a PDC bit's head in which the head resembles a short parabolic arc. A parabolic arc is an arch-shaped curve that looks similar to the arch over a doorway or other structure. Compare *parabolic profile*, *shallow-cone profile*.

shrouded jet nozzle *n*: a special type of jet nozzle that is manufactured with a projection (the shroud), which serves to minimize the erosion of the nozzle by the high-velocity jet of drilling fluid being forced through it.

side rake angle *n*: in a PDC bit, the left-to-right orientation of the cutter with respect to the bit's face; usually, the cutters are angled toward the outside of the bit to help direct cuttings to the annulus.

sidetracking bit *n*: a specially designed bit, usually made up on a downhole motor, that is used to drill a directional or horizontal well.

spall *n*: a condition in which the surface material of a bit bearing separates from the bearing's core material. Bearings spall when the metal of which they are made fatigues because of overuse.

spud bit *n*: a special kind of drilling bit with sharp blades rather than teeth. It is sometimes used for drilling soft, sticky formations.

steel-tooth bit *n*: a roller cone bit in which the surface of each cone is made up of rows of steel teeth. Also called a milled-tooth bit or milled bit.

stickiness *n*: the characteristic of a soft formation to adhere (stick) to the bit as the formation is drilled.

stiff drilling assembly *n*: a collection of downhole tools arranged in the drill stem above the bit to keep the hole on course. In general, a stiff drilling assembly consists of stabilizers and large-diameter drill collars. Also called packed-hole assembly.

stringer *n*: a relatively narrow section of a rock formation that interrupts the consistency of another formation and makes drilling that formation less predictable.

sub *n*: a short, threaded piece of pipe used to adapt parts of the drilling string that cannot otherwise be screwed together because of differences in thread size or design. A sub may also perform a special function, such as a bent sub, which deflects a downhole drilling motor off-vertical to begin drilling a directional hole.