

# Lateral-Jet Hydraulics and Oval-Cutter Technology Combine To Improve PDC Performance, North Sea Scott Field

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## Summary

The successful implementation of lateral-jet polycrystalline diamond cutter (PDC) hydraulics has emerged over the last few years with quantifiable results. Lateral jets set into the blades of the bit improve the cutter cleaning efficiency, thereby increasing the rate of production (ROP). In addition to cleaning the plenum in front of the jet, fluid entrainment creates a Venturi effect, drawing the fluid across the blades serviced by the downward jets. This flow is then ejected at high speed to the junk slots.

The operators of the North Sea Scott field took a major initiative in this development, and in conjunction with the lateral-jet company, expanded the technology to initiate a new cutter design and the second generation of lateral-jet-type bits, the fully lateral-jet PDC drill bit.

This paper will track the development of the technology from the initial trials of lateral jets in the Scott field, the rationale and design criteria that initiated oval PDC cutters, and most recently the fully lateral-jet bit.

## Introduction to Scott Field

The Scott field straddles Blocks 15/21 and 15/22 and is one of the largest fields to come onstream in the United Kingdom Central North Sea Sector in recent years (Fig 1).

The first well drilled on the crest of the Scott structure was 15/22-3, drilled in 1977. This well encountered no sands of reservoir quality, and it was not until 1983 that Well 15/22-4 encountered oil-bearing sands in what are now known as the Scott (C) sands of Block 1a. A follow-up downdip appraisal well, 15/22-5, was a dry hole and estimates of the size of the accumulation were downgraded.

It was not until the drilling of Well 15/21a-15 in 1987 that the potential size of the accumulation became apparent. Rapid appraisal of the Waverly prospect (as it was known by the 15/21 group) and the Brunel prospect (as it was known by the 15/22 group) continued through to 1989, leading to Annex B approval in 1990 for the newly named Scott field.

To achieve a rapid buildup to plateau production, seven subsea production wells and seven associated water-injection wells were drilled and completed before first oil. Drilling has continued with a program of production wells being drilled from the production platform. The subsea wells have been drilled from four different locations which, in conjunction with the platform, give five separate surface clusters of wells (Fig 2).

**Lithology and Typical Well Design.** The lithology is similar to many neighboring fields, with oil being produced from Jurassic sands. All directional work is completed in the 16-in. hole section before setting 13<sup>3</sup>/<sub>8</sub>-in. casing in Paleocene shales. A 12<sup>1</sup>/<sub>4</sub>-in. tangent section is then drilled through the lower Paleocene and Cretaceous, with 9<sup>5</sup>/<sub>8</sub>-in. casing being set before the top of the Kimmeridge clay formation. An 8<sup>1</sup>/<sub>2</sub>-in. section is then drilled to total depth (TD). Less toxic oil-based mud is used from below the 20-in. casing shoe until TD (Fig 3).

**Established Drilling Practice in 12<sup>1</sup>/<sub>4</sub>-in. Hole.** Considerable drilling has taken place in the immediate vicinity of Scott. Block 15/21 contains the producing Ivanhoe, Rob Roy, and Hamish fields, and had seen some 40 wells drilled before the commencement of development drilling on Scott. A large amount of offset information was therefore available and considerable work had already been done to optimize bit selection and establish the suitability of PDC bits for the various formations.

Much of the Paleocene encountered in the 12<sup>1</sup>/<sub>4</sub>-in. section is easily drilled with a roller-cone steel-tooth rock bit; however, the Ekofisk chalk formation at the base of the Paleocene is extremely hard and is usually drilled with an insert bit. Once clean chalk of the Cretaceous Tor formation has been encountered, this bit is pulled and a PDC bit run. This drills all the Cretaceous chalk down to the Herring formation, where it is pulled. The Herring formation is very hard and may contain chert. The Herring is drilled with insert bits before picking up a PDC bit to drill the remainder of the chalk and lower Cretaceous to casing point (Fig 4).

The two most important aspects that have been identified for successful PDC application are the hardness and thickness of the Ekofisk (to ensure that the PDC bit is not run too early), and the thickness and hardness of the Herring and the presence or not of chert.

On the Scott field the chalk sequence varies in its characteristics across the field; as a generalization the chalk is more uniform and chert-free in the east and softer with chert in the west. This is an important point with implications for the PDC-run potential from the different surface locations.

## Introduction to Lateral-Jet Technology

Lewis *et al.*<sup>1</sup> discuss the major physical differences between lateral-jet PDC hydraulic activity and conventional PDC hydraulic activity. That paper gave an insight into the investment-casting process, chosen for the manufacture of lateral-jet products because of the complex nature of the internal fluid paths and dimensional accuracy, and the utilization of super alloy bit-body material over conventional tungsten carbide matrix or steel.

Basic principles of lateral-jet hydraulics were also discussed. The lateral-jet bit's most noticeable feature is the inclusion of two central lateral jets, in addition to the two or four downward nozzles. The jets are set opposite each other in the crown, and direct a portion of the drilling fluid laterally across the debris slots. In addition to cleaning the slot in front of it, the hydraulic medium is drawn across the blades serviced by the downward jets through fluid entrainment. This enhances cutter cleaning and cooling, and cuttings removal (Fig 5).

The importance of PDC hydraulics in relation to ROP and cutter cooling and cleaning has been the focus of many technical papers.

King *et al.*<sup>5</sup> observed that hydraulic optimization has an important part to play in the improvement of drill-bit performance.

White *et al.*<sup>4</sup> combined the observations of McClean<sup>6</sup>, Glowka<sup>7</sup>, and Cholet and Crausse<sup>8</sup> when he suggested that there have been very few visualization studies of the flow beneath a bit. McClean sketched some flow lines inferred from measured crossflow velocities, while Glowka used dye injection to study the flow pattern from the nozzle in a PDC bit, but concluded that the utility of such a technique was low. Cholet and Crausse used neutrally buoyant beads, which were tracked photographically and the results projected onto a horizontal plane.

Finally Cruz<sup>2,3</sup> determined that the flow pattern in a wing-type bit appeared to be very complex; that the flow area through the different



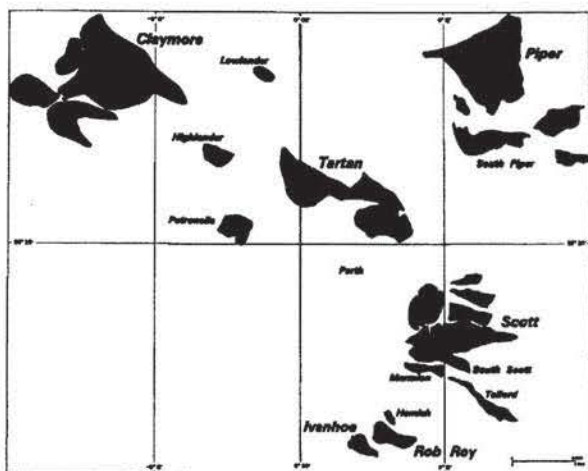


Fig. 1—Location of Scott field.

wings of the bit are not reliable indicators of the velocity distributions; and that the hydraulic design of a PDC bit is one of the most critical factors that affects its drill performance.

In June 1991, within the Scott field in the U.K. sector of the North Sea, the initial benefits of lateral-jet hydraulics on ROP were experienced using six-bladed lateral-jet-type bits set with conventional 13 mm round PDC cutters. ROP on these initial runs was seen to increase by between 20 and 22%, and as a result (as with most drill-bit development programs) as one performance parameter was extended and improved, another became the focus of attention. In this study, extending bit life through the diverse formation types that are found within the 12¼-in. hole section became the focus.

**Early Field Results.** By the commencement of development drilling, earlier drilling experience had shown that the fastest penetration through the chalk was being achieved with a conventional down-jet hydraulics steel-bodied 13 mm cutter-type bit Intl. Assn. of Drilling Contractors (IADC) S646 (for the purpose of this paper designated Type 1 in Table 1). This bit type achieved ROP's of 33 and 36 ft/hr on the first wells on the A manifold, and ROP's of 23, 26, and 25 ft/hr on the C manifold.

A side track was then drilled at both manifolds, offering an ideal comparison with established performance. On C2Z the lateral bit (designated Type 2) achieved 30 ft/hr, a 15% increase over the best achieved on that manifold, and a 22% increase over the original well.

Similarly, on A1Z the lateral bit achieved 41 ft/hr, a 14% increase over the best achieved on that manifold, and a 21% increase over the original well.

Given the overall similarity of the bits in cutter size, density, and bit profile, it is difficult to avoid the conclusion that the obvious improvement in ROP is because of the different hydraulics and nozzle configuration (Figs. 6 through 8).

As a result of these successes, the lateral-jet bit became the standard PDC bit for drilling the chalk.

### Potential for Longer Runs

All the runs featured are tangent sections of directional wells and pulling of the BHA for directional purposes was an inevitable interruption of many of the early bit runs. However, as knowledge of the directional characteristics of the field increased, trips for directional reasons became less frequent. This meant that in many cases the run length could be dictated by longevity of the bit.

There were two good reasons why increased PDC-bit longevity could be extremely beneficial.

- In the east of the field, where chalk is more consistent and there is no chert in the Herring, there was good reason to believe that one bit could conceivably drill the entire section from base Ekofisk to interval TD.
- In the west of the field, the preceding rock bit may fail before clean chalk of the Tor formation was encountered. If the PDC bit had sufficient longevity to drill the remainder of the Ekofisk and still last to the Herring, a further rock-bit run in the Ekofisk could be avoided.

This analysis coincided with the research work being carried out by the lateral-jet-bit company, and the oval cutter was seen as a viable possibility. The design of the bit initially utilized maintained identical profile, cutter count, and hydraulics configuration as the conventional 13 mm round cutter lateral-jet bit. Thus the only difference on bit design between Type 2 and Type 3 was the change from 13 mm round to 19 mm × 13 mm oval cutters (Fig. 4).

### Introduction of Oval Cutters

It had been known for some time that the investment-casting process would lend itself to the introduction of shaped-cutter installation pockets other than circular or round. In this knowledge, technical staff from the bit company had put forward a number of suggestions for consideration, such as dovetailed pockets or pockets to accommodate other keyed attachment mechanisms. While the ideas were technically feasible, none was pursued because of the lack of perceived benefit in performance enhancement or manufacturing-cost reduction.

The suggestion was then put forward for an oval-shaped cutter, which could be easily introduced in the current manufacturing process. The Design Engineering Dept. felt this idea worthy of further investigation, and gave careful consideration to the additional implications of introducing a new shaped cutter, and quickly became aware of certain design benefits including the following.

**Improved Cutter Attachment.** It was realized that attachment of this shaped cutter to the bit would be more substantial than for the

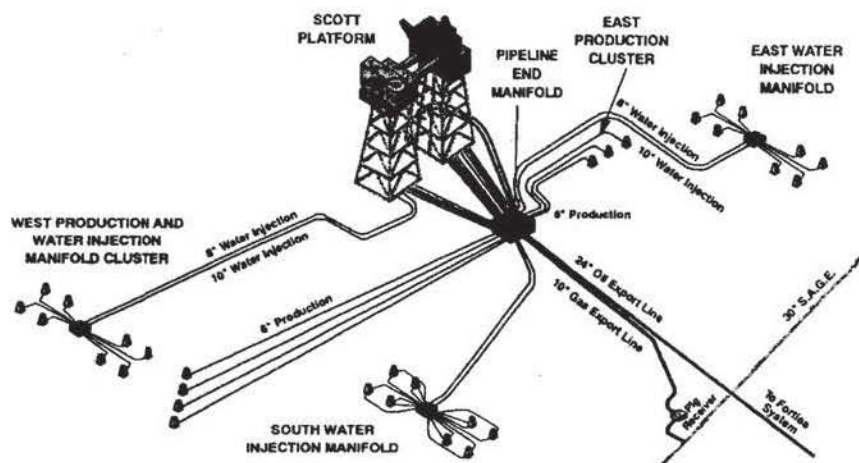


Fig. 2—Scott development field layout.

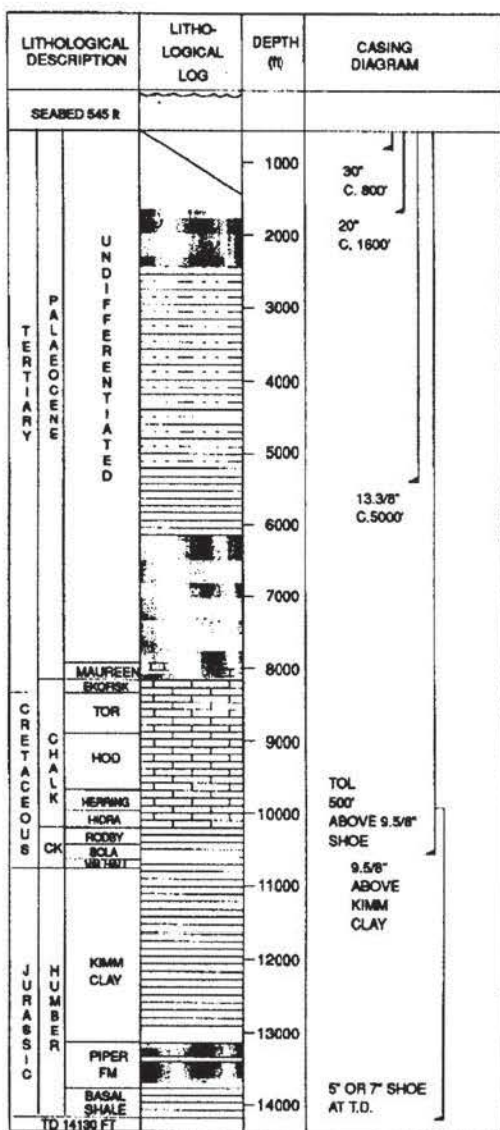


Fig. 3—Typical Scott well profile.

previous circular cutter, made possible by the increased cutter stand off and the increased area of the braze contract.

**Increased Cutter Density.** Not only was the cutter exposure increased, but when compared to PDC bits with equivalent stand off (i.e. 19 mm round cutters), the oval cutters allowed a higher cutter-setting density. This was because of better nesting of set cutters, especially on the shoulder areas of the bit. A 19 mm × 13 mm oval cutter gives the exposure of a 19 mm conventional round with the packing density of a 13 mm conventional round.

**Product Development.** This new shape of cutter was introduced in the existing design and manufacture of product. The development work was taking place at the same period of time that the first runs were being successfully applied to the Scott field using conventional 13 mm round 1308 PDC-type cutters. Because the first oval cutters were chosen to be 13 mm × 19 mm aspect ratio, it was possible to redesign the successful bits then in use on the Scott field to accommodate the new oval material without reducing cutter density. Other beneficial factors, in addition to the increased cutter density and improved attachment already mentioned, became self-evident.

**Increased Usable PDC.** The increased cutter stand off with the same cutter density as previous bits effectively increased the usable PDC in the bit by 25%. This improvement can be seen from field data

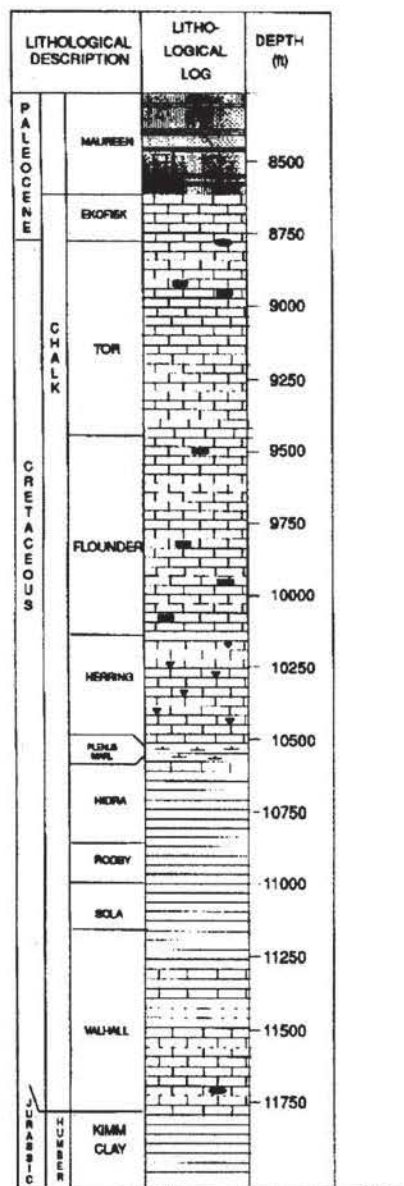


Fig. 4—Typical Scott chalk section.

where the new style of bit using oval cutters increased the run length in terms of footage drilled, while maintaining ROP performance.

**Increased Footage Drilled.** While the 19 mm × 13 mm oval cutter offered a potential of 25% extra diamond, in the field the increased footage gained by the use of oval cutters in most cases exceeded 25%. In some runs the footage drilled was as much as double that of the original bit runs that had used 13 mm round cutters. This could not be entirely attributed to the increase in usable diamond; other factors had to be taken into consideration, such as the formation, which was known to be softer in the lower sections of the hole, and/or the PDC performance, which could have improved.

**Increase in PDC Performance.** One area which could have been providing additional benefit in PDC performance was the rate at which the wear flat was generated on an oval cutter when compared with a round cutter of equivalent diameter and width. The oval cutter wear flat for a given depth of diamond wear is less than that for a round cutter.

**Wear-Flat Generation and Effect.** The rate of wear-flat generation will have a significant effect on the performance of PDC's because increase in wear-flat area produces a larger area of the cutter subject



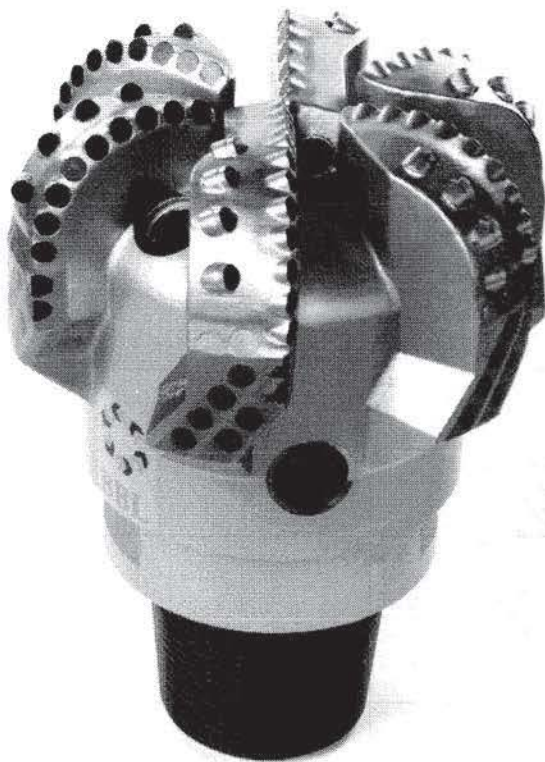


Fig. 5—Lateral-jet bit.

to loading. This increased area would effectively increase the operating temperature of the cutter in two ways. It would require greater loading for equivalent cutter penetration, increasing friction and therefore temperature; and it would exclude the effect of cooling and lubrication of the drilling mud, further exacerbating the above factor.

Glowka and Stone<sup>9</sup> deduced that "Experimental data with hard abrasive Sandstone shows that PDC cutter wear rate increases one to two orders of magnitude when the cutter wear-flat temperature exceeds a critical value of approximately 350°C (660°F)." Wear-flat temperature is controlled by weight on bit and rotary speed for a given environment and these two variables are also the primary factors which influence ROP and bit life.

As bit wear occurs, increased weight on bit is required to maintain ROP, but the result of doing so is to increase wear-flat temperature, further reducing bit life. Cutters that generate a lower rate of wear-flat increase, for given diamond table wear, must therefore provide a benefit with respect to reduced cutter temperature and, correspondingly, an increase in bit life. This may in part explain the performance benefit that was found by using oval-cutter bits in the Scott field.

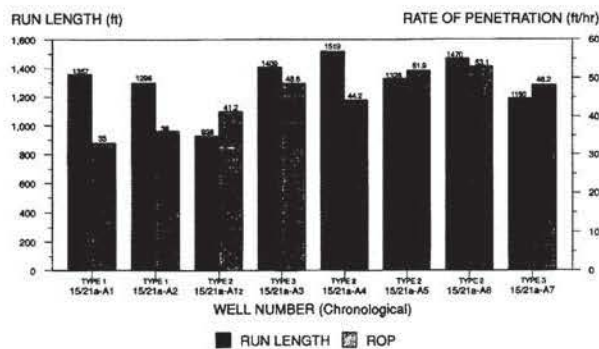


Fig. 6—Bit-run performance on A manifold.

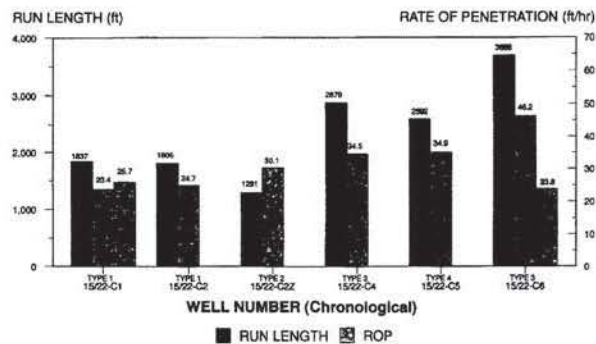


Fig. 7—Bit-run performance on C manifold.

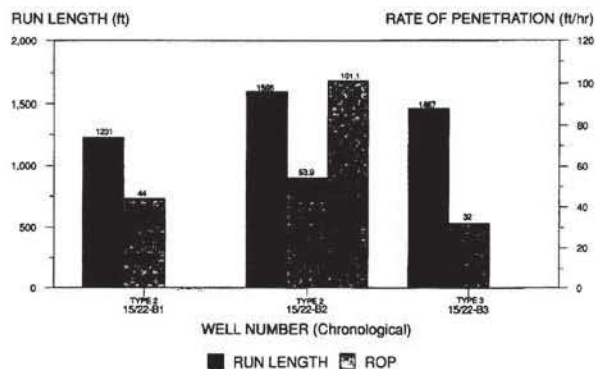


Fig. 8—Bit-run performance on B manifold.

**Diamond Thermal Conductivity.** The conductivity of the PDC diamond is over four times greater than that of tungsten carbide and nearly 10 times that of steel (Table 2).

A PDC diamond table will conduct heat away from the wear-flat area far more efficiently than the carbide substrate. Mud passing over the face of the PDC cutter will cool the diamond table of the

TABLE 1—BIT TYPES USED IN THIS STUDY

	Body Material	Profile	Main Cutter Size	Density	Hydraulics	IADC Code
Type 1	steel	eight-blade rounded concave	round 13 mm	heavy set	four downjet	S646
Type 2	high cobalt alloy	six-blade medium taper	round 13 mm	heavy set	two lateral four downjet	O619
Type 3	high cobalt alloy	six-blade medium taper	oval 19x13 mm	heavy set	two lateral four downjet	O619
Type 4	matrix	six-blade medium taper	round 13 mm+ hybrid backup	heavy set	six downjet	M332
Type 5	high cobalt alloy	six-blade medium taper	oval 19x13 mm	heavy set	six lateral two downjet	O619
Type 6	matrix	seven-blade medium taper	round 13 mm+ hybrid backup	heavy set	five downjet	M432

TABLE 2—RELATIVE THERMAL CONDUCTIVITY	
Material	Thermal Conductivity (BTU/ft <sup>2</sup> hr°F)
polycrystalline diamond	260
tungsten carbide	57
steel	27
matrix	8

cutter, carrying away this conducted heat. The ability of the mud to carry out this function effectively depends upon the area of polycrystalline diamond with which it has contact.

If the fact that wear-flat generation on a round cutter develops faster than on an oval cutter is considered, then the fact that the oval cutter exposes considerably more diamond to the cooling effect of the mud should also be taken into account. If these two factors were taken into consideration, then the effect of round cutters vs. oval on operating temperature would be very significant (Fig. 9).

Given that the equation of ellipse is

$$\frac{x^2}{a^2} + \frac{y^2}{b^2} = 1 \dots\dots\dots (1)$$

and the area of hatch is

$$A_{pq} = \frac{b}{a} \int_p^q (a^2 - x^2)^{1/2} dx = \frac{b}{a} \left[ \frac{x}{2} (a^2 - x^2)^{1/2} + \frac{a^2}{2} \sin^{-1} \frac{x}{a} \right]_p^q \dots\dots\dots (2)$$

then the total area of the interval between  $p$  and  $q$  is

$$\frac{b}{a} \left\{ \left[ q(a^2 - q^2)^{1/2} + a^2 \sin^{-1} \frac{q}{a} \right] - \left[ p(a^2 - p^2)^{1/2} + a^2 \sin^{-1} \frac{p}{a} \right] \right\} \dots\dots\dots (3)$$

This is also true for a circle, in which case  $b = a$ . Referring to Fig. 10, the area of diamond remaining after a wear of  $d$  mm has taken place is calculated by substituting  $p = -a$  and  $q = a - d$  in the above equation. Similarly, the wear-flat area can be calculated, allowing for cutter back-rake angle.

In Fig. 10,  $R_c$  is defined as the ratio of wear-flat area ( $A_{cw}$ ) to diamond area remaining ( $A_{cl}$ ). Thus, a low value of  $R_c$  would result from a small wear flat and little wear. The higher the value of  $R_c$ , the more likely the cutter is to suffer increased wear rate because of increased temperature.

In reference to Fig. 11,  $R_c$  is the ratio for a 13 mm diameter circular cutter and  $R_o$  is that for a 19 mm × 13 mm elliptical cutter. The ratio  $R_c/R_o$  is a measure of the increased ability of an elliptical cutter to shed heat, compared to a circular cutter.

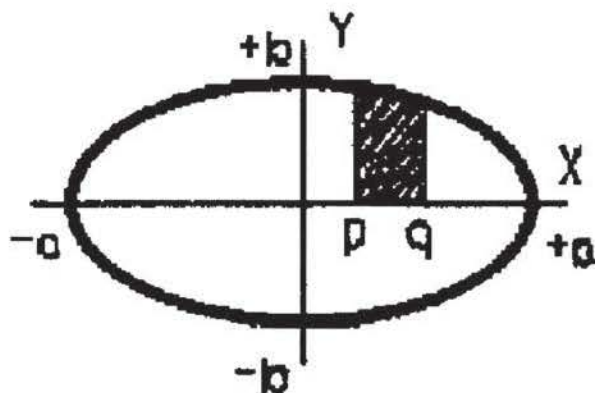


Fig. 9—Graph of ellipse.

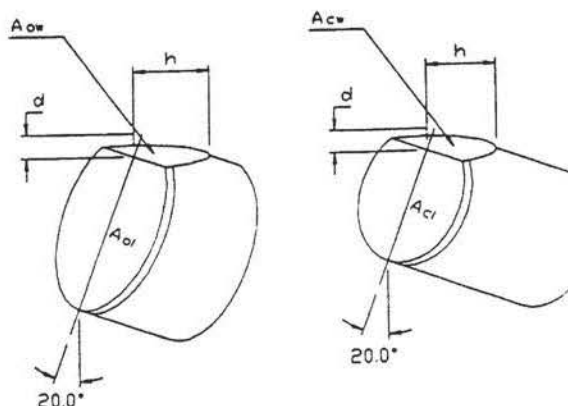


Fig. 10—Nomenclature for oval- and round-cutter wear flats.

### Results of Oval-Cutter Trials

The oval-cutter bit (Fig. 12) proved to be highly successful on the C manifold in the east. A run length of 2,879 ft was achieved with ROP's as good or better than those already achieved at that manifold. For the first time it had been possible to drill from base Ekofisk to interval TD in one run (Fig. 7).

This success was repeated on the D manifold, where a lateral-jet bit with oval cutters drilled the entire section on Well D3, achieving 2,410 ft at ROP's of 34 to 27 ft/hr (Fig. 13).

In the west the lateral-jet oval cutter bits were deployed on a back-up basis. If the preceding rock bit had penetrated clean Tor, then a lateral-jet 13 mm round cutter bit could be used. If it was found that some of the Ekofisk remained undrilled, then an oval cutter would be used to ensure that the entire section to top Herring was drilled.

**Continued Comparison With Alternative Bits.** For an operating company in development situations such as these, a balance must be struck between further development of a successful product and continuous monitoring of available alternatives.

Following the establishment of the oval cutter bit as the new benchmark PDC bit for the field, two comparisons were made with alternative bits.

On C5 a six-bladed matrix body PDC bit with 13-mm round cutters and impregnated diamond backups and six conventional down-jet nozzles (Type 4) drilled the section to TD. The Ekofisk and Tor had already been drilled with a lateral-jet bit and yet the Type 4 still only achieved the same overall ROP as oval-cutter lateral-jet bits, which had drilled the entire section. Normally the ROP starts off slowly before building up later on in the section. There is little doubt

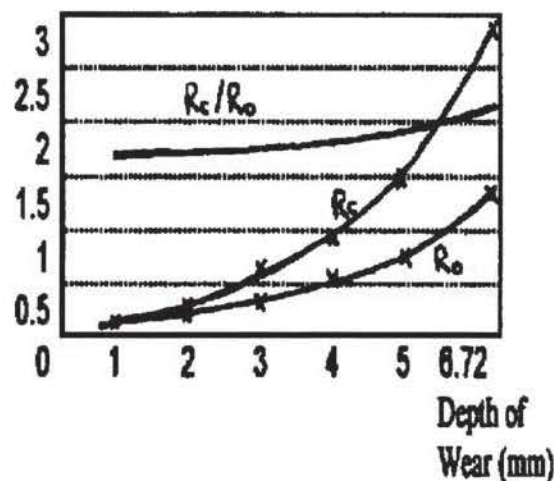


Fig. 11—Results of oval-cutter trials.



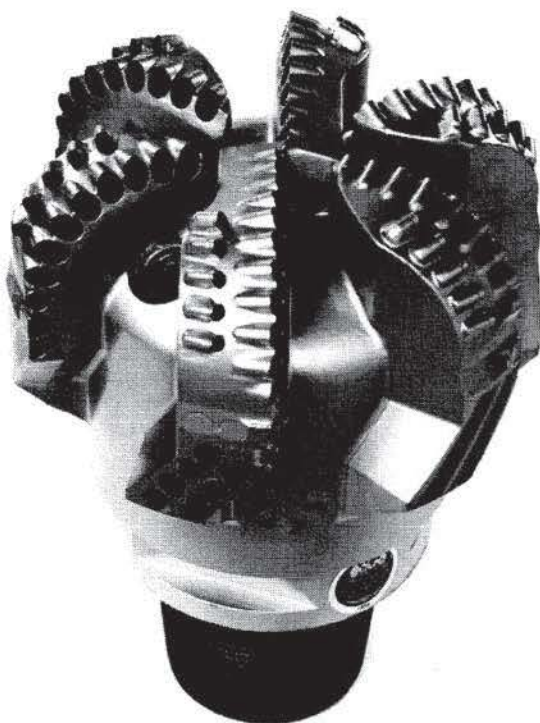


Fig. 12—Lateral-jet bit with oval cutters.

that had this bit gone in at the same point as the oval-cutter bits, the overall ROP would have been significantly reduced (Fig 7).

On D4 a Type 6 (Table 1) conventional hydraulic design of PDC bit was run. This bit equaled the ROP achieved by the lateral-jet oval-cutter bit run on D3, but failed to drill the entire section. A follow-up run was required to reach interval TD.

**Future Lateral-Jet Development.** The benefits of lateral-jet bits in the Scott field encouraged the operating company and the lateral-jet bit manufacturer to explore the concept of lateral jetting still further.

The current production bits used on Scott, as discussed earlier, use the concept of two lateral jets combined with four conventional downward-facing jets.

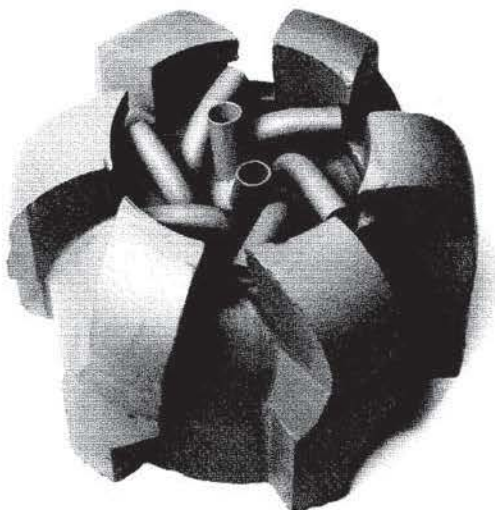


Fig. 14—Experimental fully lateral bit.

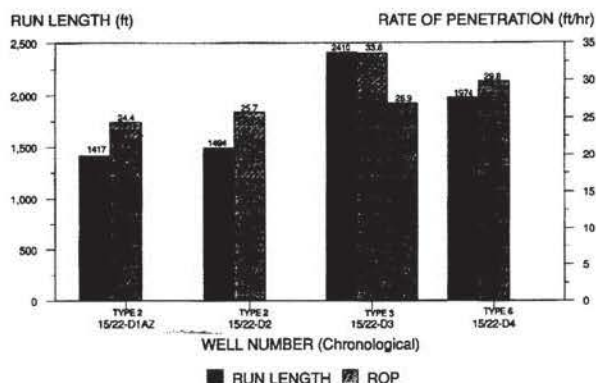


Fig. 13—Bit-run performance on D manifold.

Considerable study was applied to other configurations of lateral jets that could provide further benefits in terms of cutter cooling and hole cleaning, improving upon the performances achieved so far. One such configuration was the development of a fully lateral-jetted bits.

#### Experimental Fully Lateral-Jet-Bit Rationale

The entrainment effect of the jet of fluid as mentioned earlier, is the fact that a high-velocity jet is surrounded by a low pressure, causing fluid and debris from the cutting face to be drawn into the jet stream.

The logic of the fully lateral-jetted bit is to use this entrainment effect of the lateral jets to not only scavenge the bottom of the hole of cuttings debris, but also to create a zone of low pressure at the bit center. This low-pressure zone would locally reduce the effect of overbalance created by the hydrostatic pressure of the drilling mud, and thereby increase the ROP potential of the bit. The lateral-jet company has at its disposal a fluid-flow test bed and was able to examine this hypothesis on full-scale models of the experimental bit.

To achieve the above, an array of six lateral jets was set in the bit crown, all configured to fire outwards towards their respective junk slots and past the cutting structure on each blade to provide cooling and cleaning for the respective cutters.

**Manufacturing Process of Multilateral Bit.** It was mentioned earlier that the use of investment-casting methods provides a designer with the freedom to develop new approaches to hydraulics, such as the two lateral jets used in the current design of bits on Scott.

When considering the new development area of multilateral bits, the choice of manufacturing technique becomes even more crucial, as the complex internal flow paths of this bit style (Fig. 14) clearly demonstrate.

**Fully Lateral Bits.** Two runs have been completed to date with the fully lateral bit (Type 5), both from the production platform (jacket). The first run increased the ROP to 45 ft/hr from the 27 ft/hr in the previous two runs, and drilled the entire section from below the Ekofisk to TD. The second fully lateral bit failed to make the entire interval

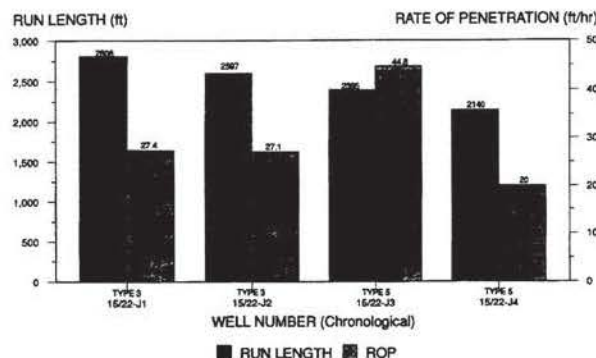


Fig. 15—Bit-run performance on J manifold.

and drilled at only 20 ft/hr. It is too early to speculate on the significance of these runs (**Fig. 15**) from a field performance perspective.

## Conclusions

The authors conclude that lateral-jet hydraulics and oval-cutter technology have improved performance in the North Sea Scott field.

The enhanced ROP is primarily attributable to improved hydraulic efficiency. The increase in footage achievable is a combination of increased diamond availability and the ability to sustain diamond sharpness and durability because of more efficient heat dissipation by the cutter itself. At this time performance with the fully lateral-jet product is unquantifiable, but the technology merits further investigation and development.

## Nomenclature

- $a$  = ellipse half major axis
- $b$  = ellipse half minor axis
- $d$  = depth of wear
- $h$  = wear flat length
- $p$  = wear limit
- $q$  = wear limit
- $x$  = x-axis
- $y$  = y-axis

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## SI Metric Conversion Factors

$$\begin{array}{ll} \text{ft} \times 3.048^* & \text{E}-01 = \text{m} \\ \text{in.} \times 2.54^* & \text{E}+00 = \text{cm} \end{array}$$

\*Conversion factor is exact.

SPEDC

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