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Micro Borehole Drilling Platform

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Micro Borehole Drilling Platform Study

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I. EXECUTIVE SUMMARY

This study by CTES, L.C. meets two main objectives. First, evaluate the feasibility of using coiled tubing (CT) to drill 1.0"-2.5" diameter directional holes in hard rocks. Second, develop a conceptual design for a micro borehole drilling platform (MBDP) meeting specific size, weight, and performance requirements. The *Statement of Work* (SOW) in Appendix A contains detailed specifications for the feasibility study and conceptual design. Table 1 shows the hole size, CT string, and bottom hole assembly (BHA) combinations evaluated.

Table 1: Candidate CT Strings

Case	1	2	3	4	5	6	7
Borehole ID (in)	1.125	1.875	2.250	1.125	1.875	2.250	2.250
CT OD (in)	0.625	0.750	1.000	0.750	1.000	1.000	1.250
CT Wall (in)	0.049	0.067	0.087	0.067	0.087	0.109	0.095
BHA Length (ft)	17.25	22.83	22.83	17.25	22.83	22.83	22.83
BHA Weight (lbs)	10.78	49.48	53.29	10.78	49.48	53.29	53.29

Cases 1-3, prescribed in the SOW, result in marginally acceptable weight on bit (WOB). Cases 4-7, added during the study, provide satisfactory WOB with 2.5-10 ppg fluids in the directional boreholes, but insufficient WOB for drilling vertically at 2000'. Only case 7 gave satisfactory WOB in the directional boreholes with air (0.6 ppg). Based on these results, 0.75" and 1.00" CT could provide adequate mechanical performance for most of the drilling conditions described in the SOW.

Fatigue life of CT decreases with increasing OD, increasing pressure, decreasing wall thickness, and decreasing reel core diameter. CTES evaluated the effects of these parameters on the fatigue life of the CT strings in Table 1. These CT strings would survive at least 200 trips at 2000 psi internal pressure for the MBDP conceptual design developed by this study.

The SOW specifies at least 2500 psi pressure at the CT reel inlet but not a minimum drilling fluid flow rate. This study assumed the CT string length was 2500' for all cases. Based on the properties of 8.5 ppg salt water, 0.75" and 1.00" CT could deliver approximately 15 gpm and 35 gpm respectively with 2500 psi at the reel inlet. Reducing the CT string length to 600' for the directional boreholes would significantly increase these flow rates.

The basis of the MBDP concept is a hydraulically-powered CT reel and injector in a compact arrangement that eliminates the need for a guide arch (gooseneck). The MBDP could operate at any drilling angle from vertical (down) to horizontal. The overall

dimensions (L x W x H) for each case are 9'-8" x 6'-9" x 14'-8" and 14'-8" x 6'-9" x 7'-9". The weight of the MBDP without CT is approximately 6900 lbs. The injector could handle 0.625"-1.250" CT and apply 17,000 lbs push or pull. Total power required to operate the MBDP would be approximately 100 HP. The conceptual design includes a performance specification, a primary components list, preliminary layout drawings, and an engineering cost estimate.

II. INTRODUCTION

The main objectives of this study are to:

- (1) evaluate the feasibility of using CT to drill 1.0"-2.5" diameter holes in hard rocks to vertical depths of 2000' or directionally to 500'
- (2) develop a conceptual design for a MBDP meeting specific size, weight, and performance requirements.

The SOW, Appendix A, contains detailed specifications for the feasibility study and conceptual design.

The first step was to determine if the three combinations of hole size, CT string, and BHA specified in the SOW could achieve the desired mechanical performance. Section III of this report describes this mechanical performance evaluation. Results from the tubing forces model in the Cerberus™ CT simulator showed that WOB would be marginal for each case. Parametric studies identified CT strings that could generate higher WOB in each borehole. These CT strings became the basis for hydraulic performance calculations and helped define the injector and reel operating limits.

The SOW did not specify any hydraulic performance for the MBDP. CTES conducted a limited hydraulic performance evaluation in order to identify potential problems for hole cleaning, bit hydraulics, or drilling motor operation. Section IV discusses the evaluation of MBDP hydraulic performance.

CTES has participated in similar conceptual design studies with Hydra Rig of Fort Worth, TX. One of those studies produced a miniature CT unit for operating inside small maintenance tunnels. For another study, Hydra Rig produced a compact CTD unit for trenchless drilling. The present study drew heavily on the knowledge and experienced gained from those previous studies. Consequently, the MBDP concept is a compact arrangement of CT reel and injector that eliminates the bulky guide arch. Section V describes the novel MBDP design, performance specification, primary components, and engineering cost estimate.

III. MBDP MECHANICAL PERFORMANCE EVALUATION

Orpheus™ and Achilles™ are tubing forces and fatigue models respectively in the commercially-available Cerberus software suite developed by CTES. Orpheus predicts the forces and stresses on the CT and buckling and lockup conditions. Numerous CT service companies routinely use both models to evaluate the feasibility of proposed CT operations.

A. Tubing Forces and Buckling

The mechanical performance evaluation began by determining the maximum WOB possible with the three combinations of hole size, CT string, and BHA specified in the SOW. For a given combination of fluid density and friction coefficient (Cf) in each of these three scenarios, Orpheus increases the compressive axial force at the bottom of the BHA for running into the hole (RIH) until either:

- (1) the CT string locks up (drag due to buckling prevents transmission of axial force), or
- (2) the von Mises equivalent (VME) stress somewhere in the CT string exceeds 80% of tubing yield strength.

1. SOW Parameters

Table 2 shows the combinations of borehole, CT string, and BHA configurations specified by the SOW. "HTB" simply means Hole, Tubing, and BHA. Orpheus modeled the BHA as a hollow cylinder with OD and ID of the non-mag drill collar and length and weight of the total BHA. The wall thickness for each CT size is commercially available.

Table 2: CTD Components - SOW

Component	Properties	HTB 1	HTB 2	HTB 3
Borehole	ID (in)	1.125	1.875	2.250
CT	OD (in)	0.625	0.750	1.000
	Wall (in)	0.049	0.067	0.087
Mud Motor	OD (in)	0.875	1.500	1.500
	Length (ft)	6.25	10.83	10.83
Non-mag Collar	OD (in)	1.000	1.750	1.875
	ID (in)	0.875	1.500	1.625
	Length (ft)	10.00	10.00	10.00
X-over	OD (in)	1.000	1.750	1.750
	ID (in)	0.500	0.616	0.866
	Length (ft)	1.00	2.00	2.00
BHA Overall	Length (ft)	17.25	22.83	22.83
	Weight (lbs)	10.78	49.48	53.29

The SOW specifies CT materials with 70,000 psi and 30,000 psi yield stress. The yield stress has no effect on buckling and lockup performance. These conditions are primarily a function of geometry. However, the choice of CT material limits the forces that CT of given dimensions can safely support. Table 3 shows the maximum allowable tension at 80% of yield stress for each CT string without a pressure differential.

Table 3: Maximum Allowable Tension at 80% of Yield Stress (No pressure)

HTB	CT Dimensions (in)		Yield Strength (psi)	
			30,000	70,000
	OD	Wall	Max. Tension (lbs)	
1	0.625	0.049	2128	4965
2	0.750	0.067	3450	8051
3	1.000	0.087	5989	13,974

The SOW specifies three borehole trajectories, one vertical to 2000' measured depth (MD) and two directional to 500' MD. Table 4 shows the directional boreholes. LANL 12/100 has a build rate of 12°/100' and LANL 18/100 has a build rate of 18°/100'.

Table 4: Borehole Trajectories - SOW

MD (ft)	Hole Inclination (°)	
	LANL 12/100	LANL 18/100
0	45	60
50	54	66
100	63	72
150	72	78
200	81	84
250	90	90
300	99	96
350	108	102
400	117	108
450	126	114
500	135	120

(a) Orpheus Test Matrix and Parametric Study

A number of factors can affect the mechanical performance of a CT string and BHA during drilling. The radial clearance between the CT and borehole strongly influences the onset of buckling and post-buckling normal force. The latter causes significant drag which can limit the ultimate reach while RIH. The density of the fluids inside and outside the CT string determine its buoyed weight. For an inclined borehole, the buoyed weight has an axial component and a normal component. The former contributes directly to the axial force measured by the weight sensor on the surface equipment, and the latter contributes to drag between the CT string and borehole.

Frictional drag between the CT string and borehole is the product of normal force and C_f . The drag affects the surface weight measurement and the onset of buckling. Friction can delay buckling in a directional borehole, but, under certain conditions, may cause the CT string to lockup almost immediately after it buckles. Consequently, C_f is an important Orpheus input parameter. Most of the borehole for the proposed CTD operations would be rock. C_f for steel on rock can be 0.6-1.2 in dry air and 0.2-0.6 in fluids, depending on their lubricating qualities.

The remaining factor affecting the mechanical performance of the CT string is the borehole profile or directional survey. Borehole inclination directly affects the normal and axial force components of the CT string buoyed weight. The former causes drag and the latter contributes to WOB while RIH. The axial force required to buckle CT increases with increasing borehole inclination and curvature. However, drag between the CT string and borehole also increases with increasing borehole inclination and curvature. During RIH, the first condition delays buckling while the second condition promotes buckling. A CT simulator like Orpheus is required to resolve this dichotomy.

A well-designed parametric study considers all feasible combinations of the factors described above. Table 5 shows the matrix of factors investigated with Orpheus.

Table 5: Orpheus Test Matrix - SOW Parameters

Factor	Quantity	Values
Hole+CT+BHA	3	HTB 1
		HTB 2
		HTB 3
Fluid	6	0.6 ppg*
		2.5 ppg
		5.0 ppg
		8.6 ppg
		7.5 ppg
		10.0 ppg
Cf	7	0.2
		0.3
		0.4
		0.5
		0.6*
		0.9*
Borehole Profile	3	1.2*
		Vertical
		18°/100 ft
		12°/100 ft

* designates air

(b) Orpheus Analyzer

Orpheus contains a feature called *Analyzer* which vastly simplifies a parametric study. *Analyzer* evaluates all combinations of factors within ranges specified by the user for their effects on WOB, lockup depth, and surface weight while RIH and maximum stress in the CT while pulling out of the hole (POOH). These parameters are the most important indicators of the chances for a successful CTD operation with a given combination of factors.

Maximum WOB occurs just prior to lockup or when the VME stress somewhere in the CT string exceeds 80% of its yield stress. For this study, maximum WOB was not sensitive to fluid density in the range 2.5-10 ppg. The WOB values shown in Tables 6-8 are the averages of the values calculated for each fluid density for the given HTB, borehole trajectory, and Cf combination. The sign convention for axial force in these tables is

negative (-) for compression and positive (+) for tension. For each borehole geometry and profile, maximum WOB decreases with increasing Cf.

Table 6: Effects of Cf on Maximum Average WOB for HTB 1

HTB 1 Max. Avg. WOB (lbs), MW = 2.5-10 ppg					
Cf	0.2	0.3	0.4	0.5	0.6
LANL 12/100	-972	-787	-701	-621	-550
LANL 18/100	-1032	-879	-745	-627	-523
LANL Vertical	-656	-522	-448	-397	-363

Table 7: Effects of Cf on Maximum Average WOB for HTB 2

HTB 2 Max. Avg. WOB (lbs), MW = 2.5-10 ppg					
Cf	0.2	0.3	0.4	0.5	0.6
LANL 12/100	-1066	-803	-695	-600	-509
LANL 18/100	-1059	-874	-713	-570	-444
LANL Vertical	-781	-633	-548	-494	-453

Table 8: Effects of Cf on Maximum Average WOB for HTB 3

HTB 3 Max. Avg. WOB (lbs), MW = 2.5-10 ppg					
Cf	0.2	0.3	0.4	0.5	0.6
LANL 12/100	-2795	-2151	-1930	-1726	-1534
LANL 18/100	-2866	-2453	-2088	-1765	-1479
LANL Vertical	-1652	-1297	-1104	-981	-893

According to the SOW, drag bits need 100-2000 lbs axial force per square inch of hole area. Table 9 shows the WOB required to meet this criteria for each HTB case.

Table 9: WOB Required for Drag Bits (Hard Rock)

HTB	Hole ID	Hole Area	Bit Pressure (psi)	
			100	2000
	(in)	(in ²)	WOB (lbs)	
1	1.125	0.994	-99	-1988
2	1.875	2.761	-276	-5522
3	2.250	3.976	-398	-7952

Comparison of the WOB ranges in Table 9 with the *Analyzer* results in Tables 6-8 shows that the proposed CT strings are marginally adequate to provide the required WOB for drilling hard rock with 2.5-10 ppg fluids. This means the CT strings are not stiff enough to prevent lockup at the high WOB required for hard rock drilling. Increasing the CT wall thickness and/or diameter will increase its stiffness and buckling resistance. Figures 1-3 show the maximum average WOB values for these fluids converted to bit pressure.

**Figure 1: Effects of Friction on Maximum Average Bit Pressure
MW = 2.5-10 ppg and LANL 12/100 Survey**

Figure 2: Effects of Friction on Maximum Average Bit Pressure
MW = 2.5-10 ppg and LANL 18/100 Survey

Figure 3: Effects of Friction on Maximum Average Bit Pressure
MW = 2.5-10 ppg and Vertical Borehole

Table 10 shows that the CT strings proposed in the SOW are not satisfactory for drilling with air or gas. Maximum WOB in each case is barely more than the minimum requirement shown in Table 9.

Table 10: Effects of Cf on Maximum WOB for Air Drilling

Maximum WOB (lbs) for Air = 0.6 ppg				
	Cf	HTB 1	HTB 2	HTB 3
LANL 12/100	0.6	-547	-504	-1531
"	0.9	-355	-258	-1023
"	1.2	-203	-63	-617
LANL 18/100	0.6	-516	-434	-1465
"	0.9	-270	-125	-785
"	1.2	-105	0	-320
LANL Vertical	0.6	-379	-477	-934
"	0.9	-309	-398	-766
"	1.2	-270	-352	-668

Figures 4-6 show the WOB values from Table 10 converted to bit pressure.

**Figure 4: Effects of Friction on Maximum Bit Pressure
Air (0.6 ppg) and LANL 12/100 Survey**

Figure 5: Effects of Friction on Maximum Bit Pressure
Air (0.6 ppg) and LANL 18/100 Survey

Figure 6: Effects of Friction on Maximum Bit Pressure
Air (0.6 ppg) and Vertical Borehole

Figures 4-6 confirm that the proposed CT strings could only deliver bit pressures at the low end of the desired range. Increasing the CT wall thickness and/or diameter could alleviate this problem.

Table 11 shows the worst conditions the CT would have to withstand at the top of the borehole. The second column is the maximum snubbing force required to provide the highest WOB possible with each HTB. If the proposed CT strings were acceptable, these numbers would set the minimum snubbing power for the MBDP injector. The third column shows the maximum VME stress during POOH.

Table 11: Range of Conditions at MD = 0'

	Max. Compression	Max. VME Stress at POOH
	(lbs)	(psi)
HTB 1	-4848	17,211
HTB 2	-8182	14,888
HTB 3	-13,706	14,031

(c) Surface Weight While RIH and POOH

A useful output from Orpheus is surface weight versus MD. These data simulate what the CT operator would see on the weight indicator while tripping in/out of the borehole. This information has limited value at this point, since the *Analyzer* results presented above indicate the proposed CTD scenarios are not satisfactory. However, this section presents selected results to illustrate the concept of using surface weight data to evaluate the potential risk of a CT operation.

The absolute weight values are useful for setting the limits for an operation, but the trends in the data are a more important indication of how risky a CT operation might be. An abrupt increase in the slope of a curve during RIH signals a sudden increase in drag, usually because the CT has helically buckled. The corresponding signal for POOH is a sudden decrease in the slope of the curve at the same depth.

The smooth curves in Figures 7 and 8 for 8.6 ppg fluid and $C_f = 0.30$ do not indicate any helical buckling or localized high drag for any of the combinations of borehole, CT, and BHA. Surface weight versus MD for RIH and POOH in the vertical well is a single straight line with slope equal to the CT buoyed weight per foot. These results are typical for all other combinations of factors evaluated by this study and indicate low risk for tripping in/out of the proposed boreholes.

Figure 7: Surface Weight During Tripping for LANL 18/100 Survey
MW = 8.6 ppg, Cf = 0.30, WOB = 0

Figure 8: Surface Weight During Tripping for LANL 12/100 Survey
MW = 8.6 ppg, Cf = 0.30, WOB = 0

2. Revised CTD Components

The Orpheus runs described in the previous section showed that the CT strings proposed in the SOW would not be stiff enough to provide WOB of 2000-3000 lbs for the range of expected operating conditions. Increasing the CT wall thickness and/or diameter would increase its stiffness and weight, but the latter has the negative effect of increasing drag. Experiments with Orpheus suggested that increasing the diameter of each CT string in Table 2 to the next larger size and keeping the wall thickness reasonable would give satisfactory performance. Table 12 shows possible CT strings with their corresponding boreholes and Orpheus BHA models. These CT sizes are commercially available.

Table 12: CTD Components - Revised

Component	Properties	HTB 1-OD	HTB 2-OD	HTB 3-OD	HTB 3-1
Borehole	ID (in)	1.125	1.875	2.250	2.250
CT	OD (in)	0.750	1.000	1.250	1.000
	Wall (in)	0.067	0.087	0.095	0.109
BHA	OD (in)	1.000	1.750	1.875	1.875
	Length (ft)	17.25	22.83	22.83	22.83
	Weight (lbs)	10.78	49.48	53.29	53.29

Figure 9 shows how increasing CT size from 0.625" OD to 0.750" OD for a 1.125" borehole could provide 2000-3000 lbs WOB at 500' MD for 2.5-10 ppg fluids in the directional holes. LANL 12/100 and LANL 18/100 are the 12°/100' and 18°/100' borehole trajectories respectively. Unfortunately, the 0.75" OD CT is still not stiff enough to provide adequate WOB at 2000' in the vertical borehole.

**Figure 9: Effects of Friction on Maximum Average WOB
HTB 1-OD, 2.5-10 ppg Fluids**

Figure 10 shows the benefits for WOB of increasing CT stiffness by increasing wall thickness. However, increasing wall thickness is detrimental to CT hydraulics. The choice of wall thickness in each case would be a compromise between mechanical and hydraulic performance objectives.

Figure 10: Effects of CT Wall Thickness on Maximum Average WOB
HTB 1-OD, 2.5-10 ppg Fluids, $C_f = 0.50$

Figure 11 indicates that larger diameter CT would not provide adequate WOB for drilling with air in 1.125" boreholes. Increasing the CT wall as much as possible within commercially available sizes would not substantially improve these results.

Figure 11: Effects of Friction on Maximum WOB
HTB 1-OD, Air (0.6 ppg)

Figures 12-14 show *Analyzer* results for 1.00" OD x 0.087" wall CT in the 1.875" boreholes. Using the thickest wall CT available (0.109") could provide enough WOB for drilling with air in the directional boreholes for low Cf. However, the 1.00" OD CT is not stiff enough to provide adequate WOB at 2000' in the vertical borehole.

**Figure 12: Effects of Friction on Maximum Average WOB
HTB 2-OD, 2.5-10 ppg Fluids**

**Figure 13: Effects of CT Wall Thickness on Maximum Average WOB
HTB 2-OD, 2.5-10 ppg Fluids, Cf = 0.50**

**Figure 14: Effects of Friction on Maximum WOB
HTB 2-OD, Air (0.6 ppg)**

Analyzer results for case HTB 3-OD in Table 12 indicated that 1.25" OD x 0.095" wall CT would provide at least 3000 lbs WOB with 2.5-10 ppg fluids in all three 2.25" borehole trajectories for $C_f < 0.50$.

Figure 15 shows *Analyzer* results for this CT and air in the 2.25" boreholes. Using thicker wall CT could provide enough WOB for drilling with air in the directional boreholes for low C_f . However, no commercially available 1.25" OD CT would be stiff enough to drill with air in the vertical borehole.

**Figure 15: Effects of Friction on Maximum WOB
HTB 3-OD, Air (0.6 ppg)**

The *Analyzer* results presented above for HTB 3-OD suggest that 1.25" CT would be overkill for drilling in the 2.25" boreholes. Eliminating this size tubing would simplify the MBDP design and reduce the size of the CT reel. Consequently, HTB 3-1 in Table 3 presents a possible scenario with thick-walled 1.00" CT in the 2.25" boreholes.

Figure 16 shows that this combination is feasible in the directional boreholes but not acceptable for drilling vertically to 2000'. Unfortunately, 1.00" OD x 0.109" wall CT would not provide adequate WOB for drilling with air.

Figure 16: Effects of Friction on Maximum Average WOB
HTB 3, 1.00" OD x 0.109" Wall CT, 2.5-10 ppg Fluids

Based on the results presented in this section, 0.625" OD tubing is not a good candidate for the proposed CTD scenarios. For most cases, 0.75" and 1.00" OD tubing would be adequate. Using only two tubing sizes would simplify the MBDP design. Also, stepping up one size CT in the two smallest boreholes provides better hydraulic performance.

Table 13 summarizes the maximum snubbing and pulling forces predicted for 70,000 psi yield stress tubing and the cases described in Table 12. The maximum snubbing force occurs at lockup during RIH. These maximum forces set the performance criteria for the MBDP injector, Section V.A. The values in the last row of Table 13 are predicted stresses in the CT at the top of the borehole during POOH with 1000 lbs overpull at the BHA. Assuming an 80% safety factor, the minimum acceptable tubing yield stress for the worst case scenario would be approximately 27,000 psi. This means the stainless steel listed in the SOW would be suitable for the proposed drilling operations.

Table 13: Maximum Forces and Stresses at MD = 0' for Revised CT Strings

	HTB 1-OD	HTB 2-OD	HTB 3-OD	HTB 3-1
Maximum Snubbing Force (lbs)	-7890	-13,700	-18,830	-16,870
Maximum Pulling Force (lbs)	7900	13,700	18,830	16,870
Stress (psi), POOH + 1000 lbs	21,681	18,028	17,727	15,553

B. CT fatigue Life

Working life of a CT string decreases with increasing OD, increasing internal pressure, decreasing wall thickness, and decreasing reel core diameter. Figure 17 shows effects of reel core diameter on fatigue life of 1.00" OD x 0.087" wall CT. This represents a lower bound for the cases in Table 12. A "trip" means one complete cycle from the reel, RIH through the injector, POOH through the injector, and back onto the reel. The fatigue calculations assumed the MBDP does not have a guide arch. All of the CT strings evaluated in this study would survive at least 200 trips at 2000 psi internal pressure for this MBDP conceptual design.

Figure 17: Effects of Reel Core Diameter on Fatigue Life of 1.00" OD x 0.087" Wall CT

IV. MBDP HYDRAULIC PERFORMANCE EVALUATION

The SOW did not address hydraulic performance of the CT strings. However, adequate fluid flow rate is required to operate the drilling motor, remove drilled cuttings from the bit face, and transport those cuttings to the surface. The pressure loss through the CT string and CT/borehole annulus sets the lower limit for hydraulic horsepower with a given fluid and flow rate. Figure 18 is an example of this calculation for three of the CT sizes listed in Table 12 using the properties of 8.5 ppg salt water and 2500' of tubing. This figure gives a good indication of the minimum pump pressure required to achieve a given flow rate for this fluid.

Figure 18: Pressure Loss for 2500' of Tubing with 8.5 ppg Salt Water

V. MBDP CONCEPTUAL DESIGN

The physical and performance specifications outlined in the SOW suggested a miniature CT unit similar to others built by Hydra Rig of Fort Worth, TX, for trenchless drilling and cementing inside maintenance tunnels. Figures 19 and 20 show the MBDP design combining several of the components used in those earlier units with the unique features dictated by the SOW. The mud tank provides a convenient supporting structure and ballast for the MBDP in the vertical drilling mode (VDM). Anchor bolts, braces against other objects, or the transporting vehicle would support the MBDP in the horizontal drilling mode (HDM).

The typical CT unit guide arch (gooseneck) is the source of two-thirds of the fatigue damage to the tubing. Moreover, it adds considerable height to the unit and forces the separation of the reel and injector head. The design concept resulting from this study eliminates the guide arch to provide an extremely compact platform. Figures 21 and 22 show the MBDP overall dimensions in VDM, and Figures 23 and 24 show them in HDM.

The MBDP weighs approximately 6900 lbs without the mud tank and tubing. A maximum load of 1" OD x .087" wall CT increases this weight to 9130 lbs.

Figure 19: MBDP, in VDM, Side View, Main Components

Figure 20: MBDP, in VDM, Front View, Main Components

Figure 21: MBDP in VDM, Side View, Overall Dimensions

Figure 22: MBDP in VDM, Front View, Overall Dimensions

Figure 23: MBDP in HDM, Side View, Overall Dimensions

Figure 24: MBDP in HDM, Front View, Overall Dimensions

The following sections describe the other features labeled on these figures.

A. Tubing Injector

The prime mover of the MBDP is its injector, Figures 25 and 26. The injector provides the pulling/pushing force required to move the CT in a borehole. Two continuous and opposing gripper chains are the heart of the injector. Short gripper blocks contoured to match the OD of the CT or shaped like a "V" cover each chain. Hydraulic cylinders force the chains with their gripper blocks together around the CT. Variable-speed hydraulic motors drive the gripper chains, and the tensioners keep the chains taught. As the chains move linearly in the direction of the CT axis, friction between the gripper blocks and the tubing causes the CT to move at the same rate as the chains. The process resembles climbing a rope hand-over-hand. Friction is the only force supporting the CT in the injector.

Figure 25: MBDP Injector Components

Figure 26: MBDP Injector Overall Dimensions

The tubing depth counter (Figure 25) consists of a small wheel bearing against the CT and aligned to roll along its surface in the axial direction. Due to friction between the wheel and CT, the wheel rotates as the CT passes by. An encoder attached to the shaft of the wheel senses its revolutions. The data acquisition unit at the operator's console converts the wheel revolutions into linear distance the CT traveled (depth). Instrumented load pins (Figure 25) or a load cell between the injector and the adjustable frame would provide a direct measurement of the axial force applied to the CT by the injector. The total hydraulic pressure required by the injector drive motors would give a secondary indication of the injector pulling or pushing force.

The MBDP injector weighs approximately 2200 lbs and can pull or push with 17,000 lbs of force (see Table 13). Maximum running speed is 50 ft/min in each direction. The injector can operate with CT sizes 0.625"-1.25". However, the skates can retract far enough to allow passage of tools up to 2.5" OD through the injector bore. This unique feature eliminates the need to move the injector away from the borehole to work on the BHA. The injector motors require a maximum flow rate of 25 GPM of hydraulic fluid at 3400 psi pressure.

B. Adjustable Frame

The lift arms (Figures 19 and 20) on the MBDP injector frame support the injector. Hydraulic rams can position the injector at any drilling angle between vertical (down) and horizontal. Mechanical locks provide rigid support during drilling operations and transport. A manually-operated mechanism can adjust the position of the injector laterally and vertically to align it over the borehole. The injector frame can sit directly on the ground for horizontal drilling applications or on the mud tank or other suitable support structure for vertical drilling applications.

C. Tubing Reel

The CT reel assembly shown in Figures 27 and 28 is simply a storage device. The hydraulic reel drive motor has only enough power to wrap/unwrap CT onto/off the drum. The MBDP reel weighs approximately 2375 lbs empty. Table 14 shows the reel capacities and loaded weights for the CT sizes evaluated during this study.

Table 14: MBDP Reel Capacities and Weights

CT		Reel	Reel Weight (lbs)	
OD (in)	Wall (in)	Capacity (ft)*	CT Empty	CT + Water
0.625	0.049	6927	2085	2739
0.750	0.067	4811	2350	2971
1.000	0.087	2635	2231	2841
1.000	0.109	2635	2728	3274
1.250	0.095	1732	3082	4087

*Assumes 1" of freeboard

Figure 27: MBDP Reel Components

Figure 28: MBDP Reel Overall Dimensions

1. Reel Carriage and Level Wind

The MBDP reel design incorporates the tubing level wind mechanism into the reel support. A hydraulic ram moves the reel carriage (Figure 29) back and forth along the reel's axis of rotation. The level-wind serves to tightly compact the wraps of CT on the drum during pickup and to ensure smooth unwrapping during slackoff. Normally, the level-wind automatically paces the drum rotation. If necessary, the operator can override the automatic function and move the level-wind manually.

Figure 29: Reel Carriage Main Components

Figure 30: Reel Carriage Overall Dimensions

2. Reel Drive Mechanism

The reel drive mechanism consists of a hydraulic motor and sprocket connected to the reel sprocket with a drive chain. The reel drive motor also functions as a dynamic brake during slackoff to maintain tension on the CT between the drum and the injector. Blocking the hydraulic supply to and return from the drive motor serves as a static brake. During pickup, the reel drive motor applies more torque to the drum than required to pace the injector pulling speed. This excess torque keeps the CT taut and tightens the wraps on the drum. The maximum reel back tension is approximately 2000 lbs.

3. High Pressure Swivel

Figure 27 shows the high pressure swivel mounted on the side of the reel. The swivel connects the CT on the reel to external piping. The swivel is rated for continuous duty at 3000 psi pressure.

4. Reel Electrical Connection

The slip-ring shown in Figure 27 provides a rotating connection between electric cable in the CT and external wiring, such as a logging truck. The cable is terminated at a pressure bulkhead rated for a working pressure of 3000 psi. The wires from the pressure bulk head connect to the collector ring in the commutator mounted inside the reel. These electrical components are rated for 1000 V at 5 A. The commutator can rotate at 20 rpm with electrical signal and up to 100 rpm without electrical signal.

D. Borehole Surface Pressure Control

The MBDP is not designed to operate with high borehole surface pressure, but can provide up to 1000 psi back pressure on the borehole with the components shown in Figure 31 and described in the following sections.

Figure 31: MBDP Borehole Pressure Control Components

1. Bit Window

The bit window provides access to the tubing and tools below the injector and acts as a short slip joint to aid positioning the injector. Also, it provides lateral support for the CT during snubbing operations. The MBDP bit window has a working pressure rating of 5000 psi and total slip joint travel of 6".

2. Tubing Seal

The tubing seal replaces the stripper (packoff) found on typical CT units and provides a seal around the CT against the pressure in the annulus of the borehole. The seal has a working pressure rating of 1000 psi. It also functions as slips for the BHA capable of supporting up to 1000 lbs. The MBDP seal can open to a maximum ID of 2.5" to allow passage of the BHA.

3. Divertor head

The MBDP divertor head returns the drilling fluid from the borehole annulus to the flow return line. It is rated for 5000 psi working pressure.

E. MBDP Hydraulic Power Unit

The hydraulic power unit on a CT unit must simultaneously provide several fluid pressures and flow rates to the various motors and rams on the platform. Consequently, the collection of pumps, motors, accumulators, valves, and rams in the system must be

designed together to ensure the proper performance from the CT unit. Such a system design is beyond the scope of this study, but the following general specifications apply to the MBDP.

- Power Source - Diesel or electric motor providing 100 HP at 2500 rpm intermittent and 80 HP continuously at 2500 rpm
- Pumps
 - #1 22.5 gpm at 3400 psi
 - #2 13.6 gpm at 3700 psi
- Power fluids connections - flex hoses with high pressure quick connects

F. MBDP Operator's Controls

The operator's controls are necessarily an integral part of the hydraulics system. Such a system design is beyond the scope of this study. However, the controls would regulate the following functions of the MBDP.

- Injector axial force (pull/push)
- Injector running speed
- Reel back tension (dynamic braking)
- Level wind
- Skate pressure (gripper force)
- Chain tension
- Lift arms
- Tubing seal pressure

G. Mud Tank

Due to the height requirements when in VDM, the MBDP reel must be elevated to allow the injector to pivot downward on the support arms. The high snubbing forces predicted by the drilling performance analyses (see Table 13) dictate that the support structure be capable of counteracting a vertical force upward of approximately 17,000 lbs. Since typical drilling operations usually require a mud, the tank provides a convenient support structure for the MBDP (see Figure 19). The mud tank weighs approximately 3450 lbs empty and approximately 21,050 lbs with 50 bbls of water.

VI. ENGINEERING COST ESTIMATE

Table 15 lists the major components for the MBDP described in the previous sections and an engineering cost estimate for each. The costs do not include detailed engineering or production of manufacturing drawings. These would require approximately 1 manyear.

The manufacturer shown for each component has previous experience with small CT units or has built such components for other applications. They estimate the total time to build the MBDP would be three months from receipt of order.

Table 15: MBDP Components and Cost Estimate

Component	Manufacturer	Cost Estimate
Injector	Hydra-Rig	\$75,000
Reel w/frame &drive	Hydra-Rig	\$45,000
Injector Frame	Hydra-Rig	\$20,000
Bit Window	Texas Oil Tools	\$4,500
Stripper	Texas Oil Tools	\$7,000
Divertor	Texas Oil Tools	\$1,000
Power Unit	Hydra-Rig	\$45,000
Control Unit	Hydra-Rig	\$15,000
Power Fluid Hoses	Hydra-Rig	\$7,000
Drilling Fluids Piping	Hydra-Rig	\$2,000
Mud Tank	Hydra-Rig	\$16,000
Total		\$237,500

Table 16 provides contact information for the manufacturers listed in Table 15.

Table 16: Manufacturers Information

Manufacturer	Hydra-Rig	Texas Oil Tools
Contact	Randy Graves	Bryant Cardwell
Address	6000 East Berry St.	2800 North Frazier
	P.O. Box 15951	P.O. Box 2327
	Ft Worth, TX 76119	Conroe, TX 77305
Phone	(817) 457-3825	(409) 756-4800
Fax	(817) 457-3897	(409) 756-8102

VII. APPENDIX A - STATEMENT OF WORK (SOW)

"MICRO BOREHOLE DRILLING PLATFORM"
STATEMENT-OF-WORK
October 28, 1996

1. OBJECTIVE

The objective of this STATEMENT-OF-WORK is to complete a feasibility investigation and develop a conceptual design, performance specification, a primary components list and preliminary layout drawings for a coiled-tubing microdrilling surface platform. The deliverables will be used by the University (LANL) to develop and issue a SPECIFICATION AND REQUEST FOR PROPOSAL AND QUOTATION for the fabrication of a portable, coiled-tubing, drilling platform.

This platform, a coiled-tubing with an internal telemetry cable installed, a bottom-hole drilling assembly, and a downhole steering tool will be assembled to demonstrate the feasibility of: (1) drilling 1-inch to 2-1/2-inch diameter directional/horizontal Microboreholes to vertical depths of 2000 ft or horizontal reach of 500 to 1000-ft in firm soils, soft to hard rocks, and concrete; and (2) preparing the boreholes for instrumentation emplacement. Commercial drilling systems that are capable of directional drilling in very hard rock are presently sized to drill 3 5/8-inch and larger holes. Trenchless utility installation technology is presently capable of directional drilling holes as small as 1 7/8-inch in some rock types and soils. This project will identify critical components of a conceptual microdrilling system and demonstrate the feasibility of adapting oil field drilling and trenchless boring technology to produce a micro-drilling system that can drill 1 -inch to 2 1/2-inch diameter directional holes in hard rock and meet our sponsor's specified equipment size and foot print requirements.

2.SCOPE OF WORK

2.1.Coiled-tubing Drilling Parametric Investigation.

The subcontractor shall use an oil industry accepted coiled-tubing loading, stress and buckling analysis code to conduct a feasibility analysis for drilling (1) river-crossing type trajectories up to 500-ft-long in stable soils and hard rock and (2) near vertical holes to 2000 ft. The drilling system to be modeled shall include a near bit, pneumatic or hydraulic powered, positive displacement motor will rotate the drilling assembly. The drilling platform will include a tubing injector that will insert, extract, and propel the drilling assembly to develop the required weight-on-bit during drilling. Pressure control equipment will be sufficient to divert the drilling fluid return into atmospheric tanks or an air return and cuttings to a low-back pressure (< 10 psig) separator. The following input parameters will be used to conduct the analysis.

2.1.1 Hole diameters, Coiled-tubing, Bottom-hole Assembly

2.1.1.1 1.125-in bore with 0.625-in OD tubing, 0.875-in OD 75-in-long PDM, 1.00-in OD by 0.875-in ID by 10-ft long non-magnetic drill collar, and 1.000-in OD by 0.500-in ID by 1-ft-long x-over.

2.1.1.2 1.875-in bore with 0.750-in OD tubing, 1.500-in OD 130-in-long PDM, 1.750-in OD by 1.500-in ID by 10-ft long non-magnetic drill collar, and 1.750-in OD by 0.616-in ID by 2-ft-long x-over.

2.1.1.3 2.25-in bore with 1.000-in OD tubing and 1.500-in OD 130-in-long PDM, 1.875-in OD by 1.625-in ID by 10-ft long non-magnetic drill collar, and 1.250-in OD by 0.866-in ID by 2-ft-long x-over.

2.1.2. Coiled-tubing material specifications.

2.1.2.1. A-606 Type 4 carbon steel, 70,000 psi yield strength

2.1.2.2. ASTM A269 304 stainless steel, 30,000 psi yield strength for low cycle use, less than 10 insertion cycles at 1000 psi maximum internal pressure

2.1.3. Friction coefficient. (between rock and tubing or bottom-hole-assembly)

2.1.3.1. Air drilling - 0.6, 0.9, & 1.2

2.1.3.2. Water (drilling fluid) - 0.2, 0.4, & 0.6

2.1.4. Weight-on-bit (WOB). 100 to 2000 lb/in² of hole area for drag bit drilling.**2.1.5. Well trajectories.**

2.1.5.1. Initial borehole inclination 0°(vertical) to 90°(horizontal)

2.1.5.2. Maximum curvature 36°deg/100 ft

2.1.5.3. Determine the maximum WOB at buckling for the following trajectories for the hard rock coefficients of friction specified in paragraph 2.1.3.

2.1.5.3.1. Straight, near vertical hole to 2000 ft. Maximum inclination = 3'

2.1.5.3.2. Worst case trajectory (circle with radius = 318 ft, 18°/100 ft)

Measured Depth	Vertical	Horizontal	Inclination
0 ft	0 ft	0ft	45 deg
50 ft	32 ft	37ft	54 deg
100 ft	59 ft	81ft	63 deg
150 ft	78 ft	127ft	72 deg
200 ft	89 ft	175ft	81 deg
250 ft	93 ft	225ft	90 deg
300 ft	89 ft	275ft	99 deg
350 ft	78 ft	323ft	108 deg
400 ft	59 ft	369ft	117 deg
450 ft	32 ft	412ft	126 deg
500 ft	0 ft	450ft	135 deg

2.1.5.3.3. Worst case trajectory (circle with radius = 477 ft, 12°/100 ft)

Measured Depth	Vertical	Horizontal	Inclination
0 ft	0 ft	0 ft	60 deg
50 ft	23 ft	45 ft	66 deg
100 ft	41 ft	91 ft	72 deg
150 ft	54 ft	139 ft	78 deg
200 ft	61 ft	189 ft	84 deg
250 ft	64 ft	239 ft	90 deg
300 ft	61 ft	289 ft	96 deg
350 ft	54 ft	338 ft	102 deg
400 ft	41 ft	386 ft	108deg
450 ft	22 ft	433 ft	114 deg
500 ft	0 ft	477 ft	120 deg

2.1.6. Maximum available motor torque. 150 ft-lb. Limit motor torque to 80% of nominal yield torque of the coiled-tubing.**2.1.7. Density of drilling fluid.** 0 to 10 lb./gal**2.1.8. Maximum fluid or air injection pressure.** At least 2500 psi.

2.2. Conceptual Design and Performance Specification

The subcontractor shall use the results of the (2.1) Parametric Investigation and other calculated and rock drilling test results provided by the University (LANL) to develop a conceptual design for a skid mounted, portable, coiled-tubing, drilling platform and performance specification for major components. The design should develop the smallest platform feasible with off-the-shelf components.

2.2.1. Reel size and mounting details

- 2.2.1.1. Reel sized to carry 2100-ft of 3/4-in OD tubing or 3000-ft of 5/8-in OD tubing.
- 2.2.1.2. Swivel for 1000 psig air and/or fluid input into the coiled-tubing on the reel
- 2.2.1.3. Bearing and frame requirements for standard and reel powered tubing injectors
- 2.2.1.4. Reel drive unit with pneumatic or hydraulic motor
- 2.2.1.5. Fixtures to attach coiled tubing to reel and pressure fitting to extract telemetry cable from coiled tubing and route it to the commutator
- 2.2.1.6. Commutator for telemetry wire inside coiled-tubing

2.2.2. Tubing injection platform

- 2.2.2.1. Adjustable mounting platform for slant-hole drilling
- 2.2.2.2. Tubing injector and power source
 - 2.2.2.2.1. Conventional tubing grip injector (pneumatic or hydraulic) or
 - 2.2.2.2.2. Reel powered injector with pneumatic or hydraulic rotary motor drive
- 2.2.2.3. Goose neck radius, maximum bend and mounting detail
- 2.2.2.4. Divertor head, tubing seal, platform to earth (floor or wall) seal, and outlet pipe for annular flow line
- 2.2.2.5. Bottom-hole-assembly makeup/insertion and removable/breakdown fixture Assume that the maximum length bottom-hole-assembly component is 130-in. (bit, PDM, and x-over to coiled-tubing end fixture).

2.2.3. Fluid inlet fluid return system. Fluid (air) inlet and fluid (air) outlet fittings shall be permanently mounted, in close proximity, near an edge of the platform. Fluid handling equipment, pumps, and compressors will be on auxiliary platforms and are not part of this investigation and specification.

2.2.4. Power supply. All equipment on the drilling platform shall be driven by a single external power supply which may be hydraulic, electric, or pneumatic. The subcontractor shall specify power requirements of each component on the drilling platform.

2.2.5. Control Unit. A hydraulic, electric, or pneumatic control unit to regulate tubing insertion, drilling thrust maintenance, tubing extraction and parking will be included in the conceptual design.

2.2.6. Auxiliary Equipment. The generator or hydraulic or pneumatic power unit will be installed on an **auxiliary platform** along with pumps and/or compressors to inject drilling fluid and/or air into the coiled tubing and pits, separators, or filters on the return fluid outlet. **Auxiliary equipment is not part of this conceptual design and component specification.**

2.3. Layout Drawing and Component List

The subcontractor shall use the results of the (2.1) Parametric Investigation and (2.2) Conceptual Design and Performance Specification to develop a layout drawing of the drilling platform for the preferred tubing injection mode with recommended components identified.

2.3.1. Layout Drawing. The drawing shall include three orthogonal views including rough dimensions ($\pm$ 1-inch) of the relative position of major components and the skid and support structure.

2.3.1.1. Skid frame

- 2.3.1.2. Tubing injection (adjustable slant-hole) platform
 - 2.3.1.2.1. Gooseneck mount
 - 2.3.1.2.2. Injector
 - 2.3.1.2.3. Divertor head, tubing seal, earth seal, and outlet pipe
- 2.3.1.3. Reel platform
 - 2.3.1.3.1. Bearings and rotation (drive) shaft
 - 2.3.1.3.2. Swivel
 - 2.3.1.3.3. Commutator
- 2.3.1.4. Reel
 - 2.3.1.4.1. Tubing attachment fixture
 - 2.3.1.4.2. Cable insertion fixture
- 2.3.1.5. Piping layout
- 2.3.1.6. Tubing injection control schematic

2.3.2. Component List. A component list of recommended and alternate, if identified, off-the-shelf components that are suitable for the drilling platform shall be attached to the layout drawing. The component list shall include:

- 2.3.2.1. Source list - address, phone, fax, and contact identified.
- 2.3.2.2. Engineering cost estimate for the recommended components
- 2.3.2.3. Estimated delivery time from date of order

3. DELIVERABLES

- 3.1. Parametric Analysis - Draft Report**
- 3.2. Conceptual Design and Performance Specification - Draft report**
- 3.3. Final Report.** Shall include (1) Layout Drawings, (2) Component List and Specifications, (3) Engineering Cost Estimate, and (4) Delivery Times

4. SCHEDULE

Completion Milestone

- 8/15/96 Draft Report - Parametric Investigation
- 9/1/96 Draft Report -Conceptual Design and Performance Specifications
- 9/15/96 Layout Drawing and Component List
- 9/30/96 Final Report