

SPE 10893

Design, Application, and Future of Polycrystalline Diamond Compact Cutters in the Rocky Mountains

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Member SPE-AIME

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ABSTRACT

The Rocky Mountain Region has proven to be one of the greatest challenges to manufacturers of bits utilizing Polycrystalline Diamond Compacts (PDC) as cutting elements. Constant advancements in bit design, and further exploration of possible drilling applications has proven to the industry that PDC bits have a place in Rocky Mountain Drilling. The knowledge of what makes a PDC bit drill is essential for everyone connected with the application of this bit. An understanding of terms such as back rake, side rake, exposure, and profile, is necessary to correctly select the right style of bit.

The type of chip generated by the cutter is dictated by the characteristics of the rock being drilled. We can control this generation of cuttings by orientation of the cutter face. This orientation is controlled by exposure, side rake, back rake, and cutter density. Differing profiles can enhance directional characteristics and improve the cleaning of the bit. Setting up a proper hydraulics program for the bit, the rig, and the formation is critical in optimizing bit performance.

Running procedures used with PDC bits are similar to those used in diamond drilling, which includes careful setting of a bottom hole pattern, light weights and low RPM's while reaming. Drilling weights and RPM's are determined by optimum rates of penetration, keeping in mind that the shearing action of the PDC cutter requires considerably less weight than conventional bits to fail the rock. With the increasing performance and success rate achieved in just the last year, the future of PDC drill bits is very promising in the Rocky Mountain Region.

INTRODUCTION

A new type of drill bit has been introduced in the Rockies in recent years. These bits are of high-technology revival of one of the first bit styles used for rotary drilling...the drag bit. The earliest rotary drag bits were usually 2 or

3 blade fishtail bits, having hard metal blades with cutting edges dressed at various angles depending on the formation being drilled.

The modern version of the drag bit utilizes numerous small cutting elements instead of 2 or 3 straight continuous blades. The cutting elements are known as polycrystalline diamond compacts, of which General Electric Company's Stratapax[™] drill blanks, (Figure 1) are probably the best known example. The cutting edge is composed of a thin layer of tiny synthetic diamonds which are cemented to a tungsten carbide backing in a high temperature, high pressure process. The diamond layer is approximately 1/2 inch in diameter and about 1/64 inch in thickness. It contains numerous small diamond crystals bonded together, each with it's cleavage plane randomly oriented relative to the neighboring diamond crystals. This prevents any shock induced breakage in an individual diamond crystal from propagating through the entire cutter. The result is a wafer thin diamond layer with the hardness and abrasion resistance of a diamond, and the impact resistance of tungsten carbide.

The first polycrystalline diamond compacts (PDC), were first developed as a metal cutting tool. Early in 1973, the General Electric Company begin experimenting with sintered polycrystalline diamond compacts as cutting elements in drag bits. Since then, the novel drilling tool has become a proven drill bit. In 1981, over 3 million feet of hole was drilled with PDC drill bits in the free world.

CUTTER ORIENTATION

The efficiency of drilling with a PDC bit is dependent upon the actual angle of attack between the cutter and surface of the formation. The formation being drilled will depict the proper cutter orientation. To understand that cutter orientation is the most critical factor for the formation being drilled, one must define three basic terms associated with PDC bits; back rake, side rake, and chip clearance or cutter exposure. (Figure 2).

References and illustrations at end of paper.

Unlike a conventional drill bit, which drills with a fracturing or crushing effect, the PDC cutter cuts with a shearing action. Rock will fail with significantly less energy in shear than in compression thus, a more efficient drilling action with less weight on the bit. The shearing action of the cutter is similar to that of a machine tool, and the cuttings produced in a soft or plastic shale closely resemble that of metal cuttings from a lathe. Cuttings in a plastic formation will actually curl up in front of the cutter. Unlike the round, or polygonal shape or brittle rock cuttings, the shale cuttings recovered from the shale shaker contain many curved segments. The curved segment has a smooth convex side and a peeled, concave side, a feature closely resembling that of metal cuttings.

In soft or plastic formations, and where the cutter exposure is inadequate, the cuttings have a tendency to move up the cutter face and impact the bit body. As the bit continues to drill, the cuttings will pack in front of the cutter and cause bit balling. This will actually push the bit body upwards and thus reduce the actual bit weight applied to the cutters.

To insure that the cuttings can be generated without interference from the body itself, adequate clearance, or "exposure" is necessary. This can be accomplished by the use of a fluid course, or extending the cutting edge out away from the body. When large exposures are used, the velocity of the fluid on the face of the bit is reduced, and cleaning effect is also inhibited. Now we must mechanically push the cuttings from the cutter face.

This mechanical effect is accomplished by turning the cutter to act like a snow plow. This is called "side rake." As previously mentioned, the chips generated by soft or plastic formations are very similar to that formed in metal cutting. In the machine tool, the side rake is a standard feature of the tool which facilitates chip removal.

The third and final cutter orientation is called "back rake", defined as the angle made by the cutting face and a line perpendicular to the cutting surface. Back rake allows a bit designer to establish the proper cutting angle to match particular formations. Experience with the old steel and tungsten drag bits has taught us that small back rake angles in soft formations and larger angles in harder formations would produce better penetration rates and longer bit life respectively.

The importance of back rake can be demonstrated in the laboratory, using high speed photography. In single cutter experiments, the effects of various back rake angles can be easily demonstrated for various formations. (Figure 3).

Cutter orientation becomes a dynamic effect when viewed by the formation being cut. The proper combination of side rake, back rake, and exposure delivers the most effective cutting angle, loading and drag upon the cutting edge. These factors control the aggressiveness and wear that is induced by the shearing action of the cutters. In soft, non-abrasive formations where cutter wear is very slow, the orientation can be set to emphasize aggressive cutting and even loading. Harder formations create high temperatures at the cutting edge which will thermally

damage the cutting edge and accelerate wear. This heat must be controlled by back rake, and by loading the cutters according to each cutter's varying velocity.

CROWN PROFILE

A bit's profile can play an important role in the performance of a PDC drill bit. The profile will have a tremendous effect on bit cleaning, stability, and hole deviation control.

The double cone profile will maintain a straight hole even in crooked hole country. (Figure 4) This profile incorporates two modes of cutting, drilling, and reaming. The sharp nose will attack and drill the formation aggressively, while the apex and reaming flank stabilizes the bit. Not only will this profile control deviation, but will also reduce the hole angle in already deviated holes.

A shallow cone profile proves to be the easiest to clean due to the concentration of hydraulics on the reduced surface area of the crown. (Figure 5) The shallow cone profile must rely heavily upon the gauge for directional stability since the cutters are virtually on a single, flat plane. When used in conjunctions with a sufficient gauge length and a proper bottom hole assembly, this profile has been extremely successful in holding angle and direction, even in directional holes in excess of 40°. The result has eliminated an extra motor run for course correction normally required to hit the target.

HYDRAULICS

With any type of drill bit, proper hydraulics is the key in assuring that the bit will drill up to it's capacities. The actual locations of the cutters on a bit are chosen in conjunction with the number and placement of the nozzles in the bit face, the junk slots at the gauge of the bit, and the nature of the formation to be drilled. The nozzles are the fluid "sources" introducing the drilling fluid at selected points, while the junk slots are the fluid "sinks" which allow fluid and cuttings to be circulated from the bit face. The nozzles and junk slot placements are prime considerations determining the basic flow pattern across the bit face. The interaction of this flow pattern, with the consequent cutter placements, must be such to allow the flow to be best utilized for optimum cleaning and cooling of the cutters.

The action of the cutter moving through the rock is such that it can be described as a "positive displacement cutter". The rock chips and cuttings are lifted from the bottom of the hole and shoved ahead or aside, depending on the cutter orientation. The size and strength of the cuttings which can be produced in shear require tremendous turbulence to effectively scrub them clear of the cutting surface and bit.

In soft formations, penetration rates are usually limited only by hydraulic cleaning. This has been seen both in the field and the research laboratory. (Figure 6) As pump volume or hydraulic horsepower is decreased, evacuation of the cuttings slows and the drilling rate declines as a result of regrinding the cuttings. This demonstrates that the mechanical cleaning of the cutters is inefficient at high

penetration rates. Figure 6 displays this relationship between flow rate and penetration rate in soft formations. The turbulent scrubbing of the cutters associated with high hydraulic horsepower becomes the controlling factor in bit performance.

The importance of cutter orientation is pronounced in soft formation drilling. Large cutter exposures help keep the cuttings off and away from the formation, and from contacting the bit body, which can lead to bit balling. The results of adequate exposure for soft formations can be seen in Figure 7.

With the close proximity of the nozzle to the formation in PDC bits, the effects of high velocity jetting can be maximized to enhance performance. The superior hole cleaning properties and performance of extended nozzles in roller bits has been proven in the field. PDC bits utilize the extended nozzle concept in every bit. Correct nozzle selection is very critical to insure optimum use of the hydraulics as both a cutting and a cleaning tool. The dramatic effect of high bit pressure drops and high velocity jetting is easily proven in the field. (Table 1).

High velocity turbulence is more effective in cleaning the large surface area of the bit's cutting face than high flow rates alone, which have a tendency to channel. Flow rates should be kept within a range which will not promote hole erosion. Using an acceptable flow rate, the nozzle selection should be made to maximize the available standpipe pressure.

When optimizing the hydraulics, hydraulic horsepower is a good guide in maximizing parameters. Sufficient flow rates to clean the hole for the anticipated rate of penetration is used in conjunction with the highest hydraulic horsepower attainable, within the rig's pump limitations. PDC bits often have more than the three nozzles common on tricone bits. In cases where low flow rates make desired bit pressure drops impossible unless extremely small nozzles are used, care should be taken to avoid nozzle plugging.

SPECIAL APPLICATIONS

PDC bits have been used and purposely designed for special applications in drilling. The mechanics of the bit lend itself well for use with downhole motors and turbines because the bit has no moving parts to be left in the hole. This has made it a perfect match for straight hole drilling with mud motors and turbines. The theoretical cutting action of a PDC bit is a straight line relationship between penetration and RPM. This means, the faster you can turn the bit, the faster it will drill, providing the bit can be adequately cleaned. In reality, the weight on the bit must also be increased with an increased in RPM to overcome the strength of the rock.

A bit with the double cone profile was recently used in the Williston Basin to turn the hole using a mud motor. The bit saved \$37,800 over a comparative journal bearing, insert bit run. Numerous straight hole drilling applications with mud motors have proven to be economical in Wyoming, Colorado, and Utah. (Table 2)

PDC cutters have also been used on special side tracking bits with outstanding performances in offshore California, Oklahoma, and the Gulf Coast Region. (Figure 8) In offshore California, an 8½ PDC side tracker had an economical savings of \$31,000 over the straight hole drilling costs of the same section of the hole in an offset well.

Problems with swelling shale in Utah and Venezuela have promoted the use of PDC cutters on bi-center bits. (Figure 9) These bits are especially designed to drill a larger hole than that which the bit will pass through. This will insure easy passage through tight spots in swelling shales and creeping salt formations.

PDC core bits have made a name for themselves. (Figure 10) Increasing penetration rates and reducing the overall coring time has allowed additional footage to be cored at no more cost than allocated for conventional coring. Fluid invasion of the core has been minimized by face discharge nozzles and by the increased penetration rate.

RUNNING PROCEDURES

When running a PDC bit, it is a good practice to ream down the last couple of joints before reaching bottom. This will insure that the bit won't be run into fill, and possibly plugging a nozzle. Once the bottom of the hole is cleaned, care should be taken to set a new bottom hole pattern using light weights and low RPM's. After the bit has been seated about one foot into it's new hole configuration, weight and RPM can be increased until an optimum penetration rate is reached.

Weight should be applied slowly in 2,000 lb. increments. Any sudden large increase in bit weight will have a tendency to ball the bit in soft formations. The weight requirements for PDC drill bits are unique in that the bit drills in shear, so the weight required is almost always considerably less than the rock bit or surface set diamond bit.

If it is necessary to ream a tight spot, care should be taken not to damage the outside cutters by impact or overloading. This can be accomplished by using light weights and low RPM's.

CONCLUSIONS

The understanding of the mechanics and design of the PDC drill bit is essential for picking the proper style of bit for the particular application. Design of the bit will have a tremendous effect on the performance, since the success or failure of one style of bit does not necessarily mean success or failure of an alternative style. The key to assuring the best possible run from a PDC bit is optimizing the available hydraulics. This means utilization of the maximum allowable standpipe pressure at a sufficient flow rate to clean the hole. Some recent PDC bit runs in the Rocky Mountain Region are listed in Table 3. These runs demonstrate the economical advantage which can be achieved by these bits. Speciality applications have also been proven by saving time and money in the normally expensive, problem situations encountered in Rocky Mountain drilling.

REFERENCES

1. Iversen, R.; Huang, H.: "The Positive Effects of Side Rake in Oilfield Bits Using Polycrystalline Diamond Compact Cutters" SPE paper, 10152, 1981.
2. Cortes, J.; Besson, A.; "Behavior of Polycrystalline Diamond Compact Cutters While Drilling in Bottomhole Conditions - Field Applications".
3. Salzer, J.A.; Melough, J.F.; "Development of a Reductive Model for Drilling Pressurized Shale with Stratapax Blank Bits". Presented at ASME, Energy Sources Technology Conference, Houston, Texas, January 19-22, 1981.

TABLE 1

<u>Bit Size</u>	<u>Depth In</u>	<u>TFA</u>	<u>GPM</u>	<u>SP</u>	<u>Bit P</u>	<u>HHP</u>	<u>Nozzle Velocity</u>	<u>Penetration Rate</u>
8 1/2	12627	.32	462	2500	1900	9	460 ft/sec	6.2 ft/hr
8 1/2	13163	.24	415	3300	2900	12.5	560 ft/sec	12 ft/hr
8 3/4	5704	.32	400	2400	1400	5.4	400 ft/sec	60 ft/hr
8 3/4	6950	.24	400	3500	2500	9.8	540 ft/sec	113 ft/hr
8 3/4	6507	.45	460	2000	900	4	325 ft/sec	54 ft/hr

TABLE 2 - MUD MOTOR RUNS

<u>Formation</u>	<u>Hole Size</u>	<u>Depth In</u>	<u>Footage</u>	<u>Hours</u>	<u>Penetration Rate</u>	<u>Savings</u>
Niabrara sh & Moncos sh	8 3/4	5204	1546	202	7.65	\$26,127.00
Moncos & Niabrara sh	8 3/4	4119	1085	123	8.82	\$21,884.45
Moncos	8 3/4	4277	898	91	9.86	\$ 9,689.42
Fox Hills Tea Pot	8 3/4	6683	2242	171	13.62	No offset
Baxter	8 1/2	6490	228	25 1/4	9.0	\$16,385.00

Table 3 Recent PDC Bit Runs

State & County	Formation	Hole Size	Depth In	Footage	Hours	Penetration Rate	Savings
North Dakota, Billings, Co.	Dakota & Piper sand, shale limestone	8 3/4	6695	256	53 1/4	4.8	\$37,888
Wyoming Billings Co.	Hillard shale & sandstone	8 3/4	13647	1082	52	20.8	\$69,431
Wyoming Uinta Co.	Fox Hills & Tea Pot sand & shale	8 3/4	8925	2242	171	13.62	No offset
Wyoming Converse Co.	Blair - Baxter shale	8 1/2	12182	2570	334	7.6	\$38,319
Colorado Rio Blanco Co.	Upper Mesa Verde shale	8 3/4	3994	2010	138.5	14.5	\$24,824
Colorado Moffat Co.	Niabrara & Mancos shale	8 3/4	6750	1546	202	7.65	\$26,127
Colorado Routt Co.	Mancos shale	8 3/4	4277	728	63 1/2	11.46	\$50,676
Utah Uintah Co.	Mancos & Dakota shale & sandstone	6 1/8	8914	1201	80	15.01	\$39,804
Utah Summit Co.	Hilliard shale & sandstone	8 1/2	16,245	2498	153 1/4	16.3	\$275,230



Figure 1 - Polycrystalline Cutters

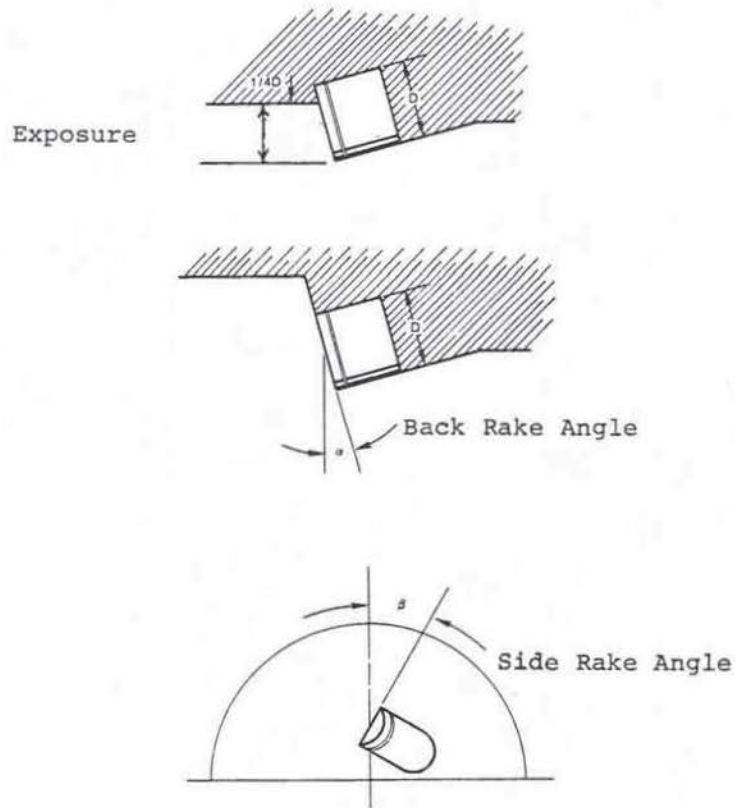


Figure 2 - Cutter Orientation

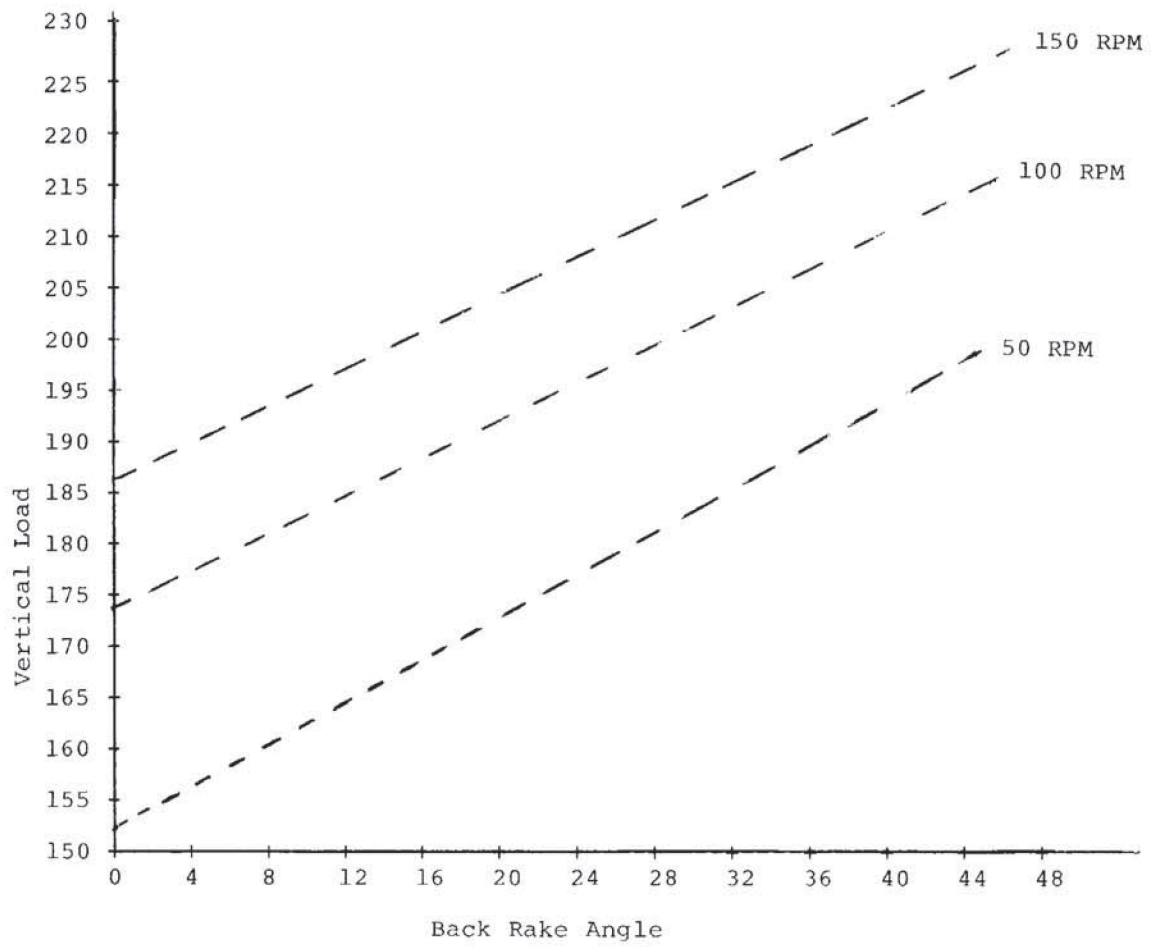


Figure 3 - Vertical Load Versus Back Rake Angle

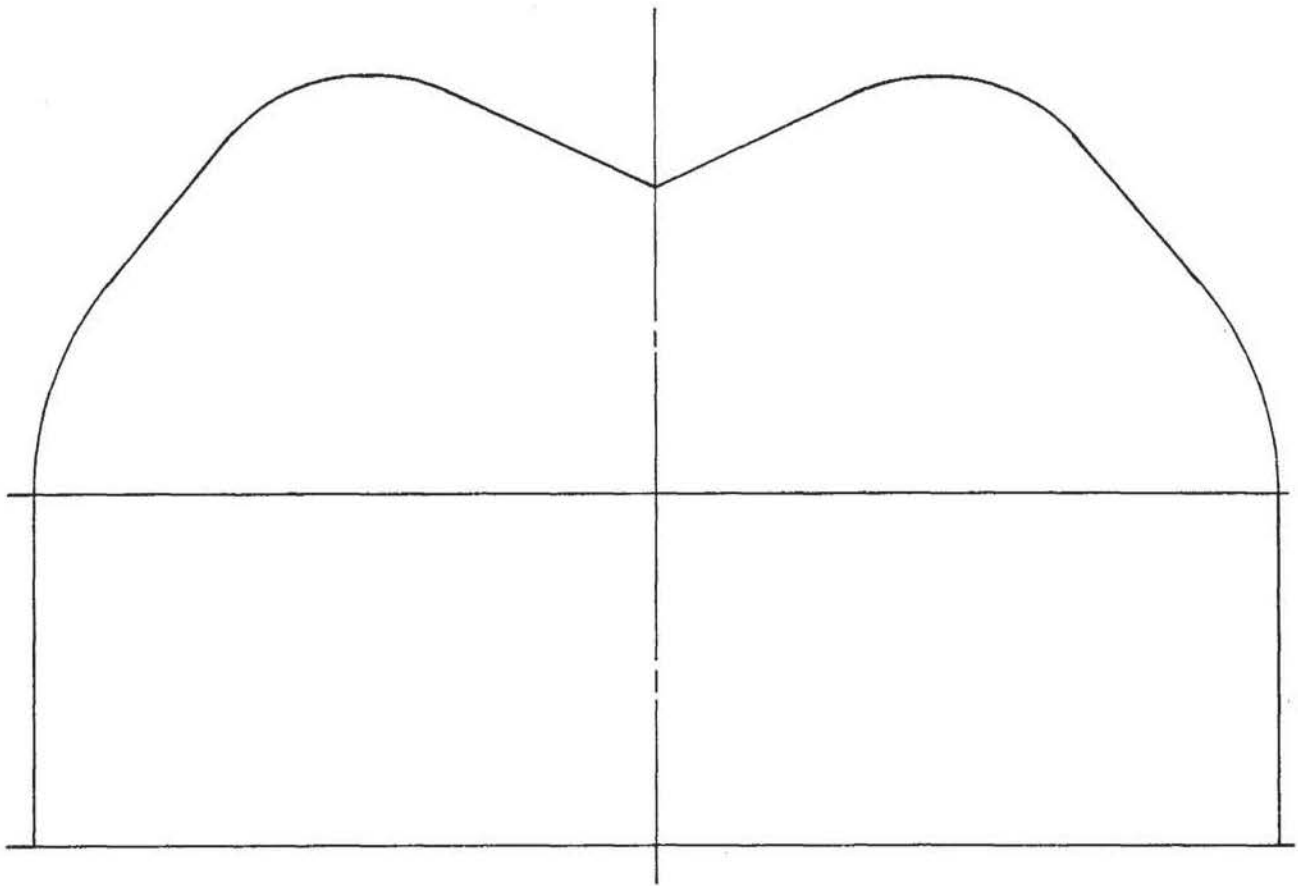


Figure 4 - Double Cone Profile

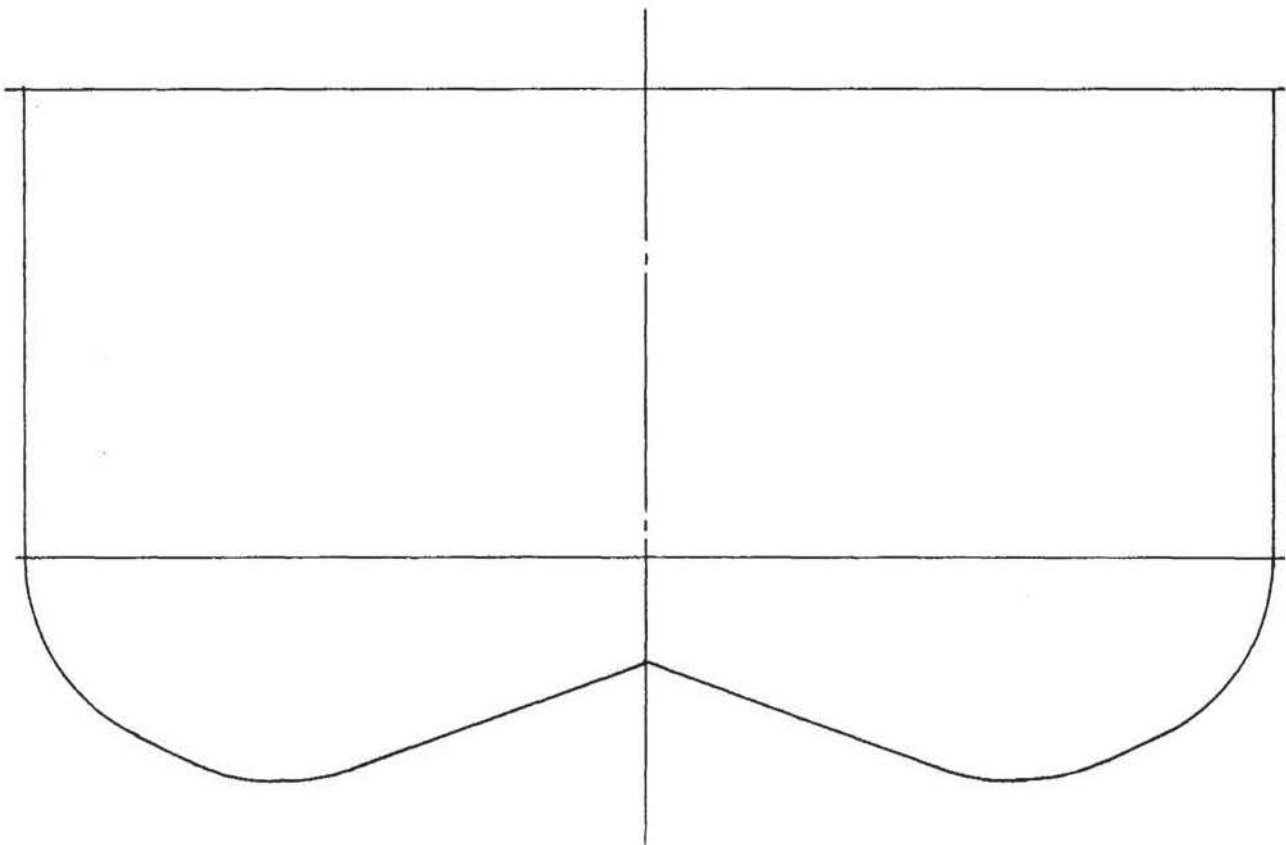


Figure 5 - Shallow Cone Profile

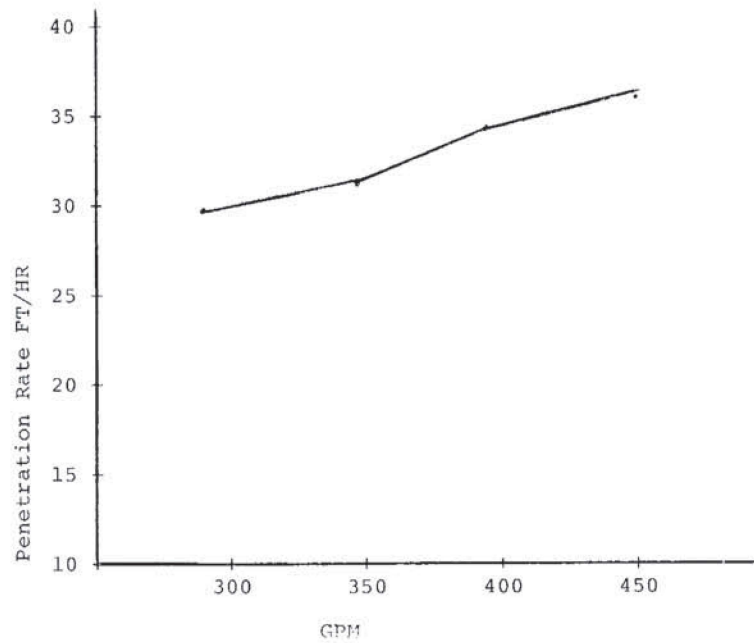


Figure 6 - Penetration Versus Flow Rate

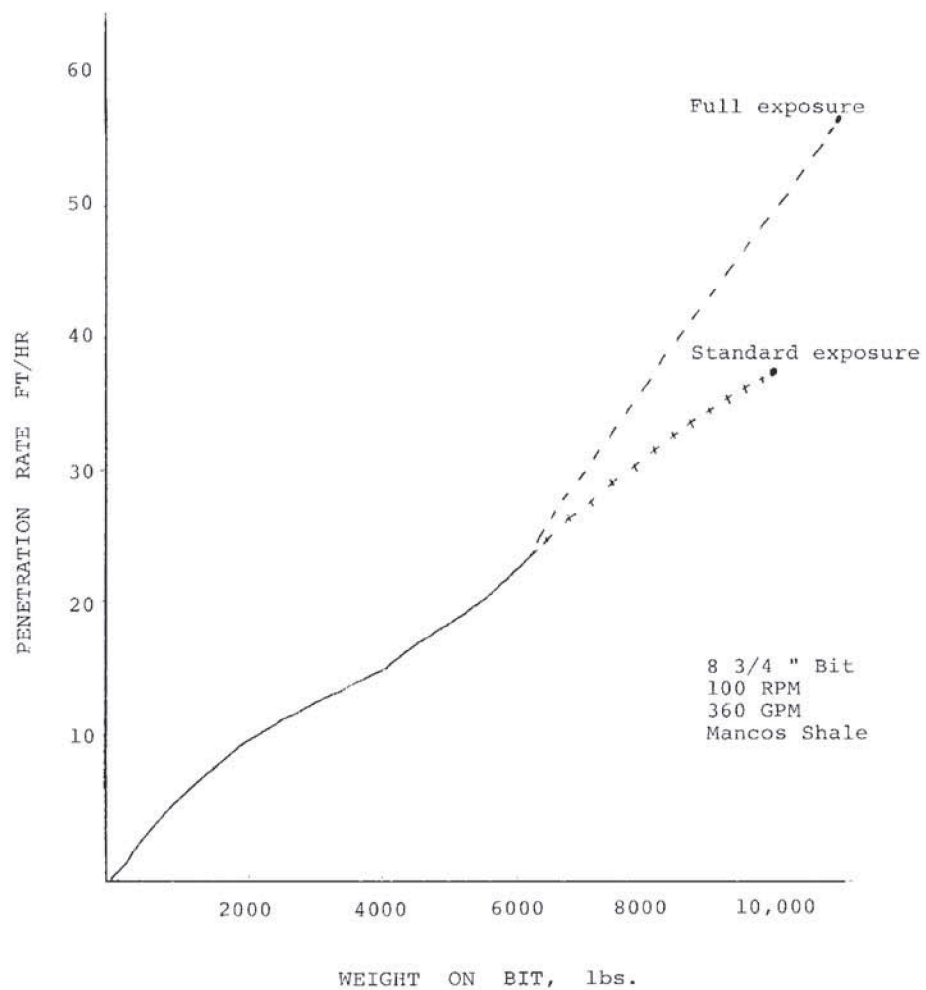


Figure 7 - Performance of full exposure vs. standard exposure



Fig. 8 — PDC sidetracker drill bit



Fig. 9 — PDC bi-center drill bit



Fig. 10 — PDC core bit