SPE 50675

Drilling of an intermediate radius long lateral in the Dunbar field

Ph. A. Charlez, SPE and M. Ryan, SPE — Total Oil Marine
G. Brandie — Baker Hughes INTEQ

This paper was prepared for presentation at the 1998 SPE European Petroleum Conference held in The Hague, The Netherlands, 20–22 October 1998.

Abstract

This paper describes the drilling of an intermediate radius, long lateral side-track drain in the Dunbar field (Central Graben - North Sea) initiated from a low inclination (32.3°) parent hole which had been drilled four years earlier. The main goal was to constrain the drain within the upper part of the UMS formation (Upper Massive Sand - Brent reservoir) over a distance of 1000m from the parent hole. The kick-off (51°/30m DLS) was successfully achieved in two runs and 48 hours using a short titanium downhole motor with a 3° adjustable kick-off (AKO) setting. Thereafter, 910m of horizontal drain were drilled in 4 runs (10 days) with an intermediate length motor (6 meters) and PDC bits making a total lateral length of 1000m. Actual torque and drag remained satisfactory and close to those predicted by drill-string models. The major part of the drain was drilled in rotary mode (only minor azimuth corrections in sliding mode were necessary). The lateral was logged (gamma, sonic and resistivity) in TLC mode. Finally, and according to the results of an advanced wellbore stability study (no sand production expected) the drain was kept open hole and the parent hole completed with a monobore 4 1/2" tubing.

D05z lateral is the first extremely long lateral drilled in the North Sea after such a dog-leg. The combination of high DLS (up to 51°/30m), TVD (3570m) and length (1000m) marks it as one of the most challenging wells drilled in the North Sea.

Introduction

The Dunbar field[1,2] is located in the northern part of the North Sea (Viking Graben - **Fig. 1a**). It is operated by Total Oil Marine plc (33.3%) with partner Elf Exploration UK plc (66.6%). The three main targets (below 3500mTVD) are in the middle and bottom Jurassic (respectively Brent and Statfjord reservoirs) and in the Triassic (Lunde reservoir). Depending on the location they can be oil bearing, gas bearing or both. The Brent reservoir is divided into several layers, the top of which is called UMS (Upper Massive Sands). The UMS itself is not homogeneous, its base being much more permeable than its top.

Typical well design, mud weight strategy, and leak-off test values are presented in **Fig. 1b**. After batch setting a conductor pipe (26") 80 meters below the sea bed (140 m water depth), drilling is initiated in 23 1/2" with a 1.08SG water base mud. The 18 5/8" casing shoe (LOT in the range of 1.30SG to 1.35SG) is set at the bottom of these recent (mainly sandy) sediments. The 17 1/2" phase (Oligocene, Eocene and Palaeocene) is resumed with a water base mud 1.10SG in the Oligocene then raised to 1.22SG just before reaching the Eocene. Depending on the well profile, deviation at the 13 3/8" casing (set in the top Cretaceous) is classically between 20° and 45°. A minimum LOT of 1.70SG is required before initiating the 12 1/4" phase. The latter is drilled with a synthetic oil based mud in the range of 1.50SG to 1.55SG. The 9 5/8" is generally set just above the reservoir section in the Kimmeridge clay (top Jurassic) where a very high LOT value (up to 2.15SG) is obtained. In case of ERD wells, inclination sometimes goes up to 70° at the 9 5/8" casing shoe and, to ensure stability of the Kimmeridge, the mud weight has to be raised up to 1.70SG. Finally, the reservoirs are drilled in 8 1/2" diameter and covered with a 4 1/2" cemented liner providing full bore access from the 4 1/2" tubing.

Parent hole D05

Well D05 had been drilled during the pre-drilling campaign (July and August 1993) and was tied back to the Dunbar platform which was installed afterwards. Roughly speaking, D05 is a classical J-shape well (**Fig. 2a**) with a kick-off starting at 1000mTVDBRT. The maximum inclination (37°) is reached at 2380mMDBRT (2224.3mTVDBRT). After a slight drop off to 28.5° at 3440mMDBRT and a new build up to 37° at 3780mMDBRT, the inclination is finally dropped to 22° at TD. DLS remain small (a maximum of 2.23°/30m is observed in the first dropping section at 3400mMDBRT). The azimuth (61°) is approximately constant over the main part of the well. D05 has been designed as a classical Dunbar well except that the 8 1/2" section (only the Brent reservoir was drilled) was covered by a 7" liner set in the Dunlin formation (TD at 4021mTVDBRT, 4500mMDBRT). While drilling the 8 1/2" section, large mud losses (up to $10m^3/hr$) were experienced both in static (mud weight initially 1.65SG decreased to 1.61SG to reduce the losses) and dynamic conditions (1000 and 1400l/min, ECDs between 1.68SG and 1.70SG depending on the flow rate and the static density). A total of $400m^3$ were lost. Open hole RFT showed a pseudo-virgin state in the whole Brent (pore pressures between 1.53SG to 1.56SG). The well was then suspended without being perforated.

After four years suspension, the parent hole was re-entered, cleaned, perforated and temporarily completed to be tested. The results of a new set of RFT logs (between 1.19SG and 1.22SG) showed a high depletion level due to production of nearby wells. A PLT flow log (**Fig. 2b**) confirmed that the UMS was divided into an upper tight zone (level 1 of **Fig. 2b**) producing only 1.2% of the total flow and a lower permeable zone (levels 2 and 3) producing more than 50% of the total flow, the rest coming from the Basal Sands (level 4). To better investigate the potentiality of the tight zone (in which large amounts of oil are trapped) it was decided to perform a 1000 m lateral drain in the top UMS.

Main constraints of the lateral drain - Planned trajectory

Understanding the reservoir disposition within the Dunbar field has improved with the development campaign. It has become clear that the permeability of the Frontal panel, into which D05 was drilled deteriorates below 3650mTVDSS. Large quantities of hydrocarbons are locked in reservoir sands with permeabilities of less than 2mD. Horizontal wells were identified as part of a study as the best means of exploiting this considerable oil in place. The goal was to drill from the parent hole a 1000m horizontal drain in the upper, tight part of the UMS.

A first, technically conservative, possibility was to drill a large radius hole by milling a window in the 9 5/8" casing then initiating the kick-off in the Kimmeridge shales. This solution was rejected for two reasons. First of all, the Kimmeridge being very unstable requires heavy mud weights (up to 1.70SG) at high inclinations[3]. Given the depletion in the Brent (1.20SG), this would have required covering the Kimmeridge with a 7" liner before lowering the mud weight to drill the horizontal drain. Secondly, sealing of the connection between parent hole and horizontal drain was not guaranteed preventing a future possible conversion to an injector.

The chosen solution was consequently to kick-off at the top Brent (3701m TVD) after milling a window in the 7" liner. According to the main constraint imposed by Total Oil Marine's reservoir department (horizontal drain constrained within level 1 of the UMS the bottom of which was at 3750mTVDBRT) it was required that the depth of the lowest point be 3745mTVDBRT, the horizontal drain being located at 3731mTVDBRT (**Fig. 2b**). Furthermore, the azimuth (N165°E) of the drain being very different from that of the parent hole (N55°E) both build and turn required very high DLS. However, a second constraint in the designed trajectory was to maintain DLS below an arbitrary 42°/30m. To achieve it, it was planned (**Fig. 3**) to separate the kick-off section into a first build/turn section with the max. DLS prescribed (42°/30m) reaching after approximately 100 meters N135°E azimuth and 94.7° inclination then into a final turn section with much smaller DLS (max. 3.2°/30m) to align the horizontal drain on its final N165°E azimuth.

Setting the whipstock. Milling the window in the 7" casing

The perforated parent hole (first perforations were at 4219mMDBRT) was killed using a blocking pill. A dummy run was performed with the MWD during the scraper run. Depth correlation was achieved directly against the formation using gamma ray. A retrievable whipstock (including the milling assembly - **Fig. 4a**) was run in hole and set at the top UMS using the gamma ray MWD correlation (**Fig. 4b**). The small difference between the optimal flow rate to transmit MWD data and the pressure required to set the whipstock anchor, resulted in some minor operational problems, however, the top UMS was clearly identified to within ± 1 meter [bottom of the anchor set 5.9 meters below the top UMS (4139.8mMDBRT)]. Two runs were necessary to mill the window (first mill was severely ringed-out after only three hours). Typical milling parameters were 2-15 tons WOB/9-15 kft.lbs torque/50-90RPM. The total duration of the whipstock/milling operation (including tripping time) was approximately 65 hours.

Drilling of the kick-off section

Drilling considerations. The kick-off was drilled using a BHA (Table 1) including a MF15HP rock bit, a short titanium downhole 4"3/4 motor with a 3° AKO setting and a short-radius MWD. The hole was steered with a directional MWD and a single gamma ray (no possibility to use a resistivity tool with such DLS). As pointed out in Table 1 the string was made of 3"1/2 DP, 3"1/2 HWDP and 5" DP (no DC in the string). To generate weight on bit effectively, the length of 3"1/2 DP was chosen in such a way that the HWDP remained in the parent hole. According to the RFT data (1.19SG to 1.22SG) a pseudo-oil based mud XP07 1.32SG was initially used.

The choice of AKO setting was based on offset well performance data. It had been shown that typically the BHA under-performs by about 5°/30m relative to the theoretical AKO setting. For this reason the AKO was set to give 47°/30m.

With respect to the planned trajectory which limited the DLS to a maximum of 42°/30m, the BHA over-performed the planned trajectory (**Fig. 3**) reaching 51°/30m. Build and turn were successfully achieved in two runs and 90m was sufficient to reach the landing point (95° inclination N165°E at 4242mMD). As pointed out in **Fig. 3**, these higher DLS moved the actual trajectory to the right of the planned trajectory. The main part of the kick-off was drilled in sliding mode (87%) but to limit the high build rate (**Fig. 5**) a single joint was drilled in rotary mode during each run. The ability to rotate the BHA at these high dog-legs was of tremendous value and unique to the titanium drilling motor.

Friction coefficient and torque at bit have been chosen to fit the experimental data as well as possible. As pointed out in **Fig. 6**, there is very good correlation between experimental and calculated data both in sliding and rotary mode. Friction coefficients and torque at bit have been estimated at 0.15 (in the casing), 0.2 (in the open hole) and 1500 ft.lbs.

Mud losses. The main problem encountered while drilling the kick-off and the beginning of the lateral drain was large losses (700m^3 of POBM were lost) initiated at 4176mMD (**Fig. 7a**) that is only 30 meters below the window. As already mentioned, such losses were observed while drilling the parent hole four years earlier exactly at the same vertical depth (3724mTVDBRT), both in static (using a 1.65SG mud weight to balance the pseudo virgin pore pressure) and dynamic conditions.

Drilling parameters before and after initiation of losses are discussed in **Fig.7 b**. As for the parent hole, they occurred both in static (circulation was stopped after approximately 30 minutes) and dynamic conditions (flow was reduced from 750l/min to 600l/min after 40 min) but initiated at a much lower mud weight (static mud weight was equal to 1.32SG). Reducing the mud weight from 1.32SG to 1.25SG did not solve the problem at all. Furthermore, when stopping the pumps, no back flow was observed. All these considerations are very consistent with mud injection in a natural fracture (it is not visible on the seismic section) and not within an induced hydraulic fracture, losses being clearly controlled by the current pore pressure and not at all by the fracturing gradient. The two points A and B where the losses occurred both in the parent hole and the lateral drain (**Fig. 7a**) allow us to consider line AB as the trace of the fracture plane. It is interesting to note that just before the losses started, (**Fig. 7b**) the stand pipe pressure exhibits a positive trend (for a constant flow rate) followed by a small pack off. They are both due to the crossing of the fracture.

To cure the problem the mud weight (from 1.32SG to 1.25SG) and the flow rate (from 750l/min to 600l/min) were both decreased then large amounts of Lost Circulation Material were pumped through the drill string. LCM partially plugged the downhole motor and the flow rate had to be slightly reduced which induced a sharp decrease in ROP (**Fig. 7c**). Consequently the BHA was POOH and the end of the kick-off section was drilled with a new bit (the first one was severely worn) but a similar BHA. During the second run the losses did not stop in spite of regularly pumping LCM.

Drilling the horizontal drain

Four runs (**Fig. 8**) were necessary to drill the lateral drain the final length of which (including the kick-off) was 1000m (927m of purely horizontal). A similar BHA including a M1X (6.32m) motor and a MWD (gamma/directional only for the same reasons as previously mentioned) (**Table 2**) was used but three different PDC bits (BBL880, DS71 GFT and M33 SPX) were tested. The average drilling parameters corresponding to each of the four runs are summarised in **Table 3**.

Third run and final cure of the losses. Run#3 was drilled with a BBL880 PDC bit. The sliding percentage decreased sharply (only 32% of the whole section). At the end of the third run a plugging of the downhole motor with a drastic decrease in ROP was observed (**Fig. 9**). Once more, the origin of this plugging is clearly LCM material regularly pumped during this third run.

To definitively cure the losses (in the range of 10m^3/hr at the end of Run#3), a stinger was RIH after the third run and a hi-vis pill followed by a high concentration LCM pill (300kg/m^3) were squeezed in the leaking fracture. This operation was very successful and no more losses occurred thereafter.

Fourth, fifth and sixth runs. Run#4 (DS71HGT - 205m - 14.5 hrs) was stopped due to a MWD problem. A post analysis showed that the MWD was washed out probably by abrasive sand particles cycling within the mud. A more severe centrifuging was advised for the next two steps. For Run#5, a M33 SPX bit was used but due to an insufficient ROP (8.4 m/hr) it was POOH after 21.4 hrs and 181m. Finally, Run#6 was drilled with a second BBL880. The results both in average ROP (8.4 m/hr over 44.25hrs) and drilled length (367m) were satisfactory. Finally, Runs#3,4 and 5 and 6 only required minor correction runs (8% of average sliding over the last 750m).

***Torque calibration* - ROP discussion.** As pointed out on **Fig. 10a**, measured torque at surface only slightly increased at the end of the last run but from a general point of view, torque remains nearly constant during the drilling of the whole horizontal drain. Torque has also been calculated using a classical drill-string model with the same friction coefficients (0.15 in the casing and 0.20 in the open hole) as those obtained from the kick-off runs (**Table 3**). The fit between average experimental and calculated data allows the calculation of the torque at bit for the four different PDC bits. Torque at bit is particularly low for the third bit (M33 SPX) for which a quick deterioration of the ROP was observed (**Fig 10b**).

TLC logging

Given the high DLS reached in the kick-off section, LWD was reduced to a gamma ray. To confirm that the drain was constrained within the upper part of the UMS, a resistivity log (TLC mode) was required. The resistivity log along the whole drain is presented in **Fig. 11**. It is very flat in the whole horizontal section but quite disturbed in the kick-off section.

Wellbore stability and sand production risks assessment

The Brent reservoir is usually drilled with a mud weight balancing the virgin pressure (between 1.60SG and 1.65SG), then covered by a cemented liner to be produced. However, given the depletion of D05 (1.19SG to 1.22SG) it was highly recommended to drill the lateral drain with a much lower mud weight to avoid differential sticking problems. Consequently, it was necessary to assess the stability of the drain both in drilling and production conditions. An extensive rock mechanics study including triaxial core tests, hollow cylinder tests and wellbore stability calculations have been carried out in Total's laboratories (**Table 4**). Both experimental results and theoretical calculations have shown that the drain was perfectly stable in drilling and production conditions even at abandonment. Consequently it has been decided to produce the drain in open hole conditions. Perfect hole stability has been proved while drilling and currently no sign of sand production has been reported.

Conclusions

The objectives of the drilling programme were fully met. A drain of 1000m length was exposed, all within the tight portion of the UMS sands. Logging data was collected which confirmed the homogeneous nature of the sandstone. Hole conditions throughout the drilling were excellent, without any tight spots, validating the pre-campaign rock mechanics investigation. The trajectory achieved was better than that planned. The use of titanium metallurgy within the drilling motor has increased the strength of the BHA components such that intermediate radius wells can be drilled in both sliding *and* rotary modes.

The well was brought on stream on 23rd January 1998 after a campaign duration of 32 days. Production from the tight zone, as measured prior to the lateral drain through a temporary completion, was 65bbl/day. The well test performed immediately after the clean-up indicated a production of 5500bbl/day from the lateral alone. This massive increase demonstrates a clear success for the lateral drain as the appropriate well architecture for the problems posed by tight sands. More important is the amount of oil that has been 'unlocked' by this technique. Reservoir estimates prior to the lateral figured on 4.39×10^6 barrels being drainable from the tight areas. Now estimates are in the region of 8.96×10^6 barrels. This was achieved without losing the possibility of draining zones in the parent bore below the depth of the UMS. D05z lateral is the first extremely long lateral drilled in the North Sea after an intermediate radius curve. The combination of high DLS (up to 51 deg/30m), TVD (3570m) and length of the drain marks it as one of the most challenging wells drilled in the North Sea.

The opportunities that the success of this well are considerable. The re-utilisation of investments made in existing wells, to side-track them into new panels without having to re-drill formations presents very strong economic driving forces for considering more *"avant-garde"* well designs.

Nomenclature

E	Young's modulus (MPa)
ν	Poisson's ratio
UCS	Unconfined Compressive Strength (MPa)
k	permeability (mD)
ϕ	porosity (%)

Acknowledgements

The authors thank Total Oil Marine plc, Elf Exploration UK PLC and Baker Hughes INTEQ for allowing publication of this paper

References

1. Y. Bigno, J. Baillie, T. Coombes (1997) "The Interpretation of Reservoir Pressure Data in the Dunbar Field (UKCS)" , SPE 37758 Middle East Oil Show held in Bahrain, 15-18 March 1997.
2. Ph. A Charlez, M. Easton, G. Morrice and P. Tardy (1998) "Validation of Advanced Hydraulic Modelling using PWD Data" OTC 8804 Houston May 1998
3. Ph. A. Charlez and A. Onaisi (1998) "Three History Cases of Rock Mechanics related Stuck Pipes while drilling Extended Reach wells in North Sea." SPE 47287 Eurock Trondheim July 1998

Serial Nb	Type	Length	OD
		[meter]	[inch]
MF15HP	Bit	0.23	5" 3/ 4
M1X1	Motor	2.99	4" 3/ 4
CSDP	Non-mag-DC	8.98	3" 1/ 2
	MWD	2.68	3" 1/ 2
CSDP	Non-mag-DC	9.46	3" 1/ 2
	X-over	3.04	3" 1/ 2

Elt Type	Sec Length	Elt OD	Joint Type	Weight
	[meter]	[inch]		[lbm/ft]
Drill-pipe	176.31	3" 1/ 2	WT38	15.5
HWDP	508.64	3" 1/ 2		
Drill-pipe	3624	5"	NC50 (XH)	19.5

Table 1 - BHA and drill string used for the kick-off

Serial Nb	Type	Length	OD
		[meter]	[inch]
	Bit	0.28	5" 3/ 4
M1X	Motor	6.32	5" 1/ 8
CSDP	Non-mag-DC	8.98	3" 1/ 2
	MWD	2.68	4"23/32
CSDP	Non-mag-DC	9.46	3" 1/ 2
	X-over	3.04	3" 1/ 2

Elt Type	Sec Length	Elt OD	Joint Type	Weight

	[meter]	[inch]		[lbm/ft]
Drill-pipe	675.04	3" 1/ 2	WT38	15.5
HWDP	508	3" 1/ 2		
Drill-pipe	3620.9	5"	NC50 (XH)	19.5

Table 2 - BHA and drill string (horizontal drain)

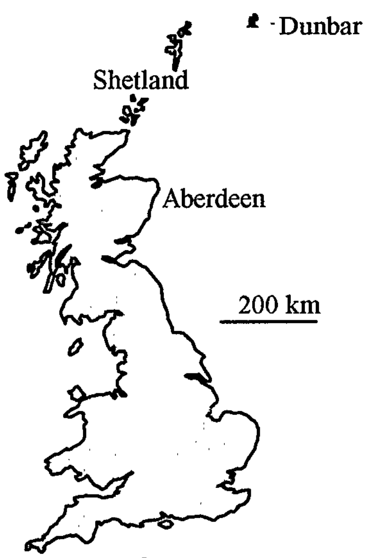
RUN	Bit	Depth	Sliding	Duration
g		m	%	hrs
3	BBL880	4242-4399	32.4	14.75
4	DS 71 HGT	4399-4604	6.9	14.5
5	M33 SPX	4604-4875	7.7	21.5
6	BBL880	4875-5152	11.7	44.25

RUN	ROP	RPM	WOB	Torq at bit	Flow
	m/h		tons	klb*ft	l/min
3	16.8	10 to 25	1 to 5	2700	810
4	19.2	30	2 to 4	2200	855
5	13.6	30	1 to 4	1200	850
6	11.2	30	3 to 5	1600	1000

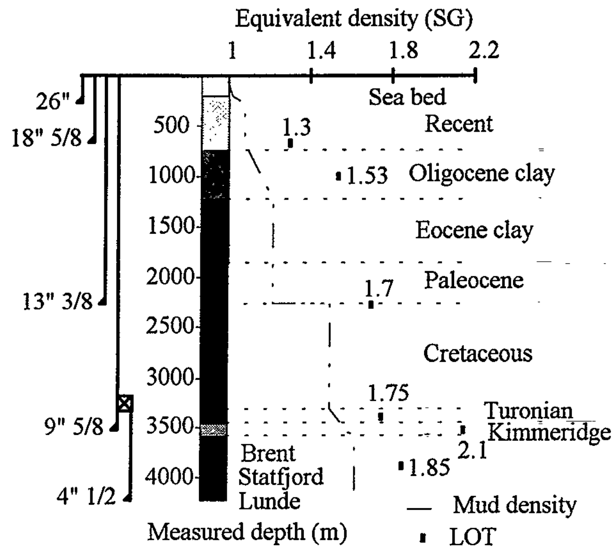
Table 3 - Average drilling parameters for the four runs of the horizontal drain

E	ν	UCS	ϕ	k	α
MPa		MPa	%	mD	
27000	0.3	36	15	1 to 30	0.7

Table 4 Mechanical properties of the Brent reservoir

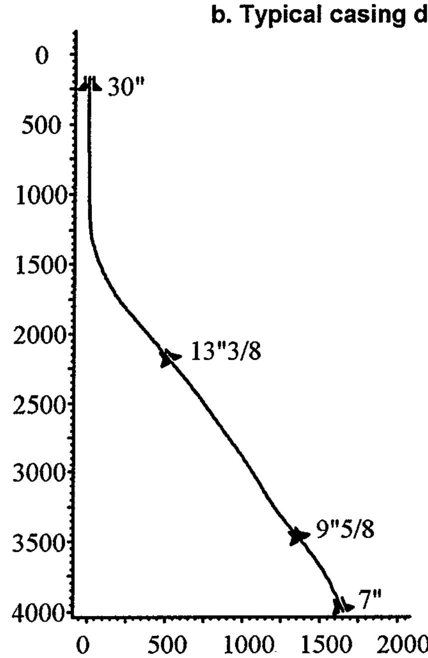


a



b

Fig. 1 a. Location of the Dunbar field
b. Typical casing design



a

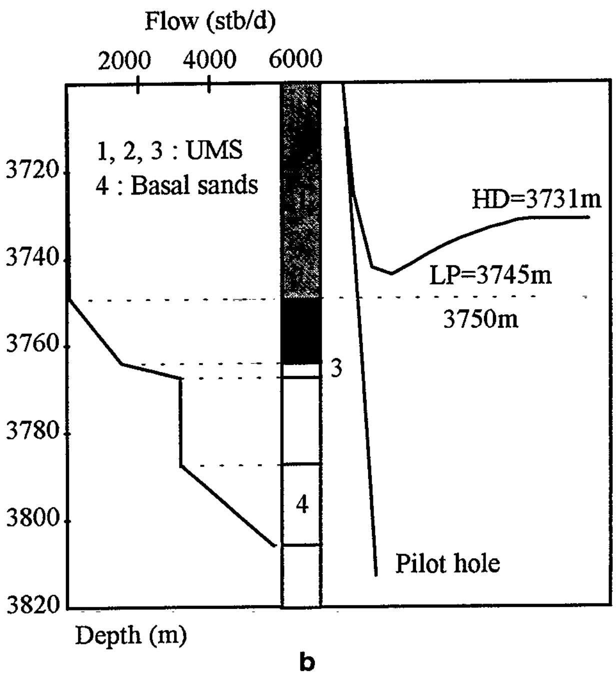


Fig. 2 Parent hole
a. Well profile
b. Results of PLT in the Brent

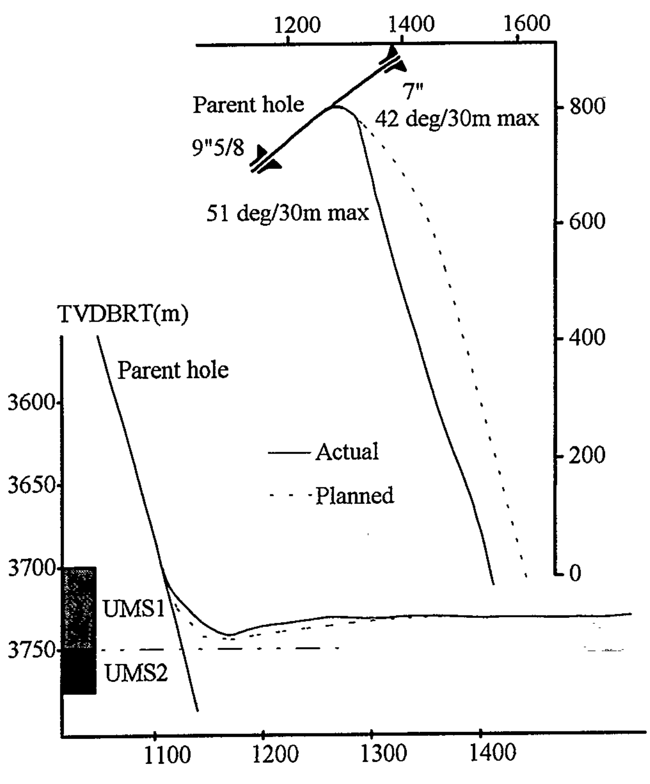


Fig. 3 Planned and actual trajectories

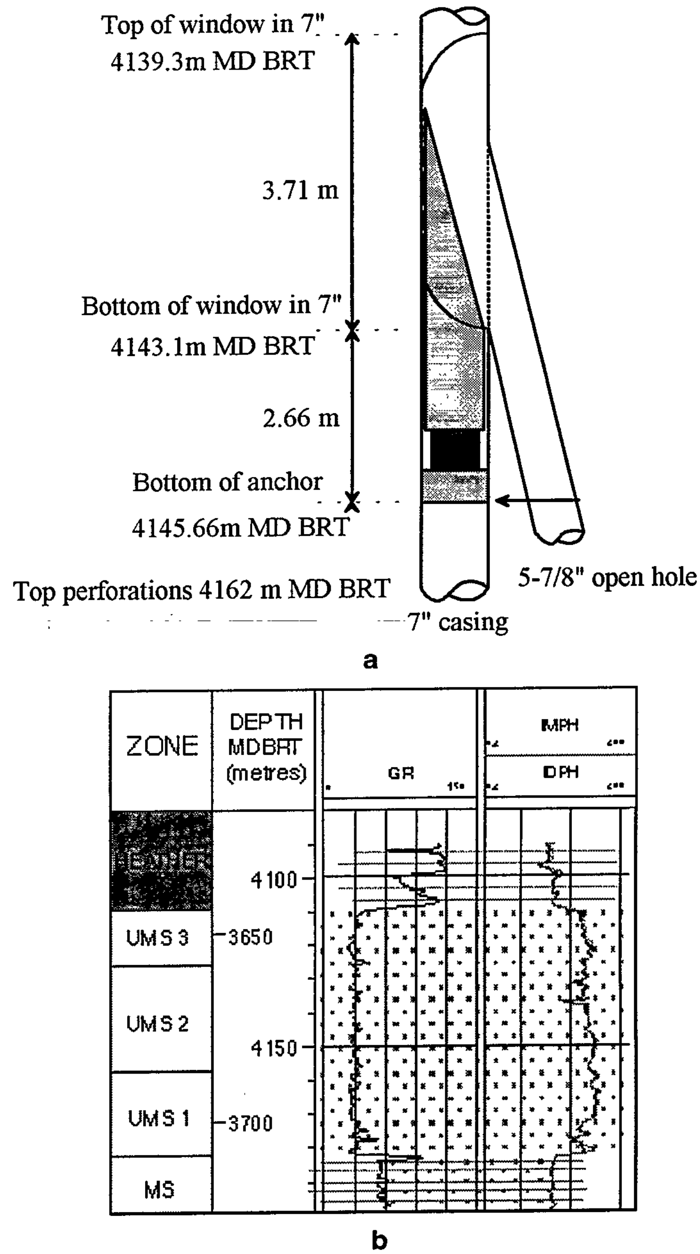


Fig. 4 Setting the whipstock and milling the window
a. Whipstock location
b. Gamma ray/Resistivity correlation

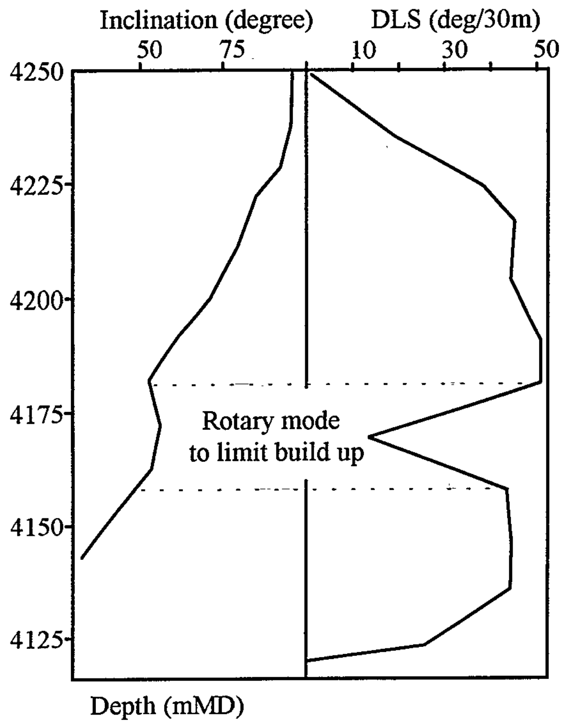


Fig. 5 Inclination and DLS of the kick-off section

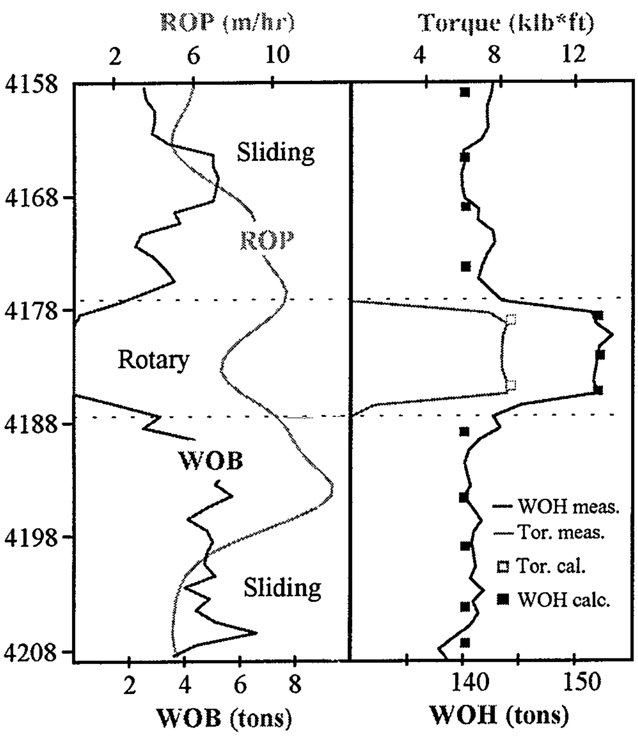


Fig. 6 Kick-off section
Drilling parameters during the first section

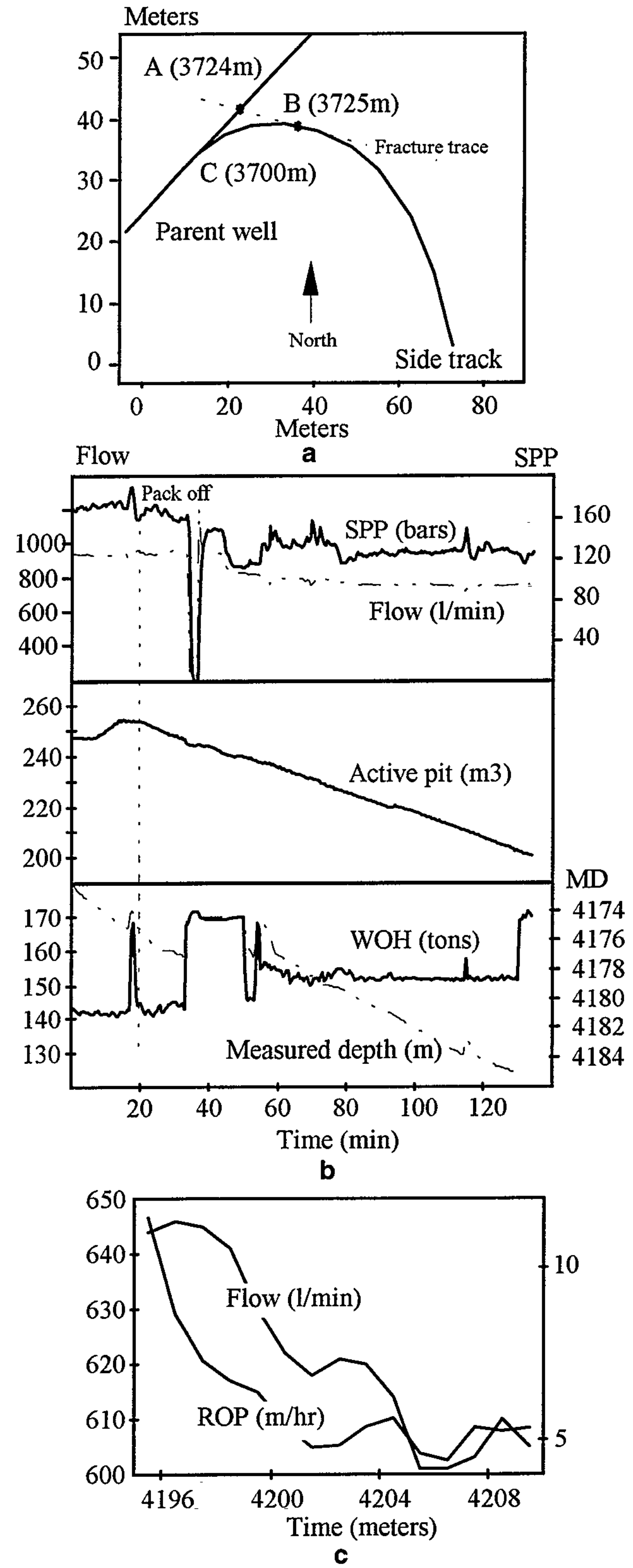


Fig. 7 Losses at 3725m TVD
a. Location of losses (parent hole and lateral drain)
b. Drilling parameters at the initiation of losses
c. Effect of LCM material on the plugging of the motor

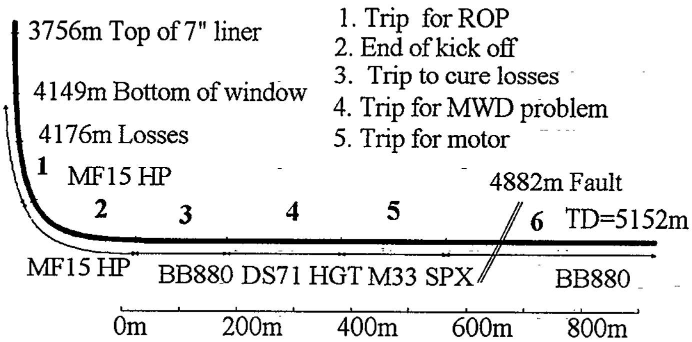


Fig. 8 Well summary

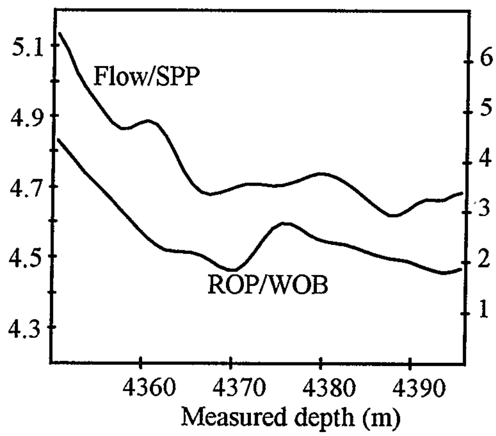


Fig. 9 Plugging of the downhole motor at the end of the third run.

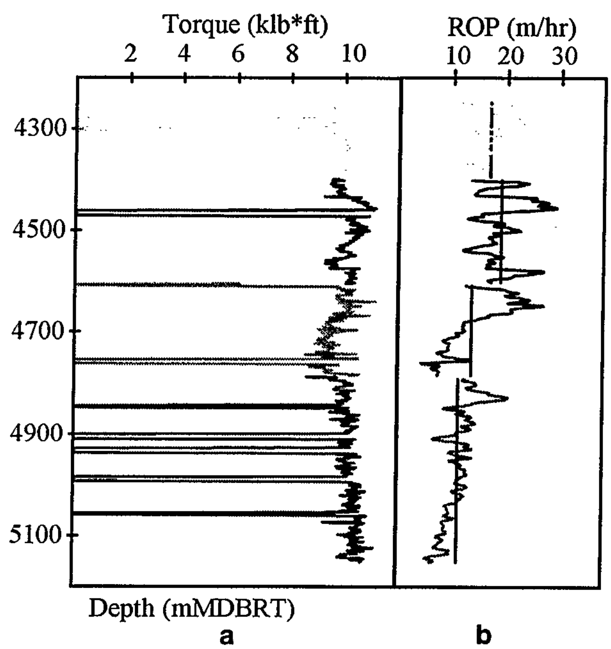


Fig. 10 a. Surface torque (drops correspond to sliding mode)
b. Filtered ROP

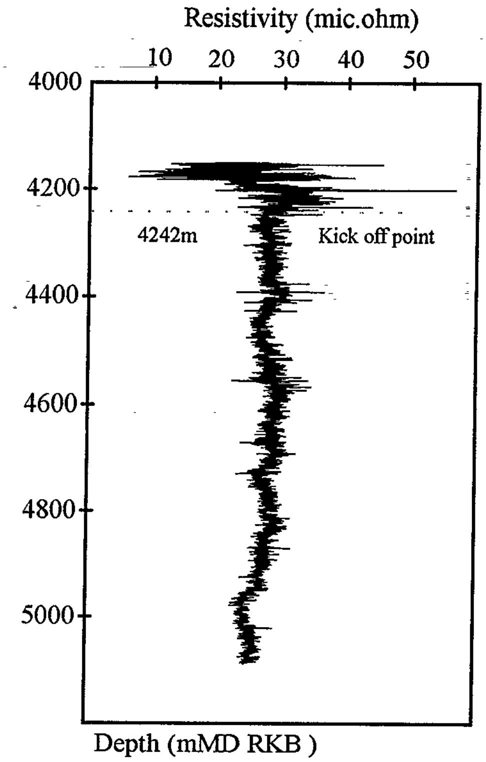


Fig.11 Resistivity log along the lateral drain.