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INVESTIGATION OF THE FEASIBILITY OF DEEP MICROBOREHOLE DRILLING

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ABSTRACT

Recent advances in sensor technology, microelectronics, and telemetry technology make it feasible to produce miniature wellbore logging tools and instrumentation. Microboreholes are proposed for subterranean telemetry installations, exploration, reservoir definition, and reservoir monitoring; this assumes that very small diameter bores can be produced for significantly lower cost using very small rigs. A microborehole production concept based on small diameter hydraulic or pneumatic powered mechanical drilling assemblies deployed on coiled tubing is introduced. The concept is evaluated using basic mechanics and hydraulics, published theories on rock drilling, and commercial simulations. Small commercial drill bits and hydraulic motors were selected for laboratory scale demonstrations. The feasibility of drilling deep, directional, one to two-inch diameter microboreholes has not been challenged by the results to date. Shallow field testing of prototype systems is needed to continue the feasibility investigation.

INTRODUCTION

Oil field drilling was initially performed with cable tools. Cable tool drilling was almost completely replaced by rotary drilling by the middle of the 20th century. Techniques to guide or steer the hole direction have been developed. Over the past decade many of these directional rotary drilling techniques have been adapted for use on coiled-tubing drilling systems. Coiled tubing allows rapid insertion and removal for bit replacement and bottom-hole-assembly (BHA) adjustments. Pressure control of a bore during insertion and removal is enhanced and well suited for underbalanced drilling. Recently, coiled-tubing manufacturers have inserted telemetry cables and small hydraulic tubing inside the coiled tubing. These developments provide a versatile and simple drilling platform that can support complex drilling processes such as real time bit location and steering for directional drilling, and logging while drilling as described by Leismer et al. (1996).

The coiled-tubing drilling platform discussed above and illustrated in Figure 1 is readily adapted to miniaturization. Conceptual drilling systems were designed based on a survey of commercial bottom-hole components. The smallest commercially available components for two conceptual systems, (1) a hydraulic rotary system, and (2) a hydraulic percussion rotary system, were tested to determine their actual performance. The feasibility of reducing the size of the BHA components to produce nominal 1-inch bore was investigated.

Present system requirements call for shallow, directional, river crossing trajectories drilled in rocks as hard as granite at a minimum 20-ft/hr drilling rate. Deeper vertical and directional bores in sedimentary rock are also believed to be feasible. Hydraulic and tubing buckling simulations support the case for deep drilling of microboreholes.

ANALYTICAL INVESTIGATION

The bore size and drilling power requirements determine the ultimate size of any drilling system, and the initial and operating costs of the system. An investigation to predict drilling performance as hole size is reduced was conducted for the proposed drilling system. Technical publications provided methods to calculate the effect of wellbore diameter on drilling process parameters. The effect of bore diameter on the requisite bit thrust and power for comminution at the specified rate of penetration was compared with projected maximum

hydraulic power and mechanical thrust that can be transmitted through the coiled tubing and efficiently converted to mechanical power in hydraulic drilling motors.

Bit Thrust. Drill collars are ineffective in highly inclined wells and will create large hydraulic losses. For this study it was assumed that bit thrust, as opposed to weight-on-bit, will be applied through the coiled tubing using a tubing injector on the drilling platform. It is assumed that the thrust limit is reached when buckling of the tubing occurs. Using the sinusoidal buckling load formula given by **Wu and Juvkam-Wold (1994)**, and assuming that the tubing-to-bore diameter ratio and tubing diameter-to-thickness ratio are held constant, a thrust limit in an inclined hole with low curvature scales as bore diameter to the 5/2 power, $D^{5/2}$. The thrust that causes the onset of buckling can be increased by reducing the radial clearance between the drill stem and the bore. Allowable compressive loading of the drill stem varies as the bore area or D^2 but the onset of buckling typically occurs long before compressive yield of the pipe.

PDC Bits. Polycrystalline Diamond Compact (PDC) cutter bits are well suited to coiled-tubing deployment because they provide a high rate of penetration at low input power and bit thrust as compared to other bits (**Glowka (1989 Parts 1 and 2)**). Typical PDC cutter sizes range from 0.3 to 0.5-inch diameter so bits as small as 1-inch diameter can be fabricated with commercial cutters. **Detournay and Defourny's (1992)** drag bit drilling model was used to predict theoretical performance limits as a function of bore size for shear bits. Using this model the effect of increasing bit speed to compensate for the limited thrust available before the onset of buckling can be quantified. A method to determine the allowable bit speed is needed to determine the theoretical maximum penetration rate.

A PDC cutter thermal performance model was developed by **Ortega and Glowka (1984)** and refined by **Glowka and Stone (1985)**. Cutter performance data (**Glowka (1989 Part 1)**) was input into the thermal performance model to calculate the maximum bit thrust that limits the cutter temperature to a value that assures acceptable cutter wear rates. By setting the temperature limited thrust and the buckling limited thrust equal, a quadratic function for the theoretical bit speeds that maximize bit power and rate of penetration can be calculated.

The two bit speeds and the tubing buckling load, the maximum bit thrust, are entered into the drilling model, **Detournay and Defourny (1992)**, with typical values for rock and bit cutter properties; two penetration rates as a function of bit diameter are generated. The higher curve is the maximum theoretical penetration rate; it varies as $D^{-3/2}$ over the larger hole sizes and the negative slope increases to $D^{-5/2}$ in the transition region between slimhole and microhole. Therefore, as bore size is reduced the maximum theoretical penetration rate for a shear bit increases significantly.

General Comminution. Substituting reciprocating frequency for rotary speed, and modeling percussive drilling performance using methods presented by **Hartman (1963)** and **Fairhurst (1959)**, yields results similar to those obtained using **Detournay and Defourny's (1992)** drilling model. To the extent that multi-cone bits rely on combined shear and impact drilling processes, the theoretical PDC performance projections are presumed to be applicable to multi-cone rotary drilling as well. Bearing wear in multi-cone bits was not investigated and may have a greater influence on multi-cone bit performance than cutter wear.

Bit Power and Cuttings Transport. Hydraulic and pneumatic drilling systems combine the power transport to the BHA and cuttings production into a single medium. By operating hydraulic power transport systems at high pressure and relatively low flow rates, power losses are kept low. Hydraulic power transport with a fixed, high maximum operating pressure, produces a maximum power transport per unit area that is constant (varies as D^0), when a maximum annular velocity is specified. Hydraulic power transport does not limit the minimum diameter of a microborehole if relatively high pressure circulating pressures are assumed. It can be shown that the optimum tubing diameter to hole diameter ratio for maximizing hydraulic power transport varies between 0.6 and 0.7 for a large range of drilling fluid properties and depths. As a result, coiled-tubing diameters optimized for hydraulic energy transport, will transmit the calculated bit thrust required to drill microboreholes at high penetration rates in most sedimentary rocks.

A Stokes Law settling criteria predicts efficient cuttings transport is readily achieved with the hydraulic power transport levels needed to achieve a reasonable rate of penetration in hard rock. For penetration rates up to several hundred ft/hr the effect of the cuttings removal process on energy transport can be ignored in vertical wells.

EXPERIMENTAL RESULTS

Experimental work focused on three areas: (1) selection and evaluation of bits for hard rock drilling, (2) selection and evaluation of appropriate hydraulic motors to provide the power required for hard rock drilling, and (3) evaluation of promising combinations of bits and motors to demonstrate the feasibility of their application to a coiled-tubing system.

Rotary Bit Testing. Rotary bit testing was conducted on a horizontal test stand. Circulating rates were set to match requirements for the rotary hydraulic motors selected for evaluation. Bits were run without nozzles for these tests.

The seven bits selected for evaluation were: two 1¼-inch bits made by a US mining bit supplier, a PDC bit with six 0.34 inch polycrystalline cutters, and a natural diamond impregnated bit; two 3-cone and two 2-cone Russian made rotary percussion bits, each type sized at 2.3 inch (59 mm) diameter, and a 1.8-inch (46 mm) diameter; and one 2.3 inch (59 mm) Russian made rotary surface diamond bit.

Three rock types were selected for drill bit testing: Berea Sandstone, Carthage Marble (Limestone), and Sierra White Granite. Typical values of compressive strength are 7,500 psi, 12,000 psi and 15,000 psi, respectively

Table 1 is a summary of the bit test results including the calculated specific energy. The three best tests are listed for the Russian bits. Test 528 run with the 2.3-inch 3-cone bit in granite at a bit thrust of 1500 lb_f provides a comparison with percussion rotary drilling (Test 527A in **Table 4**). The low penetration rate is a result of the low bit thrust and not a failure of bit. These bits showed visible bearing wear after drilling 18 inches in granite but continued to drill even after drilling more than 10 ft of granite. The 2-cone bit failed during its first test in granite due to severe bearing wear that allowed the cones to contact each other.

The surface diamond bit (Test 519) performed best in granite drilling at 16 to 26 ft/hr with 1500 to 2750 lb_f thrust. This bit showed no wear after drilling 16 inches in granite. The 1.75-in PDC bit drilled at very high rates, up to 550 ft/hr, in marble with minimal wear but failed catastrophically before penetrating 2 inches in granite.

The bit testing results lead to the conclusion that: (1) a rotary drilling motor will need to deliver an output power of at least 5 hp at 700 rpm and 2000 lb_f thrust to bore 20-ft/hr in granite with a 2.3-inch surface set diamond rotary drag bit. (2) The motor will need to deliver an output power of at least 8.25 hp at 300 rpm and 2500 lb_f thrust to bore 20-ft/hr in granite with a 2.323-inch 3-cone rotary bit.

Motor Testing. Hydraulic powered rotary drilling uses positive displacement motors (PDM) based on the Moineau (Moyno) principle. Two motor sizes were fabricated: (1) a 1.50-inch diameter, 3-stage 1:2 single-lobe motor, and (2) a 1.69-inch diameter, 5-stage, 5:6 multi-lobe motor. **Figure 2** shows motor assemblies in a rotary and a percussion rotary BHA. The motors include a bearing pack, bent housing with a 0° bend, a flexible shaft and a rotor stator assembly.

Motor Dynamometer Testing. Both motor sizes were tested on a dynamometer to determine the performance of the complete motor assembly as the reactive torque was increased. Dynamometer test results are summarized in **Table 2**. The single lobe (1:2) motor was tested with two stators, #1 and #2, to ascertain the variability in the performance between "identical" units. There was significant variation in performance between the two stators at the maximum power point. The power and efficiency curves for stator 1 are shown in **Figure 3**. Only one stator was tested for the multi-lobe motor.

The stator manufacturer had great difficulty fabricating the multi-lobe stator and excessive interference between the rotor and stator is believed to be causing the large reduction in efficiency and erratic performance

observed in the multi-lobe PDM. This is confirmed by the very high no-load differential pressure recorded, 855 psi, for the multi-lobe PDM as compared to 224 psi for the single-lobe PDM.

Motor Drilling Tests. Table 3 is a summary of 4 motor drilling tests where flow rate was fixed and bit weight was gradually increased. Three motor bit combinations were tested: a 1-3/4-inch PDC bit on the single-lobe motor, a 1-3/4-inch diamond impregnated bit on the multi-lobe motor, and a 2.3-inch (59-mm) 3-cone bit on the multi-lobe motor.

These data show that in soft and medium hard formations, a PDC bit run on a high speed, low torque motor can produce very high penetration rates, 912 ft/hr at 1835 lb_f thrust in Berea Sandstone and 280 ft/hr at 1740 lb_f thrust in Carthage marble (Figure 4).

Harder formations like Sierra White Granite had to be drilled with a roller cone bit or a diamond impregnated bit run on a lower speed multi-lobe motor. The 1.75 inch diameter, diamond impregnated bit drilled 60 ft/hr at 3025 lb_f while the 2.323 inch, 3 cone roller bit drilled 20 ft/hr at 3025 lb_f. It is evident that microbore drilling systems can be assembled to produce high penetration rates in a wide range of formations from soft to very hard.

PERCUSSION ROTARY DRILLING TESTS. A GHH G-59UO Russian hydraulic hammer was used to conduct drilling tests with several bits. The hammer does not rotate; a schematic of the hammer in a percussion rotary BHA is shown in Figure 2. For testing, the hammer was assembled in series with a 1/2 hp, 150 rpm, hydraulic rotary motor. Table 4 is a summary of 4 of a total of 23 tests conducted. All tests were run using the 2.1-inch (54-mm) OD, 90.5-inch-long GHH G-59UO hydraulic hammer drill motor operating at 40 to 60 Hz and rotated at 150 RPM with an external hydraulic motor. To estimate the power delivered to the assembly, 1.5 hydraulic hp (hhp) was added to the hydraulic power supplied to the hammer.

The Russian hammer did not drill as fast as the PDM/shear bit combination. However, the specific energy and hydraulic power requirements compare favorably with PDM rotary drilling. The lower penetration rates may be justified in very hard formations if long bit life and significantly lower bit costs ensue. The percussion drilling system is operated at significantly lower circulation rates than PDMs. This could be important when drilling hard rock below unstable or unconsolidated formations.

A significant advantage of percussion rotary drilling is lower threshold bit thrust needed to develop reasonable penetration rates as compared with pure rotary drilling with roller bits. Comparing Test 527A in Table 4 with Test 528 in Table 1, it is evident that the penetration rate with 1500 lb_f thrust is increased from 1.5 to 11 ft/hr with the application of percussion motion.

SIMULATION AND DESIGN STUDY RESULTS

Commercial computer simulations were run to provide a more realistic estimate of tubing thrust and hydraulic transport of downhole power and cuttings than analytical methods yield.

Coiled Tubing Buckling. Simulation of tubing thrust performance was run for the following combinations:

- (1) three trajectories:
 - a) an 18°/100-ft trajectory starting at 45° (from vertical) and reaching a final inclination of 135° at 500-ft;
 - b) an 12°/100-ft trajectory starting at 60° and reaching a final inclination of 120° at 500-ft; and
 - c) a 3000-ft vertical trajectory;
- (2) three bore sizes: 2.25-inch; 1.75-inch, and 1.125-inch; and
- (3) for three coefficients of friction that bracket the range for fluid filled holes: 0.2, 0.4, and 0.6.

Where the tubing OD to hole diameter ratio exceeds 0.65 and the coefficient of friction is 0.3, the simulated bit thrust is sufficient to produce 200 ft/hr penetration rates in Carthage Marble. The combination of drilling fluids with a high lubricity and tubing to hole diameter ratios greater than 0.65 should render high performance microhole drilling in most sedimentary formations.

MUDLITE™ Hydraulics Simulation. A foam simulator for underbalanced drilling was run with properties for a low viscosity (10 cp. power law), drilling fluid, a 200 ft/hr drill rate, and a 0.023-in particle size, and no air flow. Pressure loss in a 5,000-ft-long, vertical, 3/4-inch diameter tubing and a 1.125-inch by 3/4-inch

annulus were calculated. In order to produce 5 hhp/in² on bottom with a 4.3 gpm circulation rate (150 ft/min annular velocity), a surface pressure of 6000 psi for a Power Law fluid was predicted. This surface pressure is 40% of the burst or 50% of yield pressure for a 70,000 psi minimum yield strength tubing. Bottom-hole power density of 5 hhp/in² with demonstrated conversion efficiencies should produce high penetration rates in typical sedimentary rock.

PROPOSED SYSTEM

Two conceptual, coiled-tubing deployed, directional drilling systems are proposed: (1) A **full-scale, prototype**, 2-1/4-inch hole diameter system which can be assembled from existing or sourced components with the exception of an orientation sub; (2) A **half-scale, microborehole**, 1-1/8-inch diameter system requiring components that must be redesigned, fabricated, and successfully bench tested before a field scale drilling demonstration can be initiated. It is believed that the half-scale components can be designed based on appropriate scaling of current designs and will require no breakthrough technology to achieve the required performance. However, breakthrough technology may be needed to successfully fabricate some of the critical half-scale components needed: i.e., the PDM rotors and stators, and components in the orientation sub.

The ultimate drilling system needs to be self-contained and highly portable. It will include: a drilling BHA, a coiled-tubing drill stem with a permanent internal telemetry cable, a coiled-tubing reel and injector, well pressure control equipment, circulating pumps and pits, and hydraulic and circulating pump motors.

Drilling BHA. The BHAs proposed are shown schematically in **Figure 2**. Both rotary and percussion rotary motors are proposed: (1) a high power, PDM motor that should produce high drilling rates but may not provide acceptable bit life in the very hardest formations; (2) a lower power hydraulic hammer motor below a very low power PDM to drill very hard formations. The **full-scale rotary BHA** includes:

- (1) a 2-1/4 inch drag bit (450 rpm @ 3000 lb_r for hard rock and 1300 rpm @ 1500 lb_r for soft rock);
- (2) a 1.50 inch diameter single-lobe PDM or 1.69 inch diameter multi-lobe PDM including: a 4000 lb_r thrust bearing pack, bent housing (0 - 3°), a rotor/stator assembly: a 104-inch-long, 5 stage, (5:6) multi-lobe (10-hp @ 450 rpm) motor or a 52-inch-long, 3 stage, (1:2) single-lobe (5-hp @ 900 rpm) motor;
- (3) a 1.875-inch diameter orientation sub; (4) a 1.875-inch diameter, 84-inch long, non-magnetic drill collar; and (5) a 1.375-inch diameter, 30-inch-long steering tool inside the drill collar.

The **full scale percussion rotary BHA** includes: (1) a 2-1/4 inch 3-cone or solid head bit (300 rpm @ 3000 lb_r bit thrust); (2) a 2.13 inch (54-mm) diameter, 90.5-inch long hydraulic hammer with a 12-joule by 40 Hz reciprocating motor and reflector assembly that provides mechanical and hydraulic isolation of the hammer from upper BHA; (3) a 1.50 inch diameter single-lobe PDM including: a 4000 lb_r thrust bearing pack, bent housing (0 - 3°), a rotor/stator assembly: a 45-inch-long, 2 stage, (5:6) multi-lobe (3-hp @ 300 rpm) motor; (4) an orientation sub; (5) a non-magnetic drill collar; and (6) a steering tool.

The half-scale assembly will be designed with diameters that are 1/2 the full scale components, speeds will be twice the full-scales speeds, load ratings will be 1/2 the full-scale ratings, and power output will be 1/4 the full-scale output.

Coiled Tubing. Coiled tubing for the full-scale system will be 1-1/4-inch OD, 0.109-inch wall, 70,000 minimum yield strength, tubing; it has a burst pressure of 14,830 psi, a yield pressure of 11,640 psi and a tubing to bore diameter ratio of 0.56 in a 2-1/4-inch hole. Coiled tubing for the half-scale system will be 3/4-inch OD, 0.067-inch wall, 70,000 minimum yield strength, tubing; it has a burst pressure of 14,730 psi, a yield pressure of 11,380 psi and has a tubing to bore diameter ratio of 0.67 in a 1-1/8-inch hole.

DISCUSSION

Based on the simulations, experimental results, and analyses completed, it appears that drilling full scale directional boreholes using a coiled-tubing deployed, hydraulically powered system is feasible and should produce high drilling rates in medium hard formations and reasonable drilling rates in very hard formations.

Theoretical models and simulations indicate that this system is also feasible at 1/2-scale dimensions with the potential for higher penetration rates.

While all of the needed directional drilling components (except for an orientation sub) have been identified, shallow field demonstrations are needed to determine if traditional coiled-tubing steering techniques are applicable for microborehole dimensions in hard rock or if major adaptations will be required. Field demonstrations are also needed to determine optimum drilling fluid properties, allowable circulation rates, and bit and hydraulic motor life and performance under realistic drilling environments.

Pneumatic Air Drilling. The initial investigation of components for the microborehole drilling system included a brief survey of pneumatic powered drilling components. An air drilling alternate system permits drilling where fluid returns are not expected. The air drilling system was not tested because suitable small turbines were not identified. There has been some success reported operating PDMs with air but no quantitative results on the performance of PDM motors using compressible fluids was located. The life expectancy of PDM stators using air is greatly reduced due to excessive friction heating of the stator. It is not known if the use of a spray or foamed air improves the stator life. This investigation should be continued because air drilling systems may be required for many drilling environments.

There appears to be no theoretical reason that air powered systems should not provide a high performance drilling system to some reasonable depth. The lower efficiency of pneumatic power transport as compared to hydraulic should be more than offset by improved comminution efficiency at the bit. PDM dynamometer testing with air, mist, and foam needs to be conducted and a theoretical analysis of air systems completed to determine depth and performance limitations. Small diameter, high power air turbines and air hammers that can be adapted for downhole service should also be tested.

CONCLUSIONS

1. A theoretical analysis shows that very high penetration rates can be produced with microbits operating at high rotary speeds.
2. A theoretical study has identified no reason that 3000 to 5000-ft-long 1-1/8-inch diameter bore holes can not be drilled using a coiled-tubing deployed, hydraulically-powered drilling assembly. By operating coiled tubing at higher pressures than presently practiced, even greater depths are possible.
3. Drilling demonstrations of critical BHA components and straight-hole drilling assemblies have demonstrated that penetration rates of 20-ft/hr can be achieved in granite and that much higher rates are readily produced in softer rocks. The drilling power and thrust requirements to produce these results can be delivered though a coiled-tubing drill stem and supplied by a very small but relatively conventional surface drilling assembly. Shallow field demonstrations are needed to assure that these results can be carried beyond the laboratory environment to more realistic drilling conditions.
4. A conceptual design for a full-scale, 2-1/4-inch, directional drilling system has been developed from essentially off-the-shelf commercial components and subassemblies.
5. A conceptual design for a half-scale, 1-1/8-inch, microborehole-sized drilling system is proposed and found to be feasible based on analytic calculations and simulations. Redesign of commercial components as half-scale components is believed to be feasible. No obvious need for breakthrough technology was identified and development of prototype assemblies for bench testing is proposed.

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the Russian manufactured equipment for evaluation, coordinated its testing, and prepared the documentation for the test results. Dr. Yuri Malamed, of SKB Geotechnika, Moscow, Russia, directed the testing of the hydraulic hammer. The tubing thrust simulations were performed by Mr. Scott Quigley, with CTES, L.C., Conroe, Texas.

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TABLE 1 - Bit Test Summary

Test	Control Ramp	Rock Type	Bit Description		Bit Performance				
			Size (in)	Type	Speed (rpm)	Thrust (lb _f)	Torque (ft-lb _f)	ROP (ft/hr)	SE (kpsi)
496	Thrust	CM	1.750	PDC	650	3400	55	325	19
498	Thrust	CM	1.750	PDC	1300	3200	52	550	18
497	Thrust	CM	1.750	DI	650	3800	51	23	144
499	Thrust	CM	1.750	DI	1300	3700	32	65	96
504	Speed	CM	1.750	PDC	1350	1000	26	60	112
505	Speed	CM	1.750	DI	1400	1000	21	31	255
506	Speed	CM	1.750	PDC	1150	1750	26	210	30
507	Speed	CM	1.750	DI	1400	1750	27	40	160
508	Speed	CM	1.750	PDC	1200	2500	32	380	25
509	Speed	CM	1.750	DI	1400	2500	30	60	100
512	Thrust	BS	1.811	3-C	300	2000	25	40	100
517	Thrust	SWG	1.811	3-C	300	3700	52	22	370
519	Thrust	SWG	2.323	DS	700	2750	36	26	80
528	523D	SWG	2.323	3-C	150	1500	28	1.5	1500

TABLE 2 - PDM Dynamometer Test Summary

Test	PDM		Input Parameters			PDM Performance			
	Stator	Lobe	Flow (gpm)	DP* (psi)	HHP* (hp)	Torque (ft-lbf)	Speed (rpm)	BHP (hp)	EFF (%)
500	1	1:2	32	1450	27	56	1420	13	48
501	1	1:2	43	1900	47	60	1700	20	42
502	2	1:2	32	1325	24	45	1300	11	46
503	2	1:2	43	1850	46	60	1675	19	45
505	1	5:6	22	1025	14	80	90	1.2	9
506	1	5:6	35	1225	26	115	275	6.6	25
507	1	5:6	43	1075	27	130	440	10.2	38

* DP = differential pressure, HHP = hydraulic horse power

TABLE 3 - PDM/Bit Drilling Test Summary

Test	Rock	BHA		Hydraulic Input			PDM Bit Performance		
		Bit	Lobe	Flow (gpm)	DP (psi)	HHP (hp)	Thrust (lbf)	ROP (ft/hr)	SE (kpsi)
526	BS**	PDC***	1:2	30	1275	22	1835	912	20
529	CM**	PDC	1:2	29	1300	25	1740	280	60
530G	SWG**	DI***	5:6	32	940	18	1940	20	720
				30	1350	26	3025	60	350
537	SWG	3-C***	5:6	40	1400	33	3025	20	800

TABLE 4 - Percussion Rotary Drilling Test Summary

Test	Rock	Bit		Hydraulic Input			PDM Bit Performance		
		Size (in)	Type	Flow (gpm)	DP (psi)	HHP (hp)	Thrust (lbf)	ROP (ft/hr)	SE (kpsi)
521A	CM**	2.3	2-C	8.75	570	4.4	2175	14.8	140
522D	CM**	2.3	3-C	7.7	530	3.9	2980	17	110
523D	SWG**	2.3	3-C	10.5	705	5.9	2200	9.5	295
527A	SWG	2.3	3-C	11.1	660	4.3	1540	10.6	330
527B	SWG	2.3	3-C	11.6	710	6.4	3030	13.3	230

* DP = differential pressure across PDM/bit

HHP = hydraulic horse power input (includes an assumed 1.5 hp for the rotary power required to rotate the HHM and bit)

ROP = rate of penetration

SE = specific energy = specific total process energy based on hydraulic input energy

** CM = Carthage Marble (limestone), BS = Berea Sandstone, SWG = Sierra White Granite

*** PDC = 1-3/4 inch polycrystalline diamond compact cutter drag bit

DI = 1-3/4 inch diamond impregnated drag bit, DS = 2.32-inch diamond surface cutter drag bit

2-C = two cone rotary bearing bit, 3-C = three cone rotary bearing bit.

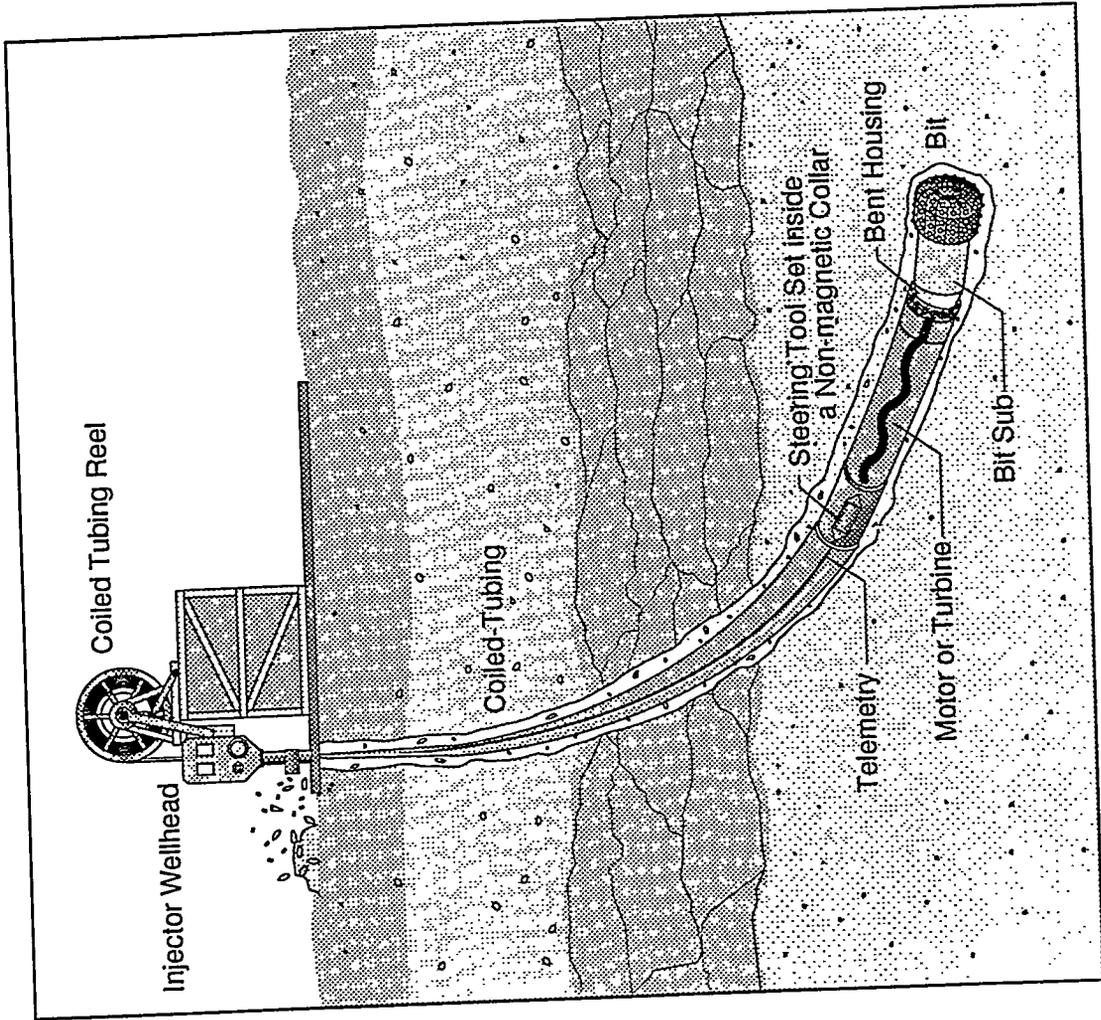


Figure 1 Schematic of Microdrilling Concept.

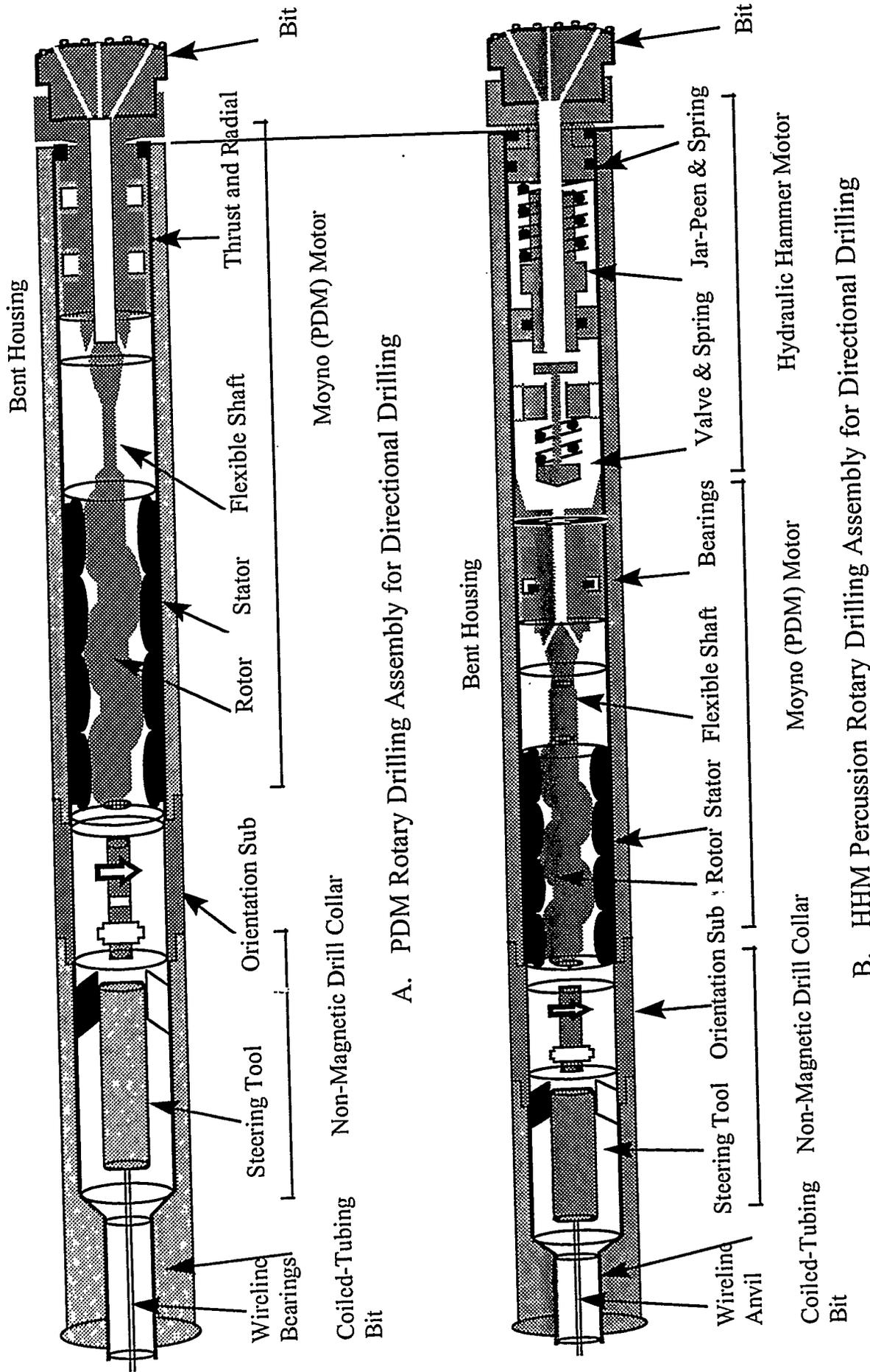


Figure 2 Schematic of proposed conceptual drilling assemblies.

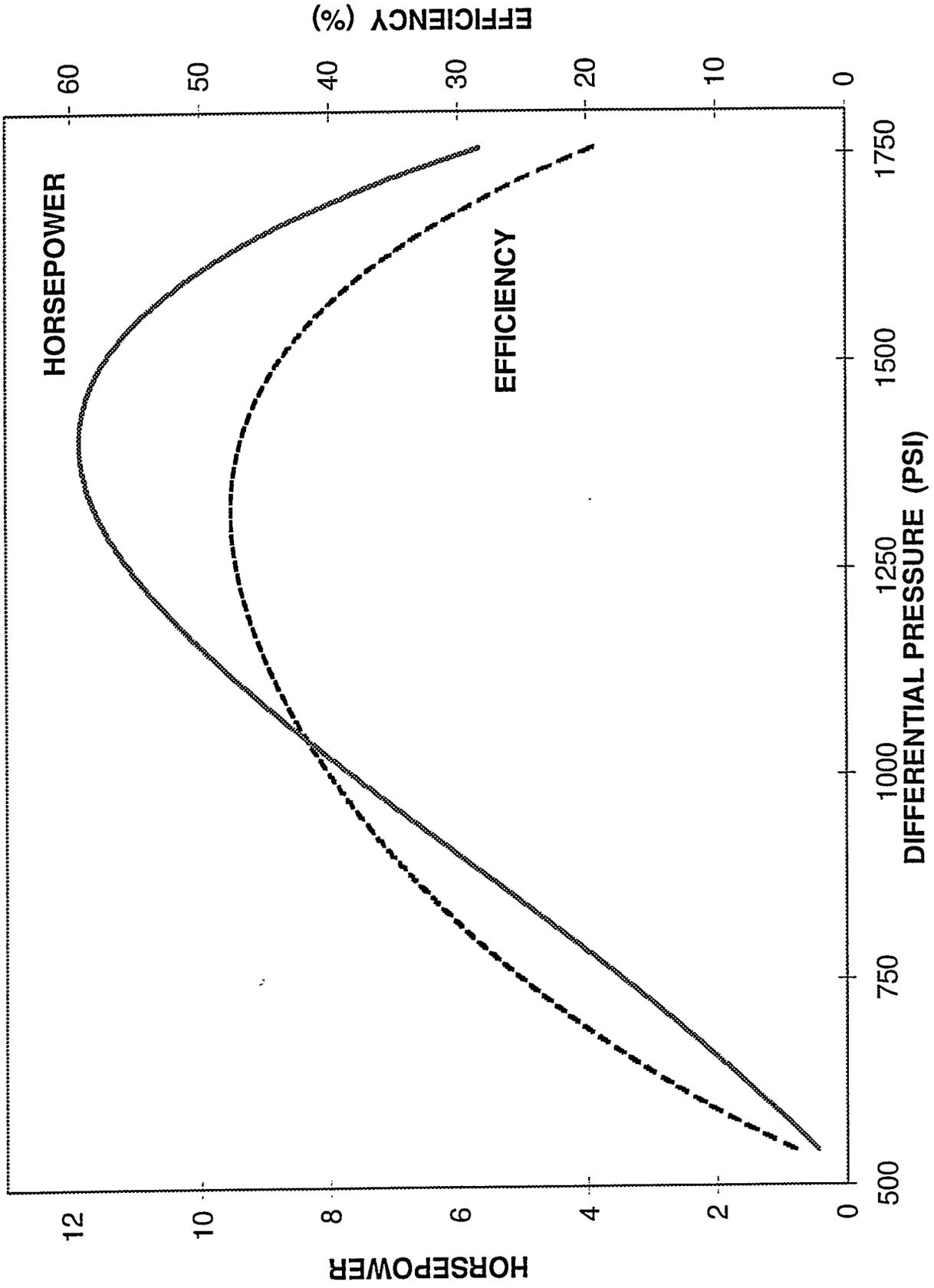


Figure 3 Test 500 - PDM dynamometer test results for 1.5-inch diameter, single-lobe motor.

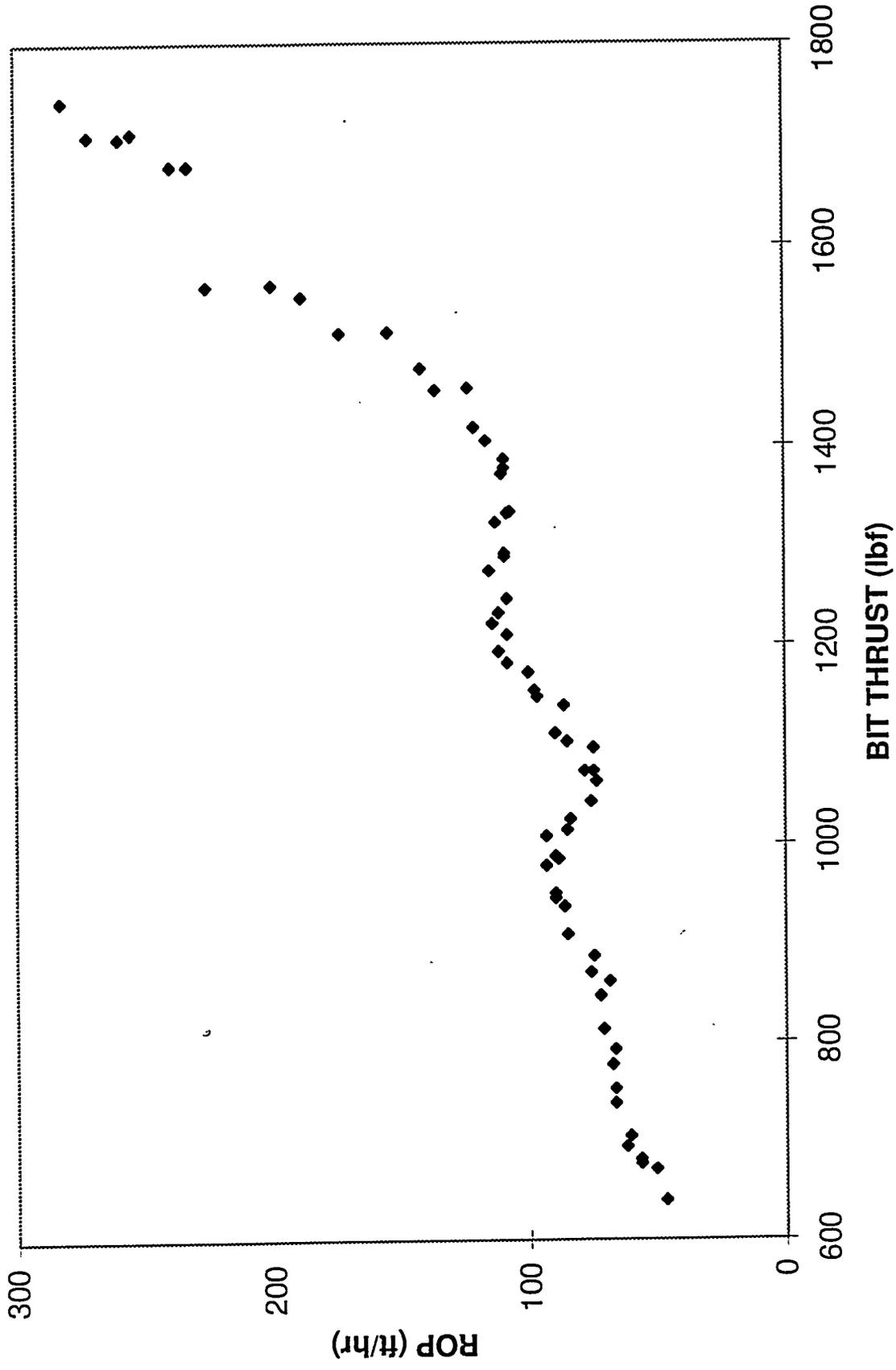


Figure 4 Test 529- rotary drilling results for the single-lobe PDM and PDC bit in Carthage Marble.