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## An Analysis of the Field Performance of Antiwhirl PDC Bits

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SPE Member

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### INTRODUCTION

"Bit whirl", the backwards whirling motion of polycrystalline diamond compact (PDC) drill bits, has been identified as a significant contributory factor in the premature failure of PDC bits in the field.<sup>1</sup> Two SPE papers have discussed bit whirl and the testing of various potential solutions,<sup>1,2</sup> and one described the field testing of PDC bits modified to produce a "low friction gauge".<sup>3</sup> This paper describes the design and subsequent testing in the laboratory and then in the field of a PDC bit designed from scratch to resist backwards whirling motion by incorporating various design features including the "low-friction gauge" concept described by Warren et al.<sup>2</sup> (described below as an "Antiwhirl bit"). It details the importance of the magnitude of the lateral component of the resultant cutting force on the bit and the angular extent of the bearing pads that react with this force, and describes and explains the directional behaviour of Antiwhirl bits in the field.

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References and illustrations at end of paper

### ANTIWHIRL BIT DESIGN

#### General

The 8 1/2" [215.9mm] diameter Antiwhirl PDC bit that is the subject of this paper is shown in figures 1 and 2.

The cutting forces arising from every PDC cutter on the bit are calculated using a mathematical model, which has itself been validated against laboratory tests. They are then summed vectorially to give the expected weight and torque requirements of the bit, together with the magnitude and direction of the lateral component of the resultant cutting force ("out of balance force"). The actual cutter positions on each bit, measured using a co-ordinate measuring machine, are input to this model to ensure that the performance of the bit is not compromised by any unfavourable build-up of manufacturing tolerance. In each of the laboratory and field tests described below, this measurement confirmed that the bit used had no cutters significantly out of position.

The PDC cutters are arranged so that the out-of-balance force is directed towards two large unaggressive (or "low friction") bearing pads. The absence of any aggressive cutting elements in the region of these pads should ensure that the bit does not start to whirl provided that the resultant force is directed towards them. This idea has been used in gun drilling for many years but was only recently introduced to rock drilling by Warren et al.<sup>2</sup>

The cutters are arranged so that the out-of-balance force always points towards the bearing pads, despite variations in formation type and penetration rate, and so that any perturbation of the axis of rotation of the bit (caused, for example, by forces arising from a formation change or other

inhomogeneity) generates a lateral force that tends to return the bit to its stable drilling mode as described above.

The bit has two to four secondary (diamond impregnated) cutters (as described by Williams and Thompson) <sup>4</sup> per blade opposite the bearing pad zone.

The bit profile is a shallow concave design, the transition from face to gauge being well away from the bit centre. This profile has traditionally been successful in formations with hard stringers. <sup>4,7</sup> The use of a profile similar to that used on standard products means that the effect of bit profile can be eliminated from any performance comparisons.

A fairly light-set design (28 cutters) was dictated by the choice of profile and requirement for a large cutter devoid area. If a PDC bit is drilling in a stable manner with a large depth of cut, it should be cutting more by "wedging" (Hughes) <sup>8</sup> and less by grinding and scraping, thus prolonging the life of the PDC cutters and allowing a lighter-set design.

Hydraulic design is intended to be as similar as possible to that of an existing bit design, to ensure that changes in hydraulic design do not influence performance data.

#### Magnitude of Out-of-Balance Force and Extent of Bearing Pads

The magnitude of the out-of-balance force and the angular extent of the bearing pads are dictated by consideration of likely variations in the magnitude and direction of the resultant side force on the bit. It should be noted that the resultant side force considered here and below does not include the reaction force from the borehole wall, which will be equal and opposite to it as long as the bit is in equilibrium. The variable effect of friction with the borehole wall should also be considered.

The out-of-balance force arising from the cutters can be calculated by various means (including those described by Glowka, <sup>9</sup> Warren and Sinor <sup>10,11</sup> and others) as can likely variations in out-of-balance force caused by cutter positioning errors, wear, variations in penetration rate, formation effects and so on.

The variations in the direction of the out-of-balance force caused by the above can be made small by proper design. There are, however, two further factors to be considered:

1. **Stability.** A bit with the out-of-balance force directed towards a "lowfriction" bearing pad may be in equilibrium, but is not necessarily stable. To make the bit stable, both lateral degrees of freedom must be considered and the bit should have at least one but ideally two bearing pads, spaced about the nominal direction of the out-of-balance force and

subtending an angle of around 90°. The Antiwhirl bit described has two such pads.

2. The second factor, which does not appear to have been considered in published work to date, is the effect of the side force imposed on the bit by the bottom hole assembly (BHA). The force rotates from the viewpoint of the bit, and must be added vectorially to the calculated out-of-balance force to produce a resultant side force  $F_R$  that must point toward the bearing pads regardless of the angular position of the force from the BHA.

Referring to figure 3, if  $F_I$  is the out-of-balance force and  $F_{BHA}$  the side force imposed by the BHA then in order for the resultant side force to point in the direction of the bearing pads, those pads must subtend a total angle  $\alpha$  where

$$\alpha \geq 2 \sin^{-1}(K) \quad (1)$$

where  $K = F_{BHA} / F_I$

and  $0 \leq K \leq 1$

the reaction pad being appropriately disposed about the out-of-balance force vector making due allowance for friction. The angle  $\alpha$  is plotted as a function of  $K$  in figure 4.

The magnitude of the resultant side force will vary between  $(1 - K) F_I$  and  $(1 + K) F_I$ . Thus for  $K$  greater than 1 the bit is bound to lift off the bearing pads once per revolution and will therefore will be ineffective as an Antiwhirl bit. For any value of  $K$  less than 1,  $F_R$  will theoretically always point toward bearing pads that subtend 180° or more, but such an arrangement is considered impractical. For the particular design described above a total bearing pad angle of 110° was chosen for practical reasons and reference to figures 3 and 4 will show that this bit can therefore tolerate a maximum theoretical imposed side force of 82% of the out-of-balance force.

In fact, the maximum tolerable imposed side force will be less than this theoretical value because of the small variations in the direction of the out-of-balance as described above.

The above means that the magnitude of the out-of-balance force should be as large as possible. Practical considerations, not least concern about wear of the bearing pads, mean that this magnitude is chosen, for the design above, to be 15 - 20% of the applied weight on bit (WOB).

#### LABORATORY TESTING

The first bit built to this design was laboratory tested under the same conditions used when a conventional PDC design, with similar profile and hydraulics, had previously been

tested. The results of testing this conventional bit are described in reference 3, where it is referred to as "bit C". No evidence of bit whirl was seen during tests of the Antiwhirl bit in Carthage limestone and in Bedford limestone.<sup>12</sup> There was no evidence of the lower frequency vibration associated with bit whirl - a strong signal at 17.2 Hz was observed when the conventional PDC bit was tested (figure 8, reference 3).

The Antiwhirl bit was found to have slightly higher specific energy than the conventional bit in laboratory tests. Specific energy is defined by Rabia et al<sup>13</sup> as:

$$SE = \frac{W}{A} + \frac{2 \pi NT}{AR} \quad (2)$$

The observed increase in specific energy was about 15%. Specific energy is dominated by torque, and an increase in torque requirement of 15% is quite predictable if the design is modelled. Part of the increase comes from increased cutter drag forces and part from friction between the bearing pads and the borehole wall.

When tested in shale, the Antiwhirl bit showed cleaning characteristics that were not noticeably better or worse than those of the conventional PDC bit.

## CONTROLLED FIELD TESTING

Following the successful laboratory test, a controlled test of the Antiwhirl bit was conducted under simulated field conditions at the Amoco site near Tulsa, Oklahoma. The test rig used is described by Warren and Canson<sup>14</sup> and the geology at the site by Winters, et al<sup>15</sup>.

The bit drilled from 250ft [76m] to 1544ft [470m], that is 1294ft [394m] at an average 67.0ft/hr [20.4m/hr]. It drilled further than the conventional design on which it is based which drilled 901ft [275m] before wearing to the point at which it could not be made to drill<sup>3</sup>. After drilling 1294ft [394m], the lighter set Antiwhirl bit was still drilling at 20.0ft/hr [6.1m/hr] and would have drilled further if it had not been decided to end the test and preserve the bit for further laboratory testing. Examination of the Antiwhirl bit after drilling the Oswego limestone showed no wear or damage. In contrast, the conventional bit showed chipping damage to 30 of its 34 cutters. The Antiwhirl bit then continued to drill with reduced wear and damage compared to that of this offset.

The bit condition after the test is shown in figure 5. Several cutters are spalled. It appears that this damage was caused by significant torsional vibrations ("stick-slip" motion).<sup>16-19</sup> Brett<sup>19</sup> suggests that dull bits are particularly prone to torsional vibrations. The large rubbing area of the bearing pad on an Antiwhirl bit may well affect the severity of torsional vibrations in a similar way. The situation may also

have been exacerbated by problems with the top drive which led to difficulties providing sufficient torque while drilling harder formations on this particular well.

Comparison of the condition of the bearing pads with that of gauge pads on the opposite side of the bit showed significant heat checking of the tungsten carbide inserts in the bearing pads with little or no damage to the inserts in the other gauge pads, confirming that the bit was pushed against the bearing pads while drilling.

Overall, the run was considered successful compared to conventional PDC offsets and further bits were built for field test.

## UNCONTROLLED FIELD TESTING - CASE HISTORIES

### Case History #1 - UK Sector, Southern North Sea

An Antiwhirl bit was tested in the Bunter shale<sup>20</sup>, Zechstein and Basal anhydrite<sup>21</sup> of the Southern North Sea. The bit was run in oil based mud and a packed BHA was used.

Problems were experienced drilling the float equipment, but once through this the bit drilled 2870ft [875m] at an average 82.5ft/hr [25.1m/hr] with no further problems. Penetration rate when pulled at TD after 20ft [6m] of Basal anhydrite was still in excess of 40.0ft/hr [12.2m/hr]. Table 1 compares this performance with conventional PDC offsets and shows that the bit performed extremely well. The penetration rate when pulled indicated the potential for future runs of greater length.

No problems with directional stability were reported, and the calliper log indicated that a gauge hole was drilled, improving conditions for logging tools, running casing and ensuring successful cementing.

Despite having reached TD while showing no obvious signs of damage (drilling breaks, for example), the dull bit had three broken cutters at the breakover from face profile to gauge. The most likely explanation given is that these cutters were broken while drilling the float equipment. The bit was mathematically modelled with these three cutters removed and the magnitude and direction of the out-of-balance force was found to be substantially unaltered. Therefore the bit would still have been expected to drill as an Antiwhirl bit.

A second bit was run in this area and drilled 1420ft [433m] at 97.9ft/hr [29.8m/hr] to TD through similar formations. The dull bit was graded 1-2-WT-G-X-I-NO-TD. Particularly noticeable were diamond lips formed by erosion of the carbide support for the centre cutters that would have been expected to break off had the bit been whirling.

After minor repair the bit was rerun and drilled a further

2874ft [876m] at 74.6ft/hr [22.7m/hr] for a cumulative 4294ft [1309m] at 81.0ft/hr [24.7m/hr]. Again, no directional problems were reported. The latter run included 500ft [152m] of Basal anhydrite drilled at an exceptional 50.0ft/hr [15.2m/hr]. Table 1 again illustrates the excellent performance of this design in this application.

#### Case History #2 - UK Sector, Central North Sea

An Antiwhirl bit was tested in Cretaceous claystones, marl and limestones<sup>22</sup> and Jurassic Heather formation<sup>23</sup> of the Central North Sea.

The bit drilled a total of 1198ft [365m] in four consecutive runs for an average 51.0ft/hr [15.5m/hr]. The dull was graded 1-1-WT-S-X-CT-CP. It had no problems drilling the base of the Cretaceous and into the Upper Jurassic. Conventional PDC bits have been known to stop drilling in this transition.

The bit was pulled twice for BHA changes due to unexpected directional behaviour. Extreme build and drop tendencies were induced by fairly minor changes to the BHA. After replacement of one twisted cutter and the most heavily worn of the remaining cutters, the bit was run on a close offset well through similar formations but this time it stopped drilling in a limestone stringer, about 10ft [3m] thick, with a sonic transit time less than 40  $\mu$ s/ft. The next bit in hole, a heavy-set PDC bit with 50 cutters, was reported 50% worn after only 100ft [30m].

The Antiwhirl bit made a cumulative 2128ft [649m] at 60.0ft/hr [18.3m/hr]. Table 2 shows that this compares very well with the closest offsets.

#### Case History #3 - U.K. Sector, Northern North Sea

A less successful application of an Antiwhirl bit is described here. Previous wells from this platform had used conventional PDC bits to drill successfully from 9 5/8" casing shoe to TD. This well had a very high inclination angle in the 8 1/2" section and hence the length of the section was extended. The lithology consisted of the Heather formation, followed by the sandstone of the Brent group and finally the Dunlin shales,<sup>23</sup> and it was felt conceivable that the Antiwhirl design could drill this long section in one run.

The bit was run with a near-bit roller reamer, and string roller reamers 16ft [5m] and 55ft [17m] from the bit.

The bit was run in hole to a depth of 16703ft [5091m] (MD). It was not required to drill out the 9 5/8" casing float equipment. The bit drilled the Heather formation at penetration rates of 25.0 to 60.0ft/hr [7.6 to 18.3m/hr]. The bit appeared to have no real difficulty drilling the hard and crystalline limestone stringers in this formation.

A severe reverse drilling break (to 6.0ft/hr [1.8m/hr]) was observed at the top of the Brent group. Traces of pyrite were observed in samples but it is thought unlikely that their size and quantity caused any serious damage to the bit. After this, the bit continued to drill the Brent sandstone at penetration rates of 35.0 to 75.0ft/hr [10.7 to 22.9m/hr] until torque values began to fluctuate and the bit finally stopped drilling after 245ft [75m] of Brent sandstone, 821ft [250m] in total at an average penetration rate of 22.2ft/hr [6.8m/hr]. By this stage the bit body had been worn away to the extent that the fluid courses were closed off and very little useful information could be gleaned from the dull, except that what was left of the bearing pads had only worn by 0.015" [0.381mm].

Disappointment at this performance was tempered when the next bit in hole, a conventional PDC design that was considerably (50%) heavier set, drilled only 474ft [144m] of the same Brent sandstone.

The disappointing performance of the Antiwhirl bit may be explained in one of two ways:

1. It is likely that the bit was simply too light-set to drill the abrasive sandstone, even given the more stable drilling that would be hoped for with an Antiwhirl bit. The failure of the subsequent bit, and high wear (IADC grade 4) of the remaining centre cutters on the dull bear this out.
2. Given the high inclination angle of this hole, it may also be that the side force from the BHA was greater than the critical value described above, despite the relatively large extent of bearing pads and magnitude of out-of-balance force chosen for this design. Such a condition would mean that the bit could no longer resist backwards whirling motion in the way intended.

The first possibility is being addressed by a heavier set Antiwhirl design, with a longer tapered profile to provide room for extra cutters and a deep cone in the centre of the bit to ensure stability. The second is unlikely to be addressed by a modified "lowfriction" Antiwhirl bit design as neither the extent of the bearing pad nor the magnitude of out-of-balance force can practicably be increased. It is likely that bit whirl can only be prevented in situations where a high external side force is anticipated by a different approach either to bit design or to BHA design.

#### Case History #4 - Starr County, Texas

Although the bit used was lost in hole, the directional behaviour observed makes this a noteworthy case history. An Antiwhirl bit was used to drill 1807ft [551m] of Vicksburg sandstone and shale<sup>24</sup> at an average 28.6ft/hr [8.7m/hr]. The

drillpipe became differentially stuck with the bit just 114ft [35m] short of TD, and the bit and drilling assembly were eventually left downhole.

Overall performance was similar to that experienced with a conventional PDC bit, observations of torque while drilling showing no sign of bit whirl.

Single shot drift surveys were taken at approximately 500ft [152m] intervals and showed an increase in inclination from 2° to 6° over the last 380ft [116m]. Prior to this, inclination had held fairly steady. The bit was run on a pendulum assembly, and angle building tendency has been consistently observed with other Antiwhirl bit designs on pendulum assemblies. The section below attempts to explain this, and the sensitivity to BHA configuration of the bit described in case history #2.

### EXPLANATION OF OBSERVED DIRECTIONAL PROPERTIES

Directional behaviour considered unusual was observed on two of the runs described above. Other field runs, with similar designs, have shown similar directional behaviour.

The explanation for this behaviour appears to be twofold.

Firstly, it has been shown<sup>1</sup> that a whirling bit will drill an oversize hole. The Antiwhirl design described above was observed to drill a gauge hole in laboratory tests. If such a bit drills a gauge hole in the field when traditionally bits have drilled oversize holes then the sensitivity of the directional behaviour of the BHA to stabiliser placement may be exaggerated. This was observed in case #2, described above.

Secondly, and perhaps more significantly, an Antiwhirl bit is constrained by its very design not to drill sideways, provided the side force from the BHA is less than a critical value (see above), and provided this condition is met it will drill in the direction in which it points. In other words, it is totally anisotropic.<sup>25</sup> Figure 6 shows a typical pendulum assembly.<sup>26</sup> The assembly relies on the bit side force inducing side cutting to overcome the building tendency imparted by the bit tilt and hence drop angle. Having no side cutting ability an Antiwhirl bit will build angle on a pendulum assembly, just as observed in case #4 above.

Thus the directional behaviour of an Antiwhirl bit can be different to that of a more conventional PDC bit. However, hole size drilled and bit side cutting ability are regarded as two of the largest unknowns when attempting to analyze the behaviour of a BHA. By drilling a more gauge hole and by inhibiting side-cutting ability the Antiwhirl bit effectively removes these two unknowns. The behaviour of such a bit may also be less dependent on a third unknown, the formation anisotropy index, and its orientation. Although

the directional behaviour of an Antiwhirl bit on a given BHA may be different to that of a conventional PDC bit, it is also likely to be more predictable. However, optimum performance may be achieved by a new approach to BHA design, in applications where an effectively isotropic bit (roller cone bit) is to be replaced by a totally anisotropic one.

### CONCLUSIONS

1. There is a limit to the external side force that a "low-friction" Antiwhirl bit can tolerate. This limit increases with the angular extent of the bearing pads and with the magnitude of the out-of-balance force arising from the cutters on the bit.
2. When operating with an external side force below that critical limit, an Antiwhirl bit has been observed to drill with no evidence of bit whirl during laboratory testing. In a controlled field test the bit has outperformed, in terms of life and resistance to cutter damage, a more conventional design on which it was based.
3. In uncontrolled field tests, the penetration rate observed with Antiwhirl bits has consistently been as high as or higher than the fastest conventional PDC offsets, implying that the Antiwhirl bits are drilling in a more efficient manner.
4. In uncontrolled field tests, dull condition of Antiwhirl bits after drilling a range of formations including hard limestones and dolomites has been encouraging. Dull condition after drilling more abrasive formations has been disappointing and has identified a requirement for a more abrasion-resistant design.
5. An Antiwhirl bit is effectively anisotropic, in other words, such a bit lacks side-cutting capability (subject to the external side force being below the critical limit described above). Uncontrolled field test results have shown directional behaviour that confirms this.
6. The directional behaviour of an Antiwhirl bit on a given BHA may be different from that of a more conventional design, but given an understanding of the effects at work it will be more predictable.
7. BHA design for an Antiwhirl bit should minimise side force and must ensure that it does not exceed the critical limit described above. For applications where this is impractical, another approach to bit design for stability may be required.

## NOMENCLATURE

$A$	=	Hole area
$F_{BHA}$	=	Side force imposed by BHA
$F_I$	=	Out-of-balance force
$F_R$	=	Resultant side force
$K$	=	Constant of proportionality
$N$	=	Rotary speed
$R$	=	Rate of penetration
$SE$	=	Specific energy
$T$	=	Torque
$W$	=	Weight on bit
$\alpha$	=	Minimum angle subtended by bearing pads on an Antiwhirl bit

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## PATENTS

The following patents are relevant to the design of the bit discussed in this paper: US Patents 4640375, 4676324, 4718505, 5010789, 5042596; British 2161849, 2175939; European 0169683, 0384734; Others are pending. Corresponding patents or patent applications are also granted or filed in other countries.

**Table 1 - Offset Performance, Case History #1**

	No. of Bits	Average life (ft)	Average ROP (ft/hr)
Antiwhirl bit # 1	1	2870	82.5
Antiwhirl bit # 2, run # 1	1	1420	97.9
Antiwhirl bit # 2, run # 2	1	2874	74.6
Antiwhirl bit # 2, cumulative	1	4294	81.0
8½" offsets	47	1929	42.0
12¼" offsets	5	2276	70.2

**Table 2 - Offset Performance, Case History #2**

	No of Bits	Average life (ft)	Average ROP (ft/hr)
Antiwhirl bit, run # 1	1	1198	51.0
Antiwhirl bit, run # 2	1	930	77.0
Antiwhirl bit, cumulative	1	2128	60.0
8½" offset	1	1894	43.0
12¼" offset	5	1622	34.9

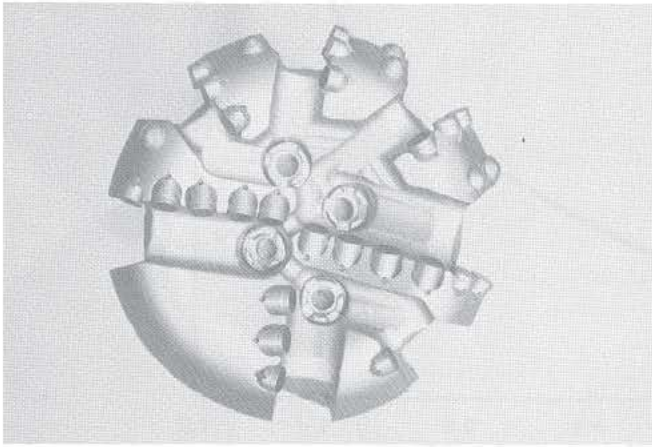


Fig. 1—Antiwhirl PDC bit, end view.

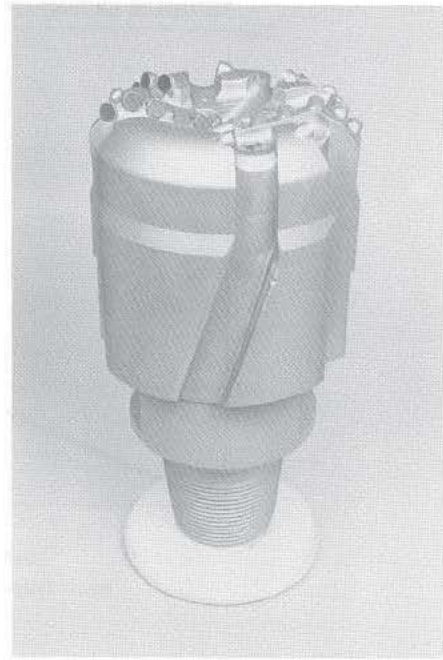


Fig. 2—Antiwhirl PDC bit, bearing pads.

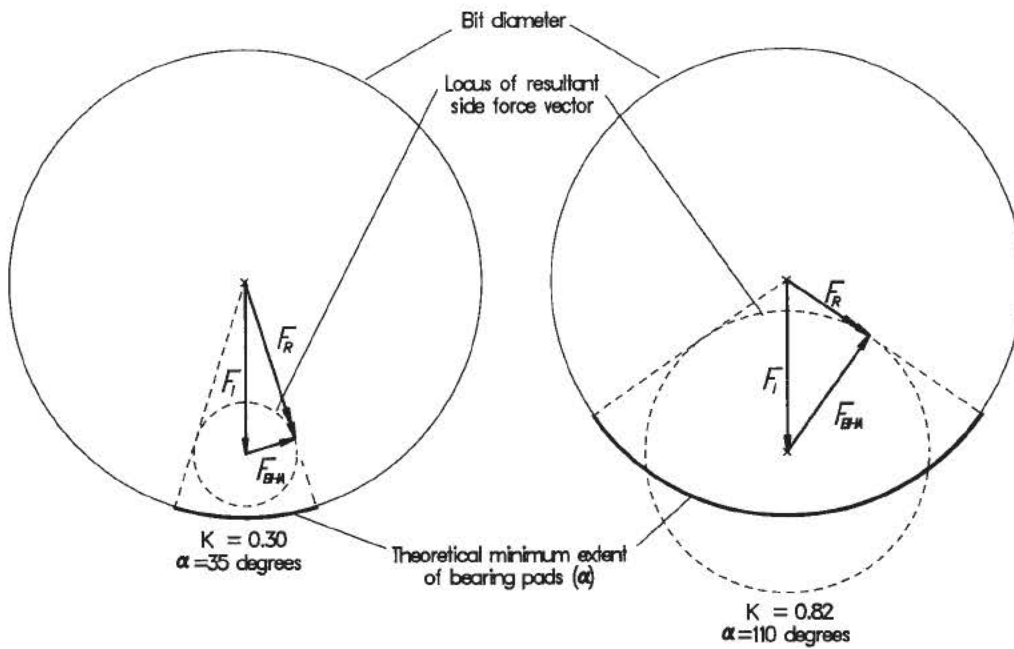


Fig. 3—Theoretical minimum extent of bearing pads.

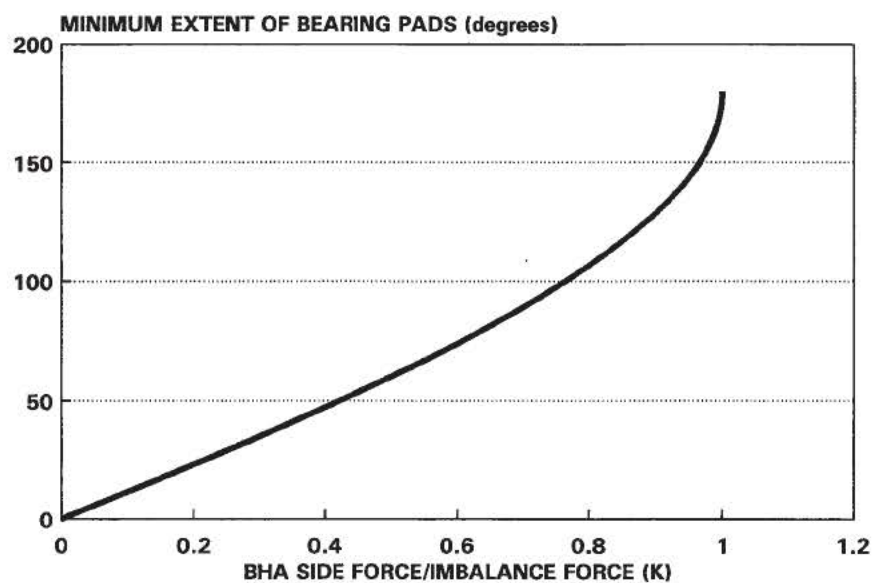


Fig. 4—Minimum extent of bearing pads as a function of BHA side force.

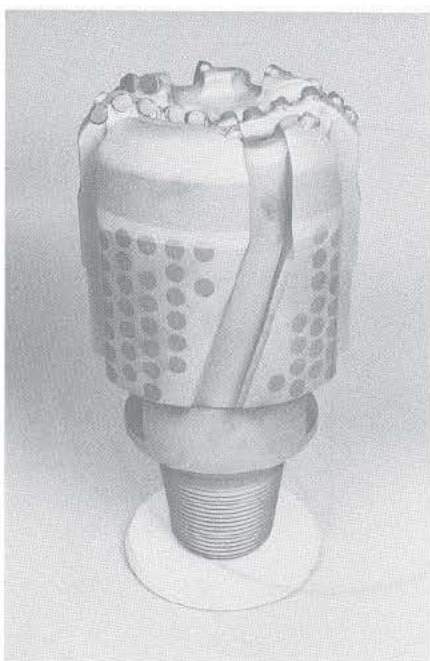


Fig. 5—Antiwhirl PDC bit after controlled field test.

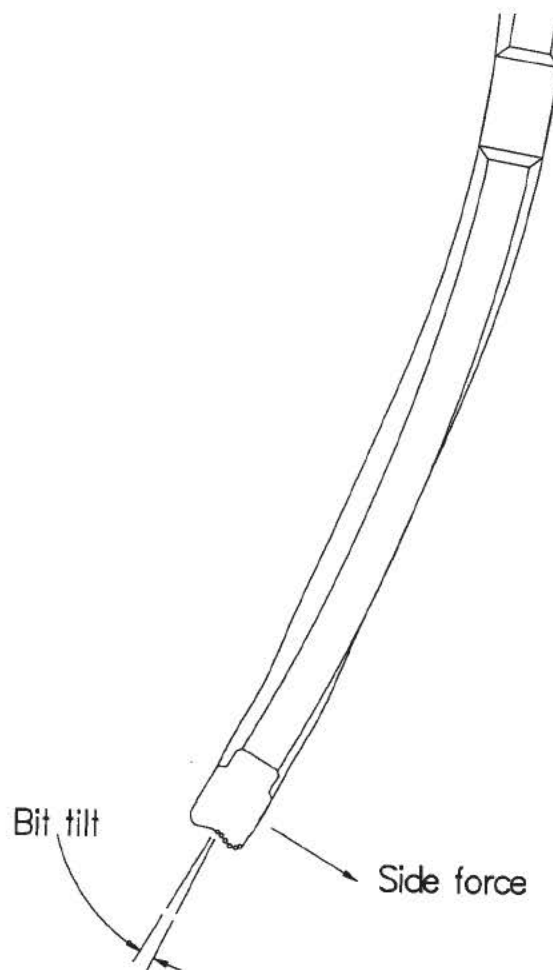


Fig. 6—Typical pendulum assembly.