Horizontal Directional Drilling (HDD) Systems for Pilot Bore Drilling in Mixed Soil Conditions and Rock

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Abstract

Several systems have been developed for, or adapted to, horizontal directional drilling (HDD) that successfully directionally drill through mixed soil conditions and rock. These include slant face rock bits and rotary steerable HDD systems. Steerable downhole hammers are more suited to continuous, harder rock.

Rotary steerable systems fall into two main groups: (1) downhole motors driven by the drilling fluid (mud motors), and (2) various types of drill string driven downhole assemblies. These rotary steerable systems are described and compared. The latter group is sometimes driven by a single-member drill string, but more often it is driven by the inner member of a dual-member drill string while the outer member provides steering control. Case study examples are also included. As a result, the project owner, engineer and contractor will have better knowledge of HDD equipment options suitable for product installations in difficult ground conditions.

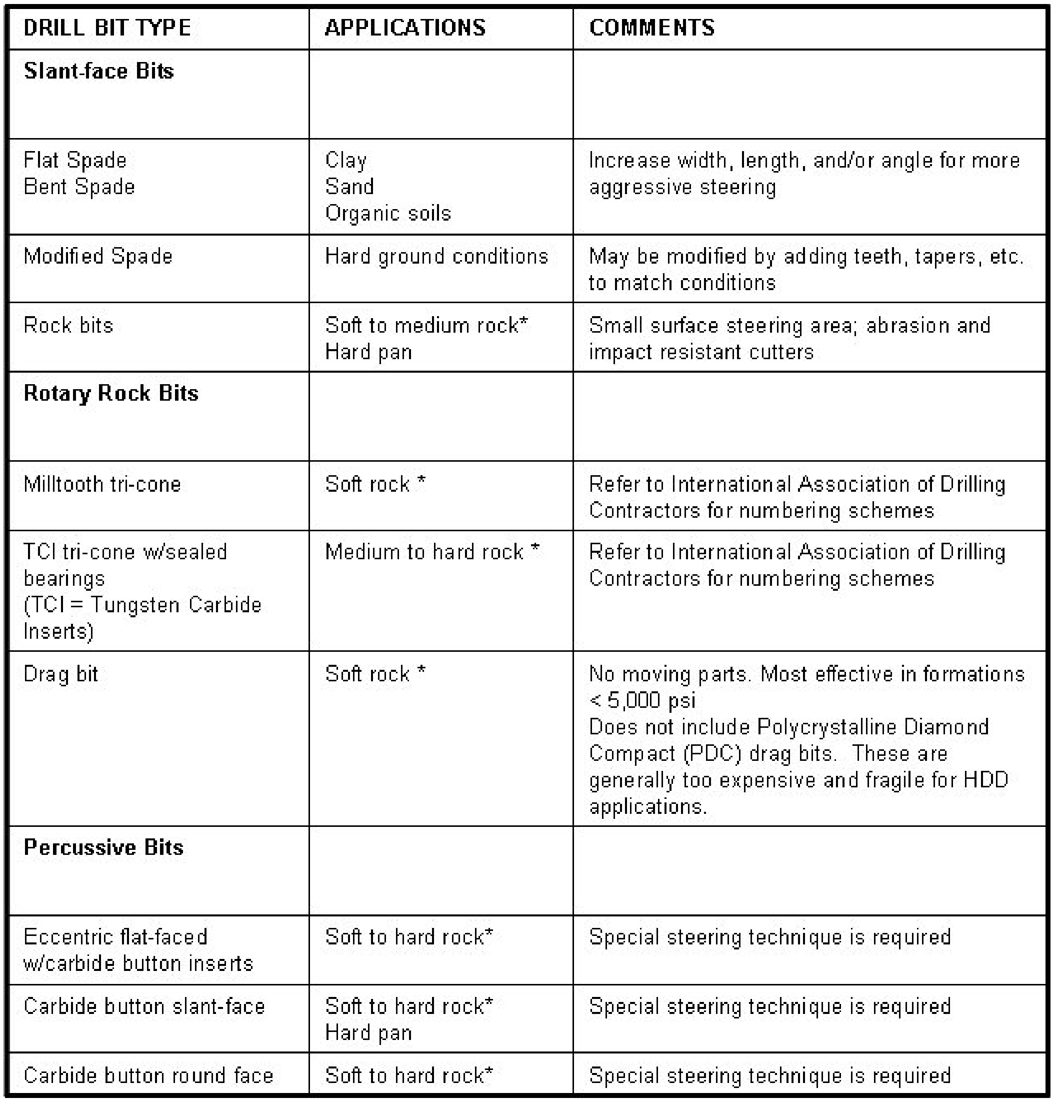
The importance of site investigation at the design and pre-bid stage of a project is stressed. Numerous references are cited. Important factors in selecting rotary rock bits for HDD applications are given, along with a bit selection chart.

Introduction

Variations in soil conditions often exist along a proposed path for near-surface placement of underground pipes and cables. Gravel and cobble may be interspersed with the soil. Boulders, layers of rock or cemented sand (caliche) may be present. Such variations can pose problems for conventional open-cut excavation and for trenchless installation techniques, particularly if not expected. Adequate site investigation at the design and pre-bid stage of a project is the proper way to reduce uncertainty and risk. This step and others important in the preconstruction phase of a project are well documented in the literature (Bayer 2005, Chapter 3; Burnam , et.al. 2001; Conroy, et.al. 2002; Dorwart and Ariaratnam 2008; Francis, et.al. 2007; HDD Consortium 2008, Chapter 4; Kwong 2002; Proulx and Young 2008; Strater, et.al. 2006 and 2007; and many others). Appropriate installation techniques and tooling can then be specified or selected.

In recent years, several types of systems and downhole tooling for Horizontal Directional Drilling (HDD) machines have been developed, or were adapted from oil and gas drilling technology, which are capable of productive drilling in mixed soil conditions and rock. The working tools (bits) potentially suitable for such conditions are listed as slant-face rock bits, rotary rock bits and percussive bits in the following table reprinted with permission of the North American Society for Trenchless Technology (NASTT) from the reference: (HDD Consortium 2008). Slant-face rock bit tools and steerable jetting assemblies that utilize rotary rock bits are described in the literature (Gunsaulis 2006; and many others) and will not be discussed herein.

Table A: HDD Drill Bit Types and Application Guidelines (Table 3-2 from HDD Consortium 2008)



DRILL BIT TYPE	APPLICATIONS	COMMENTS
Slant-face Bits		
Flat Spade Bent Spade	Clay Sand Organic soils	Increase width, length, and/or angle for more aggressive steering
Modified Spade	Hard ground conditions	May be modified by adding teeth, tapers, etc. to match conditions
Rock bits	Soft to medium rock* Hard pan	Small surface steering area; abrasion and impact resistant cutters
Rotary Rock Bits		
Milltooth tri-cone	Soft rock *	Refer to International Association of Drilling Contractors for numbering schemes
TCI tri-cone w/sealed bearings (TCI = Tungsten Carbide Inserts)	Medium to hard rock *	Refer to International Association of Drilling Contractors for numbering schemes
Drag bit	Soft rock *	No moving parts. Most effective in formations < 5,000 psi Does not include Polycrystalline Diamond Compact (PDC) drag bits. These are generally too expensive and fragile for HDD applications.
Percussive Bits		
Eccentric flat-faced w/carbide button inserts	Soft to hard rock*	Special steering technique is required
Carbide button slant-face	Soft to hard rock* Hard pan	Special steering technique is required
Carbide button round face	Soft to hard rock*	Special steering technique is required

* Soft rock: <5,000 psi (35 MPa), Medium rock: 5,000 – 15,000 psi (35 to 100 MPa), Hard rock: 15,000 – 30,000 psi (100 to 200 MPa); Very hard rock: > 30,000 psi (200 MPa)

Percussive bits and associated steerable downhole hammers are described in (Gunsaulis 2006; and HDD Consortium 2008). These systems can be more productive than purely rotary drilling systems when extremely hard rock is encountered. Steering is accomplished either by a bend (bent sub) in the downhole assembly, by a slant-face on the bit, by an eccentric shaped (elephant's foot) bit, or by a combination of such features. High volumes of compressed air are generally utilized to power the hammer. Even higher volumes are needed to clear cuttings from the borehole. Thus such directional drilling systems may not be able to complete a bore through variable soil conditions (HDD Consortium 2008).

The rotary rock bits listed in the above table are certainly capable of drilling through mixed soil conditions and rock. How productive and steerable they may be is dependent upon the overall system configuration that drives them. Description and comparison of such systems are the focus of this paper.

Before going there, it is instructive to include a rotary bit selection chart (Figure 1) adapted from one furnished courtesy of INROCK® (Agnew 2008). Rock hardness, measured as Unconfined Compressive Strength (UCS), is shown in both English (pounds per square inch, psi) and metric (Mega Pascals, MPa) units. A bit comprised of milled-tooth roller cones is designated by "M-T" in the chart, while "TCI" designates tungsten carbide insert roller cones. IADC bit codes are found in the Drilling Design Handbook published by the International Association of Drilling Contractors (http://iadc.org/). The drillability scale at the bottom of the chart is an attempt to correlate drilling difficulty with MOHs Hardness and UCS of rock – the higher the number the more difficult to drill.

Rotary rock bits for HDD applications differ in design from those intended for oil field applications, and will generally be more productive and cost-effective. HDD is a “beating and banging” environment when drilling through mixed conditions such as broken and chunk rock. And the rock is often more abrasive than found in the mostly continuous, “finesse” rock drilling environment of the petroleum industry. Leg and added gage protection are standard on typical HDD rotary rock bits, whereas those features may be optional in bits designed for other applications. Bit nozzles should be sized for the intended drilling fluid flow rates. The flow rate must be sufficient to clean cuttings from the virgin rock face and convey them out of the borehole. Excessively restrictive nozzles will degrade performance when a downhole motor is employed (Lahay 2007).

As rock hardness increases, slower rotational speed and greater thrust on the bit are recommended. “Dwell time” of each TCI insert’s contact with the rock is extremely important when drilling hard rock. Adequate time must be allowed for delivery of sufficient energy to cause localized failure of the rock (Lahay 2007).

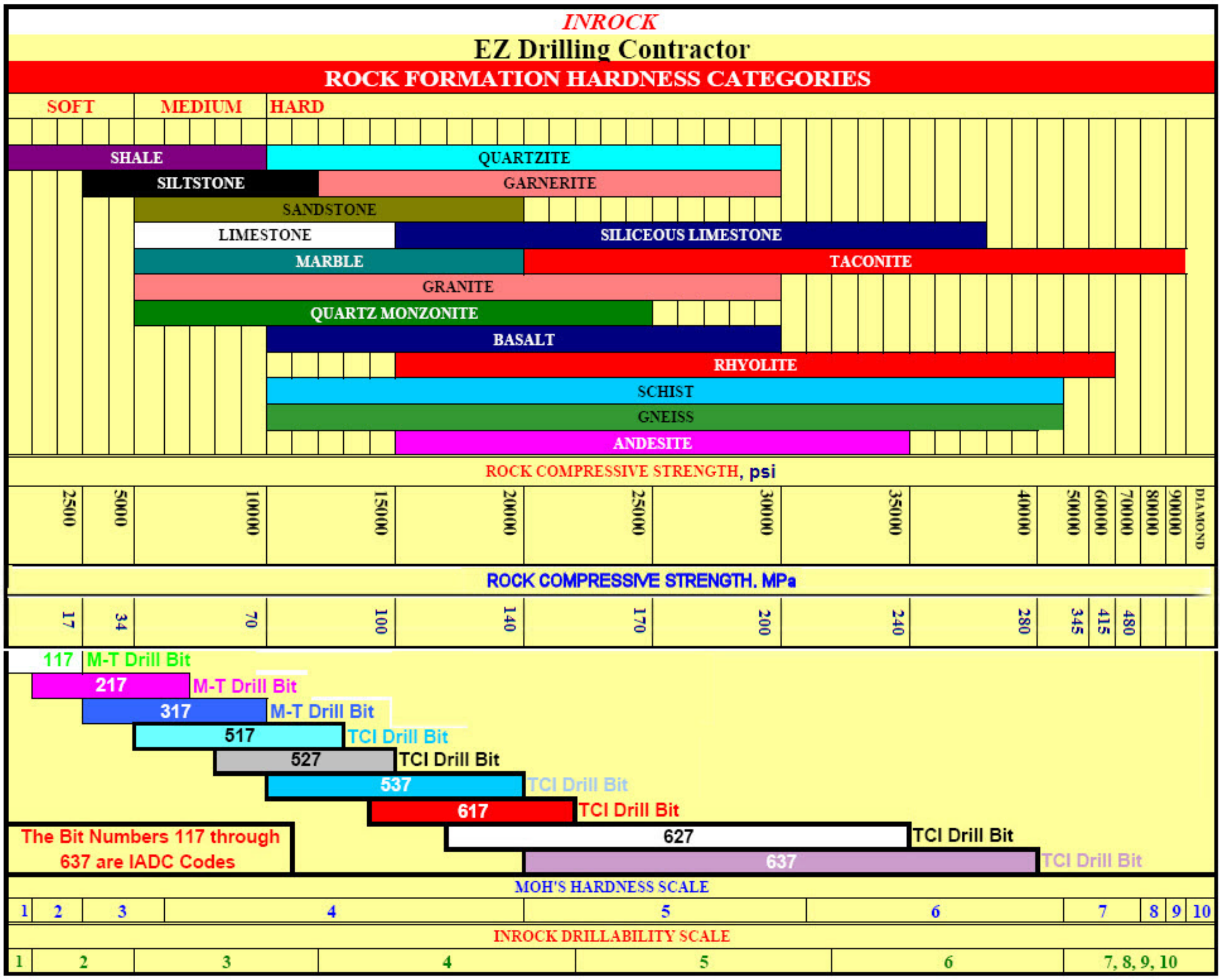


Figure 1: Bit Selection Chart for Rotary Drilling of Rock (Agnew 2008)

Rotary Steerable HDD Systems

In HDD applications, rotary bits are driven either by rotation of the drill string or by a downhole drilling-fluid-powered motor – typically referred to as a “mud motor”. A good overview of these systems is given in (HDD Consortium 2008). Some of the high points therein – directly quoted with permission – are shown as indented text below:

Mud Motor:

Downhole motors have been successfully utilized in HDD applications since the 1970s and are typically variations adapted from the oil field drilling industry. They are particularly suitable for under river crossings and other extended reach bores that require large drill rigs. In recent years, lower flow mud motors have been developed for mid-sized HDD drill rigs. The HDD Good Practices Guidelines, 3rd Edition, 2008 contains the illustration below and says the following about mud motors:

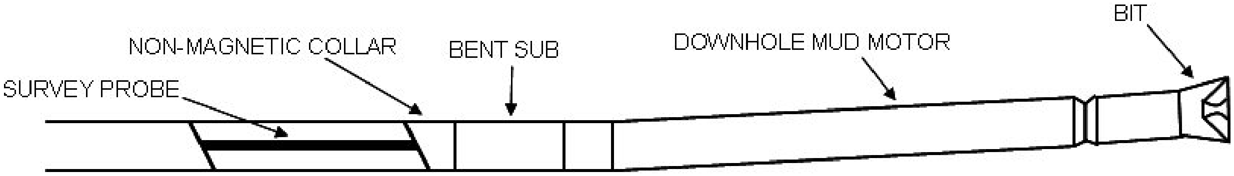


Figure 2: Mud Motor Bottom Hole Assembly with Wireline Tracking System (HDD Consortium 2008)

> …important factors for HDD applications are the output torque and fluid volume requirements. Length is also important, as the tracking equipment is located in the drill string as much as 8m (26 ft) behind the drill bit…
>
> …operational considerations such as distance from the bit to the steering tool, bend angle, fluid volume, off-bottom pressure, stall pressure, operating pressure (about 100 psi [690 kPa] less than stall pressure), and differential pressure[1] (operating pressure minus off-bottom pressure) are important for maximizing tracking accuracy, penetration rates and tooling life. Manufacturers should be consulted for advice on these matters.
>
> Directional control with mud motors is attained by using a maximum 3 degree bend … about 1.5 meters (5ft) behind the bit … the bend is oriented in the desired direction and the entire assembly is pushed to attain the steering corrections while only the bit rotates. The drill string and bit are rotated and pushed for drilling straight.
>
> - For softer formations (<15,000 psi [100 MPa]): choose a motor with higher speed/lower torque capabilities
> - For harder formations (>15,000 psi [100 MPa]): choose a motor with higher torque/slower speed capabilities (HDD Consortium 2008)

The motor driven bit should be large enough to create sufficient annulus area to clean cuttings from the borehole, but small enough to create a borehole that maintains the ability of the downhole assembly to properly steer. For instance, with a 4¾-inch (120 mm) diameter motor, the preferred bit diameter is in the range of 6½ to 6¾ inches (165to 171 mm) (Bueno 2008). The closer the bit size is to the motor outside diameter, the shorter the turning radius achieved from a given degree bent housing (McKenney 1998).

A mud motor is more efficient near its maximum flow specification. It should be matched to the deliverable mudflow of the drilling fluid circuit without overtaxing the mud pump. A pressure fed (pre-charged) mud pump may have a volumetric efficiency of 96% or more, depending upon viscosity of the mixture being pumped.[2] But this can drop to 50% or less if air is entrained by the system utilized to clean and recycle the drilling mud. The drill string and other piping in the drilling fluid circuit must be adequately sized or pressure losses will downgrade motor performance. That includes the sizing of nozzles in the bit (Agnew and Watson 2001).

Additional distinctive aspects of a mud motor drilling system that can limit its application are:

- The downhole assembly cannot be sharply steered because of its length and stiffness.

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[1] The amount of thrust (weight on bit) to apply with the drill string for optimum drilling rates is monitored by differential pressure (McKenney 1998). Some motors are capable of 600 to 700 psi (4140 to 4830 kPa) differential pressure, although they may not last as long in normal use at that pressure. A more normal range for differential pressure would be 150 to 300 psi (1030 to 2070 kPa) (Agnew 2008).

[2] A volumetric efficiency (VE) of this level requires a well maintained mud pump that is adequately pre-charged by the mud mixing system. High viscosity drilling fluid can drop VE into the range of 85 to 90%. Inadequate pre-charge can subtract 10 points from VE (Coles 2008).

- The tracking electronics may be 20 ft (6 m) behind the bit.[3] This usually causes an inexperienced drill operator to overreact and drill an S-curved pilot hole (Bueno 2008).
- Low efficiency of the mud motor limits available downhole horsepower and requires very high mud flows.
- High flow rates and pressures required for effectively driving the bit can erode the borehole or lead to undesired drilling fluid returns on the ground surface or into a body of water (commonly referred to as a "frac-out"). Operating parameters must then be reduced, but this negatively affects drilling performance (Albert, et.al. 2005).
- Equipment for capturing and reclaiming high volumes of drilling fluid are a necessary, added expense.
- A larger drilling machine and drill string is needed – compared to other drilling techniques – to accommodate the high flow rates needed for productive drilling. Job site space available for the equipment "spread" may be a limiting factor.
- Torque reaction of the motor creates torsional wind-up in the drill string. This wind-up increases with distance drilled, and must be compensated for in the steering mode or the bore will veer off the desired path.

Drill String Driven Steerable Downhole Assemblies: (excerpts from HDD Consortium 2008)

This type of system is commonly referred to as a Mechanical Downhole Motor because the drill bit is rotated continuously via the drill string. Some systems utilize a conventional, single-member drill string while others have a dual-member drill string. "Dual-member" refers to one drill string being inside another. The inner drill string generally consists of slip-joint connected solid rods or pipes, nested inside sections of the outer drill string. These slip joints make up automatically when the tool joints of the outer pipes are threaded together. The broad application range of these systems has changed the industry [by providing effective rock drilling capability on much smaller HDD units].

A dual-member drill string requires a specialty drill rig having dual top drives, to separately control rotation of each drill string. The steerable downhole rotary drilling assembly is much like that of a mud motor, but without a fluid-driven power section. This allows the housing to contain the tracking transmitter, in addition to supporting bearings for the rotating bit as illustrated in … [Figure 3]. Thus the tracking transmitter is closely positioned behind the bit, providing more timely indication of steering response than possible with most mud motors. But presence of the inner drill string prevents use of wireline tracking systems. The bit (usually a tri-cone bit) is continuously rotated by the inner drill string. The outer drill string member is used to control steering, by orienting the bent sub or bent housing in the proper direction. Straight drilling is accomplished much like a mud motor, by slowly rotating the outer pipe.

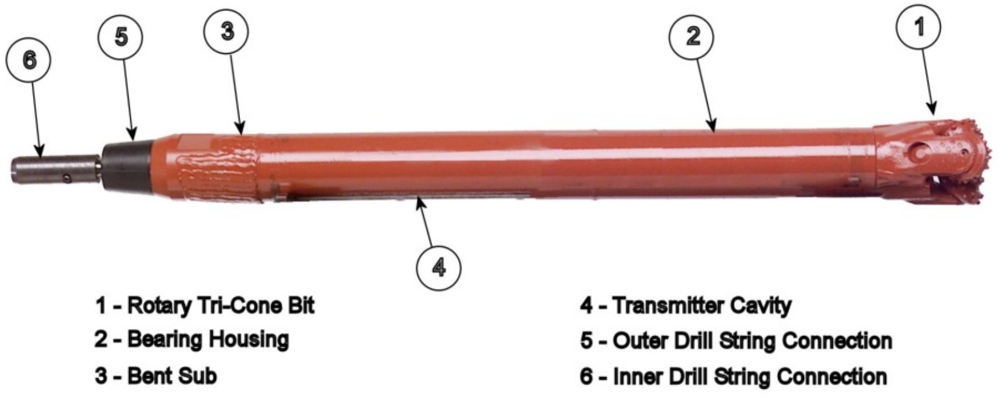

Figure 3: All-Terrain Steerable Drilling Assembly [Figure 3-14 in HDD Consortium 2008]

… Inefficiencies of drilling fluid pumps and the downhole mud motor and pressure loss from [larger volume] fluid flowing through multiple tool joints are not factors with drill string driven systems. Greater torque can be applied to the bit than with comparable diameter mud motors, which results in greater productivity in drilling the pilot bore. Only the drilling fluid flow rate needed to clear cuttings from the hole is pumped. Thus, fluid

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[3] At least one mud motor is now available with tracking electronics located closer to the drill bit (Anon. 2003).

> requirements are substantially lower and the cleaning system can be much smaller, or possibly be replaced with a vacuum system. Drill string driven systems are effective for bores in soft to hard rock. They are especially advantageous where limited work space precludes use of a large rig and fluid systems needed for driving a mud motor (HDD Consortium 2008). [They are also advantageous where frac-out is especially critical to the environment. Lower drilling fluid flow rates and pressures associated with drill string driven tools reduce the potential of inadvertent returns to the surface while drilling the pilot bore.]

Dual-member drill string rotary drilling systems are now in their third generation of HDD system evolution. The downhole assembly pictured above is current technology. The initial downhole assembly is described in (Brotherton, et.al. 1996). The second generation dual-member drill string and top drives are described in (Deken and Sewell 1997). Substantial improvements have been made since the original model was introduced in 1995 (Moore 2001). Project engineers and planners in industries other than those related to utilities are beginning to recognize the versatility and capabilities of this type of HDD system (Griffin 2006). Such a drill unit is pictured below.

Figure 4: Ditch Witch® JT4020AT (All Terrain) HDD System

Single-member drill string rotary HDD systems occasionally include the utilization of very expensive oil field downhole assemblies (Wichmann 2005). Sideways bias in the desired direction is automatically programmed to be applied to the bit via one of three radial steering pads while the drill string rotates. Two less sophisticated single-member drill string rotary drilling systems for mixed soil conditions and rock are:

(1) A de-clutchable downhole bearing housing that sideways biases the drill bit: De-clutching is generally accomplished by pushing the drill string forward with respect to the housing. This system is always in “steering mode” while drilling. Straight drilling is accomplished by alternating intervals of opposite steering. An interference fit in the borehole must hold the housing in the desired steering orientation. Thus practical application of this drilling system is limited to non-varying hard soil or rock. (HDD Consortium 2008; Morris and Heims 2000)

(2) A downhole bearing assembly containing an overrunning clutch, mounted to the drill string via a bent sub: Continuous rotation of the drill string causes the downhole assembly and bit to rotate as a unit, drilling a straight borehole. That hole diameter is somewhat larger the bit diameter because the bent sub puts continual sideways bias on the rotating bit. To cause the bit to deviate off a straight path (steer the bore), the drill string is oscillated repetitively through a partial revolution (steering arc). During reverse rotation of the drill string, the overrunning clutch disengages the drill bit from the drill string. Thus the bit is intermittently rotated in a clockwise direction (as viewed looking downhole from the drill rig) – arc segment by arc segment. An automated control system has been devised to repetitively operate the spindle drive in this oscillating manner. The steering arc is preferably at least 60 degrees, but not more than 180 degrees (Albert, et.al. 2005). Because of this incremental rotation of the bit, drilling productivity is greatly reduced when steering a bore segment. Both the drill string and the downhole bearing housing are being oscillated back and forth over the steering arc, which increases their external wear compared to a dual-member drill string system.

Because of the stated limitations of single-member drill string rotary steerable drilling systems, they will not be considered further herein.

System Comparisons

For the most part, drill string driven steerable downhole assemblies are available on drill units of pull-back capability less than 100,000 lb (445 kN). The largest commercially available dual-member drill string HDD machine is the Ditch Witch® JT4020AT shown in Figures 4, 5 and 7. This All Terrain (AT) system can productively drill and steer through almost all soil types and rock without changing downhole tools (Griffin 2002a). Its operating parameters will be compared to an example mud motor drilling system on a JT8020 drill unit having two times greater pull-back capability. This choice is made, in part, because these two HDD machine configurations have drilled 18,000 psi (124 MPa) rock at comparable rates of production – 1¼ feet/minute (0.38 m/min) – in short range drill-off tests. Secondly, a smaller drill unit may have too restrictive a drilling fluid flow path for effective utilization with a mud motor large enough to cut the 6½-inch (165mm) minimum pilot bore of the JT4020AT.[4]

Selected operating parameters of these two drill units are given in Table B.[5]

Table B: Selected Operating Parameters for Two Drilling Systems

	JT8020		JT4020AT	
Selected Operating Parameters	English	Metric	English	Metric
Drill Unit Pullback Capability	80000 lb	356 kN	40000 lb	178 kN
Engine Gross Power Rating	261 Hp	195 kW	190 Hp	142 kW
Drill Pipe Tool Joint Outside Diameter	4 in	102 mm	4.13 in	105 mm
Drill Pipe Outside Diameter	3.62 in	92 mm	3.62 in	92 mm
Drill Pipe Length per Joint	14.75 ft	4.5 m	14.25 ft	4.34 m
Spindle Speed, max	210 rpm	210 rpm	240 rpm	240 rpm
Spindle Torque, max	10000 lb-ft	13600 kN	5000 lb-ft	6800 kN
Inner Spindle Speed, max			250 rpm	250 rpm
Inner Spindle Torque, max			2000 lb-ft	2700 kN
Mud Pump Max Output Flow @ 100% VE	230 gpm	870 Lpm	120 gpm	450 Lpm
Mud Pump Max Output Pressure	1000 psi	69 bar	1300 psi	90 bar
Mud Pump Volumetric Efficiency (VE)[6]	85%	85%	85%	85%
Mud Pump Output Flow @ 85% VE	196 gpm	740 Lpm	102 gpm	386 Lpm
Percentage of Mud Flow Utilized in Pilot Bore	100%	100%	15%	15%
Mud Pump Mechanical Efficiency[7]	90%	90%	85%	85%
Mud Pump Hydraulic Drive Efficiency[8]	80%	80%	80%	80%
Max Mud Pump Pressure Utilized in Pilot Bore	1000 psi	69 bar	500 psi	34 bar
Required Mud Pump Input Power for Pilot Bore	186 Hp[9]	139 kW	6 Hp	5 kW
Mud Pump Output Power @ 85% VE	114 Hp[10]	85 kW		

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[4] Contractors have long had the opinion that a drill rig with at least 30,000 to 50,000 lb (133 to 222 kN) pull-back is needed to drill rock for utility work (Griffin 1997).

[5] Detailed specifications are available on the Internet at http://ditchwitch.com/

[6] Estimated VE when pumping a "typical" drilling fluid mixture, based on footnote #2.

[7] Mechanical efficiency taken from pump manufacturer's product specifications.

[8] A hydraulic pump and motor drive system can have an efficiency ranging from 60% to 80%. The selected value of 80% will be too kind in most instances.

[9] Calculated from (230 gpm x 1000 psi) / (1714 x mech. eff. x hyd. eff.) = 186 Hp.

[10] Calculated from (196 gpm x 1000 psi) / 1714 = 114 Hp.

The mud pump flow rate, pressure and input power tabulated above for the JT8020 are based upon an example mud motor drilling system analysis given in Appendix A. Note how much smaller these requirements are for the JT4020AT drill string driven system – e.g., 6 Hp (5 kW) versus 186 Hp (139 kW) required from the engine to drive the respective mud pumps. In actuality, all of the latter engine power is not taken until the pilot bore extends about 270 feet (82 m) beyond the distance indicated in the title of Table C below. But in either case the difference is huge!

The calculated efficiency of the JT8020 mud motor drilling system 500 ft (152 m) into a pilot bore is summarized in Table C (Table 3 from Appendix A). Not included here is the energy expended in recycling the drilling fluid. This support system is almost always needed as a companion to a mud motor drilling system (Griffin 2002b). Thus hundreds of horsepower (kW) expended on the surface delivers only a small amount of power at the downhole bit. The analysis also showed that this particular mud motor drilling system most likely cannot drill 1000 ft (304 m) pilot bores. Larger systems are, of course, capable of drilling well beyond that point. But our purpose here is to compare two types of drilling systems having somewhat similar drilling capability.

Table C: Mud Motor Output Power and Drilling System Efficiency 500 ft (152 m) into a Pilot Bore

Parameter	English	Metric
Motor Output Torque	1200 lb-ft	1625 Nm
Motor Output Speed	95 rpm	95 rpm
Motor Output Power	21.7 Hp	16.2 kW
Mud Pump Input Power	160 Hp	120 kW
Drilling System Efficiency	13.5%	13.5%

As with a mud motor drilling system, a drill string driven bit can be intermittently stalled by the formation being drilled if operated too close to its drive system ratings. Rapid release of that torque build-up can be damaging to the drill bit and other system components. The amount of thrust applied to the bit (weight on bit) via the outer drill string must be held at an appropriate level for the soil and rock conditions being drilled, and adjusted as conditions change along the borepath. A suggested starting point for torque input to the inner drill string is 1300 lb-ft (1760 Nm), which is 65% of the rated value. Sufficient measurements have not been made to determine frictional losses of the inner drill string rotating inside the outer drill string. Certainly, these losses will increase with distance drilled. Eventually torque available at the bit will diminish to the point where productivity becomes unacceptably low. However, the JT4020AT has successfully drilled in excess of 1000 ft (305 m) numerous times and has gone over 1500 ft (460 m) in some cases. These details are reported in following case histories.

Actual performance indicates the JT4020AT drilling system can out distance a mud motor drilling system on a HDD machine having twice the pull-back capability. Low flow rates of drilling fluid when drilling the pilot bore may also reduce the size or need of a recycling system – if backreaming enlargement of that borehole is not necessary. Smaller and less equipment "spread" on the drill site offers an advantage to this system in congested areas.

Sample JT 4020AT Case Histories and Performance Summaries

Wake Island (Griffin 2006)

Some of the most complex HDD applications are to install shore landing systems to shield and protect undersea cables from powerful ocean forces. Such a project was conducted in 2005, to install a near-shore cable protection system for a US Air Force Hydroacoustic Data Acquisition System (HDAS) monitoring station on Wake Island – part of a worldwide network to detect foreign nuclear explosions in violation of nuclear test ban treaties.

The Naval Facilities Engineering Service Center, Port Hueneme, CA, and Sound & Sea Technology (SST), Ventura, CA, provided technical support for the project. This team had already successfully planned and installed several cable shore landings, including an HDD HDAS near-shore cable protection system at Ascension Island in the South Pacific Ocean (Sinclair, et.al. 2003a and 2003b). The HDD system model used in 2002 on Ascension Island again was employed on Wake Island.

Directional drilling work was by Island Mechanical Corp., Kapolei, HI. A 40,000-pound (178 kN) pullback Ditch Witch® JT4020AT HDD unit was employed to drill three pilot holes beneath the sea floor and exit beyond the surf zone at a water depth of about 55 feet (17 m). Navy divers attached three-inch (76mm) HDPE conduit to the drill string which was pulled through each pilot hole. This model drill unit was selected because: (1) its size permitted transportation by air to the remote site, (2) it can drill 1,000 feet (305 m) or more in coral and volcanic formations, and (3) its low mud flow requirements minimized the amount of fresh water needed for drilling operations. A mud motor would require significantly higher volumes of drilling fluids.

Selection of the location to launch the bores and paths of pilot bores was critical. Previous vertical borings on the island indicated primarily coral down to depths of over 325 feet (100 m). Samples of solidified coral and rock from the beach area tested 4,000 to 6,000 psi (28 to 41 MPa) unconfined compressive strength. "Experience with similar types of formations suggested that drilling operations would progress at approximately 175 feet (53 m) per day with minimal fluid returns," said Stan Black of SST.

The three bores were launched from the same entrance pit about 180 feet (55 m) from the shore line. Bore one was 883 feet (269 m), bore two 885 feet (270 m) and bore three 926 feet (282 m). A remote tracking antenna was used by divers to make locates every 30 feet (9 m) during offshore segments of the drilling operation. The antenna was placed directly on the sea floor, while the terrestrial receiver remained on the surface support boat. This minimized signal attenuation due to sea water conductivity.

Pilot holes of bores one and three took two days. Three days were required for bore two. A portion of that bore had to be re-drilled because of depth locating errors. Drilling operations began at a rate of about 215 feet (65 m) per day. Drilling rate was primarily determined by time required for underwater drill tracking. The process of locating the drill and sending the information back to the drillers took anywhere from 15 minutes to one hour per locate (Black 2008). As divers became more proficient, drilling rate increased dramatically. On the last full drilling day, the rate was 435 feet (133 m) per day.

Figure 5: Off Loading JT4020AT from C17 Cargo Plane at Wake Island

Fluid returns were minimal and only three of the 12 pallets of fluid additive transported to the site were used. Fresh water requirements were only 1,000 to 1,500 gallons (3780 to 5680 L) per day (Griffin 2006). (Photos are courtesy of Stan Black, SST.)

Figure 6: Tracking the Bore under the Seafloor

San Nicolas Island Offshore Waterline Replacement (Black 2008)

San Nicolas Island, located approximately 65 miles (105 km) off the coast of Southern California, is owned by the US Navy. A new 6-inch (152mm) diameter HDPE water line was needed between an existing onshore supply pipeline and the offshore water receipt terminal for periodic barge deliveries of potable water. The 1325-foot (404 m) bore extended under the shore to exit the seafloor at the offshore terminal.

Figure 7: Ditch Witch® JT4020AT Drill Unit at Work

Planning and execution of the waterline replacement was conducted by Sound and Sea Technology. The HDD drilling and conduit installation was accomplished using mobile drilling equipment and drillers from Sky View Construction, Post Falls, Idaho. Marine and diving support was provided by a detachment of US Navy divers. The Ditch Witch® JT4020AT drill unit was supported by a 1500 gallon (5680 L) mud reclaiming system to recycle drill fluid returned to the bore entrance. It was set up 270 feet (82 m) distance from the waterline. Steel matting was placed under the drill tracks for added support.

Knowledge of geology along the bore path is critical to success. San Nicolas Island is an uplifted geology with a layered structure (Figure 8). It consists of tilted stacked layers comprised of sandstone and siltstone. Rotary drilling is recommended in such conditions. An important factor in drill rig selection for a project on a remote island with limited potable water: Drilling fluid requirements are minimized when the drill bit is mechanically driven by the JT4020AT inner drill string.

Figure 8: Typical Geologic Layering on San Nicolas Island

The 6½ inch (165mm) diameter pilot bore was drilled at a rate of 225-275 feet (68-84 m) per day for first two-thirds of the bore and 125-150 feet (38-46 m) per day the last third. Of course divers were tracking the bore in deeper and deeper water as it progressed. Sections of HDPE pipe fusion welded together on the beach were towed to sea via a capstan winch on the diver vessel. Divers removed the drill head from the end of the drill string where it exited the seafloor, then attached the 14-inch (356 mm) diameter reamer and HDPE pipe for pullback through the bore. This project was conducted in the fall of 2007 (Black 2008). (Photos are courtesy of Stan Black, SST.)

Experiences in Pacific Northwest U.S. (Roberts 2008)

Numerous bores have been made with JT4020AT drilling units in various soil and rock conditions. For solid hard rock up to 25,000 psi (170 MPa), typical production rates are 175 to 200 ft (53 to 60 m) per 8 hrs of drilling. In 5,000 to 10,000 psi (35 to 70 MPa) sandstone, production increases to 300 ft (90 m) in 8 hrs. Cobble can typically be drilled at 200 to 250 ft (60 to 75 m) per 8 hrs. This time, of course, involves other aspects of the drilling process – such as tracking the progress of the directional downhole assembly.

A typical job for this drilling machine in Washington state is 500 ft (152 m). Bores of 1,000 ft (305 m) can be readily handled with a unit this size, and many have been done. Some holes as long as 1,400 ft (425 m) have been drilled. Bit speed is generally held between 225 and 250 rpm. The inner spindle drive system is typically held at a gage reading of 750 to 1000 psi (52 to 70 bar) by controlling the level of thrust applied to the bit via the outer drill string. While drilling the pilot bore in solid rock, drilling fluid flow may be held down to 10 to 15 gpm (38 to 57 Lpm) if the borehole is flushed at 40 gpm (150 Lpm) by pulling back each drilled joint of pipe and taking the bit back to bottom before adding the next one to the drill string. Fluid flow should gradually be increased with distance drilled. It is good practice to pull back three pipe joints every 100 to 150 ft (30 to 45 m) of drilling while flushing the hole. This can be quickly and easily accomplished because of an automated pipe loader on the JT4020AT. If nozzles are absent from the bit, drilling fluid pressure will be 100 to 200 psi (7 to 14 bar).

Experiences in Hawaii (Fair 2008)

The average bore length with a JT4020AT is 500 to 600 ft (152 to 183 m). The longest one was about 2,000ft (610 m), while 1200 to 1400 ft (365 to 425 m) bores are routine. A heavy drilling fluid mix is used when boring those distances to ensure the hole is cleaned. Point load tests on rock samples indicated a compressive strength of about 22,600 psi (156

MPa). It is softer at shallow depths and gets harder as drilling depth increases. In very hard rock, drilling rate may average only about 18 ft (5.5 m) per hour and some best days get only about 90 ft (27 m).

This contractor uses 3,000 to 4,000 gallons (11355 to 15140 L) of drilling fluid per day without recycling. Typical mud flow rate and pressure are 12 to 15 gpm (45 to 57 Lpm) and 250 to 500 psi (17 to 34 bar). Inner spindle rotation gage pressure is held at 500 to 800 psi (34 to 55 bar) while turning the bit at about 200 rpm.

Concluding Remarks

Rotary steerable HDD systems have been "field proven" to be suitable for drilling in mixed soil conditions and rock. Mud motor drilling systems have been successfully employed in near-surface directional drilling applications since the 1970s. Dual-member drill string driven rotary drilling systems have been successfully employed since the mid 1990s (Moore 2001; Tubb 2001). To those not intimately involved in small to mid-range HDD machine applications, they seem to be a well kept secret (Griffin 2006). The dual-member drill string rotary steerable JT4020AT system is a viable option for HDD near-surface applications up to 1000 ft (305 m) or more, and deserves a closer look by project planners and engineers.

Most downhole tools seem to have a narrow range of soils or formations where they are effective. Thus dealing with a wide range of rocky and hard soil conditions can require a multitude of tools or solutions to be successful. An exception is the dual-drill string All Terrain system. It has proven to be effective in a broad range of soil types.

"These … [All Terrain] machines can successfully drill certain conditions, including rock, at a lower per-foot cost than bigger machines with mud motor and fluid reclaimers," said contractor Byron Fair. He went on to say effectiveness is not limited to hard rock. They are productive in caliche, other softer formations, and in dirt (Griffin 2000). These comments were aimed at the Ditch Witch® JT2720AT, which was recently replaced by the JT3020AT.* In any case, his observations remain valid for the family of All Terrain models available today.

* The All Terrain system provides the opportunity for a 30,000 lb (133 kN) pull-back rated HDD machine to be very effective at drilling in difficult soil conditions. It was not chosen for comparison in this paper because there is not an effective mud motor or other technology near its size class that will compare in performance.

Acknowledgments

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Appendix A

Data and Calculations for an Example Mud Motor Drilling System

It is important to select the proper mud motor and supply it with an adequate flow of drilling fluid to turn the proper drill bit at a speed suited to the geological material being drilled. This involves five important steps: (Dorwart 2008)

1. Bit selection for the formation. One must assess the strength of the rock, length of hole, and product size to optimize bit cost. Rules of thumb: a TCI bit requires 4,500 to 5,000 pounds thrust per diameter-inch of cut (790 to 875 N/mm). A mill-tooth bit requires 2,500 to 3,000 pounds of thrust per diameter-inch (440 to 525 N/mm).
2. Hole size selection to have the best economics for the project. Diameter will be dependent on drill string capacity to resist buckling, required bit loading (contact pressure) to cut the rock, bearing capacity of the bit, and drill string capacity (ID) to transmit drilling fluid effectively to the motor.
3. Size downhole motor for sufficient torque output to supply rpm needed at the weight on bit (thrust) necessary to make the cut. Harder rock requires higher weight on bit. This increases torque required to turn the bit.
4. Size drilling fluid pump for selected motor to have a large range of power available for expected range of torque and rpm. Must be able to adjust weight on bit and rpm to find the “sweet spot” penetration rate for each type of formation expected along the borepath.
5. Size the mud cleaning system for full capacity of the drilling fluid pump so there is no delay in the recycling process.

Sufficient drilling fluid pressure must reach the motor for it to develop the torque necessary to turn the drill bit when in contact with the material being drilled. Hydraulic resistance of the flow path for drilling fluid increases with distance drilled, resulting in a reducing efficiency of the mud motor drilling system. The distance a particular motor set-up can effectively drill is limited by that reality. This is the focal point of the present analysis. Bit speed (rpm) and torque together determine the power output of a mud motor. Some motor manufacturers provide power curves in addition to peak or “rated” specifications. An example is shown below in Figure A-1.

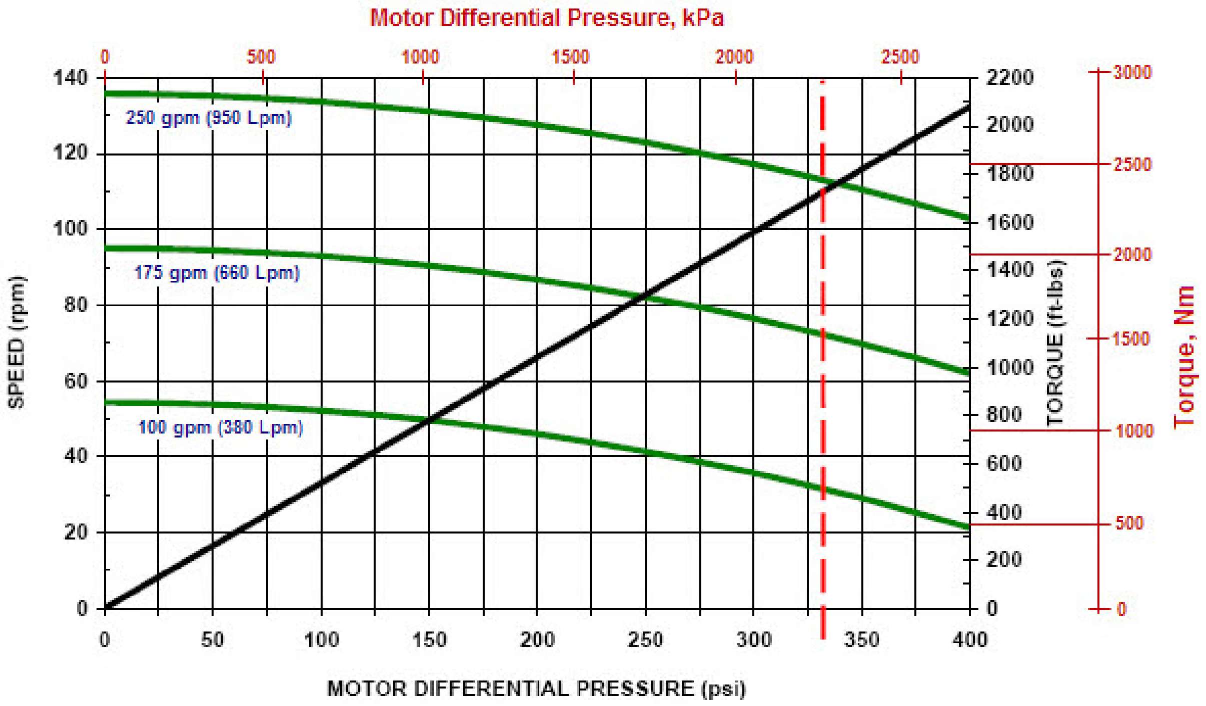

Figure A-1: Torque and Speed Curves for a 4¾-inch (121mm) Mud Motor[11]

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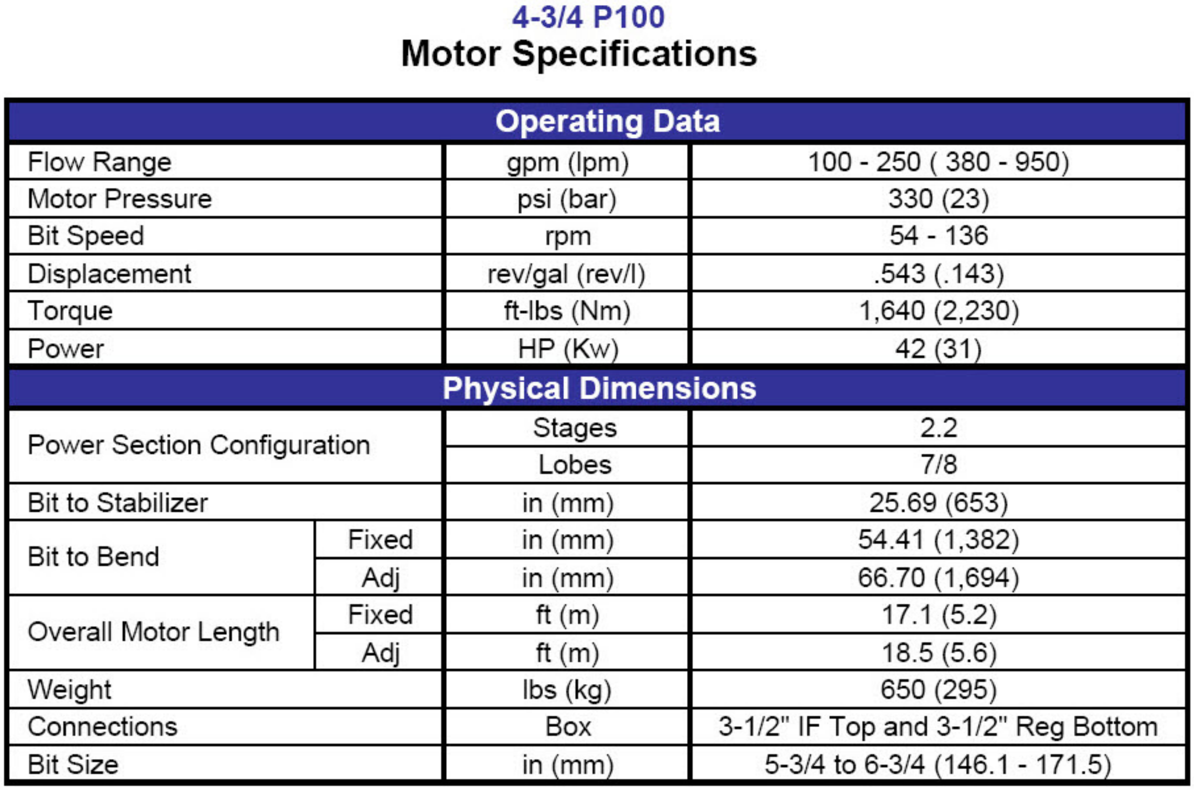
[11] P100 motor. Power curves and specifications available via the Internet at http://bicodrilling.com/ss_flexdrill.php

The dashed vertical red line indicates the “rated” operating torque at the point where it intersects the diagonally upwardly increasing black line. This is also near the point of motor stall that one should operate at least 100 psi (690 kPa) below according to (HDD Consortium 2008). However the motor manufacturer says enough safety factor is built into their “rated line” that they do not subtract additional pressure from it to get a recommended operating pressure (Cody and Doherty 2008). Thus the preferred differential pressure equals rated pressure minus off bottom pressure drop. The specifications for this motor are shown in Figure A-2.



4-3/4 P100

Motor Specifications

Operating Data			
Flow Range		gpm (lpm)	100 - 250 (380 - 950)
Motor Pressure		psi (bar)	330 (23)
Bit Speed		rpm	54 - 136
Displacement		rev/gal (rev/l)	.543 (.143)
Torque		ft-lbs (Nm)	1,640 (2,230)
Power		HP (Kw)	42 (31)
Physical Dimensions			
Power Section Configuration		Stages	2.2
		Lobes	7/8
Bit to Stabilizer		in (mm)	25.69 (653)
Bit to Bend	Fixed	in (mm)	54.41 (1,382)
	Adj	in (mm)	66.70 (1,694)
Overall Motor Length	Fixed	ft (m)	17.1 (5.2)
	Adj	ft (m)	18.5 (5.6)
Weight		lbs (kg)	650 (295)
Connections		Box	3-1/2" IF Top and 3-1/2" Reg Bottom
Bit Size		in (mm)	5-3/4 to 6-3/4 (146.1 - 171.5)

Figure A-2: Specifications for a 4¾-inch (121mm) Mud Motor

In this example, the motor will be powered by a Ditch Witch® JT8020 drill unit. The operating parameters of 196 gpm (740 Lpm)[12] and 1000 psi (69 bar) for the JT8020 mud pump seem to indicate ample capacity to power this motor. However, one must be aware of the various frictional flow losses that will limit the drilling range of a mud motor drilling system. These include various pressure losses between the mud pump and the downhole motor, “free-spinning” pressure drop across the motor, pressure drop across nozzles (jets) in the bit, and the pressure required to flow drill slurry (cuttings-entrained drilling fluid) up the borehole annulus to the entry pit. The latter loss increases with distance drilled, as does pressure drop in the drill string. At some distance into a pilot bore the power available to the motor will diminish to the point where productivity is adversely affected. For the P100 mud motor on a JT8020, the following information and example will show that this limit could be substantially less than 1000 ft (305 m).

We begin by looking into the two losses that increase with distance drilled: pressure drop in the drill string and borehole annular flow losses. Because of the limited amount of data available, this example assumes the drilling fluid has an approximate Marsh funnel viscosity of 50 seconds, and that the cuttings of geological material create a sand mixture with that drilling fluid. The properties of that slurry are taken from (Ariaratnam, et.al. 2003), and shown in Table 1.

Pressure losses were experimentally determined on the drill string of the JT8020 drill rig. Flow rates were increased in equal steps from 100 to 300 gpm (380 to 1135 Lpm). Graphical results are given below. The drilling fluid viscosity was a 50 second water-bentonite mix, with a specific gravity of 1.02 to 1.04. Figure A-3 indicates that the pressure drop per

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[12] The “spec sheet” output of this mud pump has been de-rated by an estimated volumetric efficiency of 85% when pumping drilling fluids rather than water (Coles 2008). Taking mechanical and hydraulic efficiencies of the pump drive system into account, the engine power needed to create this pressure and flow is 186 Hp (139 kW) – see Table B in main portion of this paper for details.

joint of drill pipe with 196 gpm (740 Lpm) of 50s drilling fluid flowing through it is about 7 psi (48 kPa). (Note: The fluids used in these tests may not be indicative of “typical” drilling fluids.)

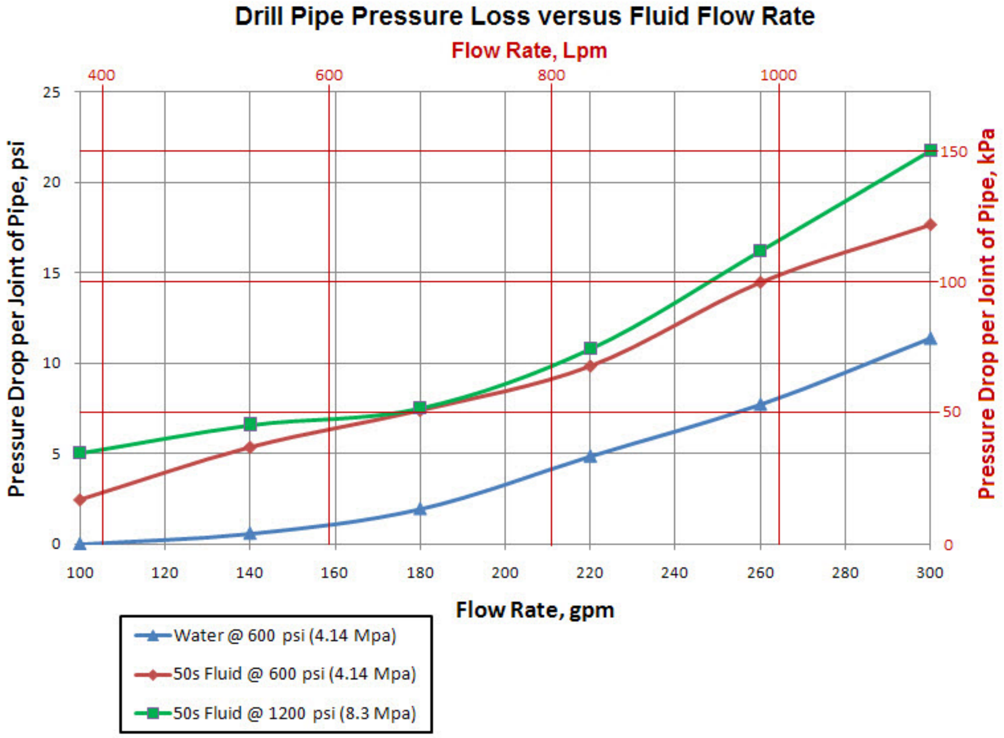

Figure A-3: Pressure Loss versus Flow Rate for One Joint of Drill Pipe 14.75 ft (4.5m) Long, with 4-inch (102mm) O.D. x 1½-inch (38 mm) I.D. Tool Joints and 3.62-inch (92 mm) O.D. Pipe

Calculation of annular flow losses have been modeled by several researchers and reported in the literature (Ariaratnam, et.al. 2003; Ariaratnam, et.al. 2007; HDD Consortium 2008; and others). Ariaratnam, et.al. 2003 tested the rheological properties[13] of two drilling fluids and various concentrations of three soil types mixed into those fluids. They utilized these data in the Bingham Plastic Model to calculate annular flow loss as a function of fluid mixture density and bore length. The equations involved are (Ariaratnam, et.al. 2003):

The average velocity of drilling fluid in the borehole annulus (V_a) is:

$$V_a \text{ (ft/sec)} = (0.408 \text{ x } PO_{GPM}) / (ID^2_{HOLE} - OD^2_{DP}) \qquad (1)$$

where PO_{GPM} = pump output in gal/min; ID_{HOLE} = diameter of hole or inside diameter of casing in inches; and OD_{DP} = outside diameter of the drill pipe or drill collar in inches.

For a laminar flow condition, the pressure drop (PD_a) in the annulus is then:

$$PD_a = \{[(PV \text{ x } V_a)/1000(ID_{HOLE} - OD_{DP})^2] + [YP/200(ID_{HOLE} - OD_{DP})]\} \text{ x } L \qquad (2)$$

where PV = plastic viscosity in cP; YP = yield point in lb/100 ft^2; and L = length in ft.

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[13] “Rheology is defined as the science and study of the deformation and flow of matter, including its elasticity, plasticity, and viscosity. The term is also used to describe the properties of a given fluid. Drilling fluid rheology thus refers to the rheological properties of a given drilling fluid mixture.” (Baumert, et.al. 2005)

Metric versions of these equations are given in (Ariaratnam, et.al. 2007). These equations were applied to data for the JT8020, a borehole ID of 6½ inches (165mm), and rheological properties in the following table from (Ariaratnam, et.al. 2003) to get the family of lines shown in Figure A-4.

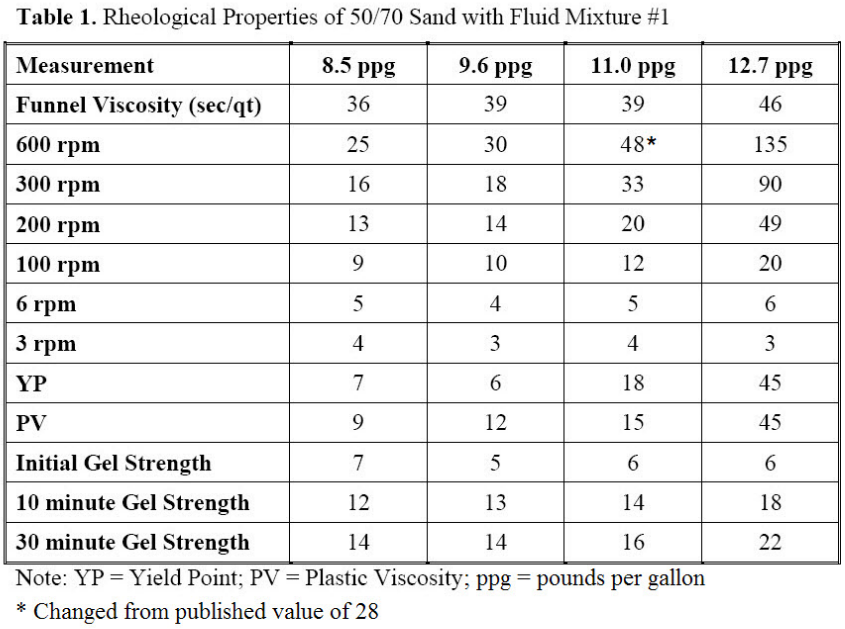

Table 1. Rheological Properties of 50/70 Sand with Fluid Mixture #1

Measurement	**8.5 ppg**	**9.6 ppg**	**11.0 ppg**	**12.7 ppg**
Funnel Viscosity (sec/qt)	36	39	39	46
600 rpm	25	30	48*	135
300 rpm	16	18	33	90
200 rpm	13	14	20	49
100 rpm	9	10	12	20
6 rpm	5	4	5	6
3 rpm	4	3	4	3
YP	7	6	18	45
PV	9	12	15	45
Initial Gel Strength	7	5	6	6
10 minute Gel Strength	12	13	14	18
30 minute Gel Strength	14	14	16	22

Note: YP = Yield Point; PV = Plastic Viscosity; ppg = pounds per gallon

* Changed from published value of 28

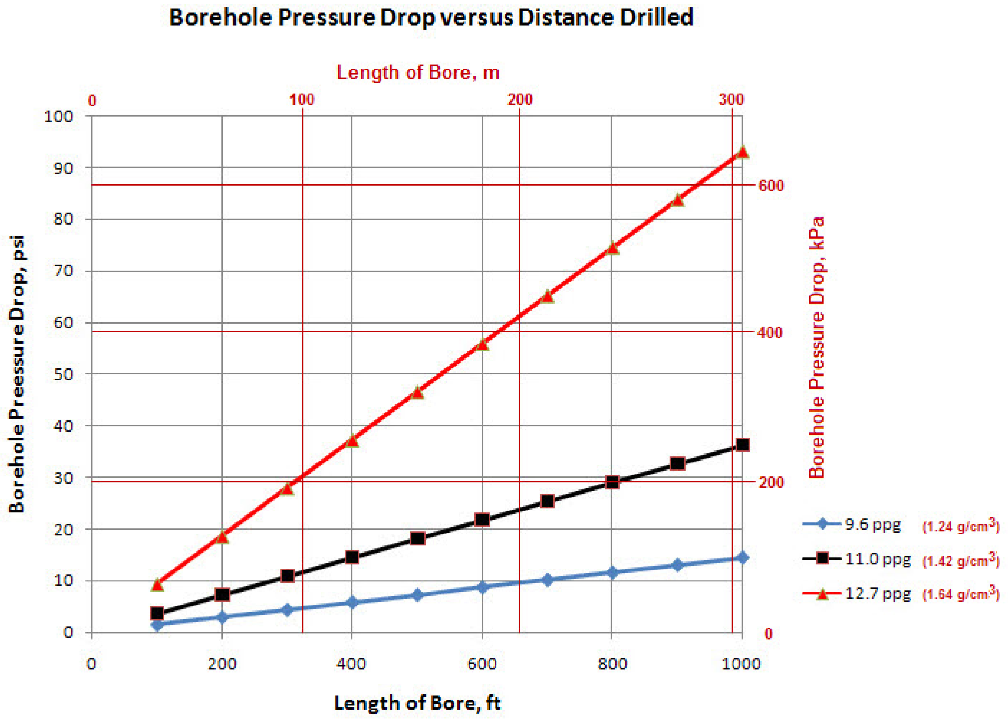

Figure A-4: Annular Flow Loss versus Distance Drilled at Different Concentrations of Slurried Cuttings

The data line for 8.5 ppg (1.10 g/cm^3) is not given in Figure A-4 because it essentially underlies the line for 9.6 ppg (1.24 g/cm^3). Those two concentrations are not far from the density of virgin drilling fluid. Thus the middle (black) line was chosen for the present example. At 500 ft (152 m) of drilled borehole, the annular pressure at the bottom of the hole caused by resistance to annular flow is about 18 psi (124 kPa) and double that at double the distance.

The pressure in the borehole is the sum of the dynamic pressure required to maintain return flow (move cuttings entrained fluid out of the borehole) and the static hydraulic pressure head back to the entry pit (Dorwart 2008). A minimum pressure head is needed in borehole to prevent collapse; i.e., if there is a membrane effect from the filter cake, the hole should remain stable with a positive internal pressure. The latter value should be 1.5 to 4 psi (10 to 30 kPa) above the in situ ground water level (Baumert 2005). This variable is being ignored in the present example. However, elevation head of the drill slurry must be taken into account for deeper bore paths. We will assume a 20 foot depth (6.1 m), even though depth will vary with progress along the borepath. For 11 ppg (1.42 g/cm^3) drill slurry, the static head would be about 11.5 psi (80 kPa) at the assumed depth.

These pressures represent back pressure on the mud motor, and also exert pressure on the formation being drilled. If that pressure is higher than the confining pressure of overburden, drilling fluid will be lost through the wall of the borehole. There are three fluid loss mechanisms: (1) leakage into the surrounding formation, (2) jacking of the overburden or nearby features – such as the upheaval of a road surface, and (3) fracturing or hydrofracture. Ease of occurrence is in that order (Dorwart 2008). The appearance of "inadvertent returns" at the ground surface or in a body of water is commonly referred to as a "frac-out". This potential is a major concern when drilling with the high pressure and flow rates needed to power a mud motor, as the drill slurry must return to the surface through a relatively small annulus (Baumert 2005).

The various pressure losses in the drilling system and borehole are tabulated below for drilled distances of 500 ft (152 m) and 1000 ft (305 m).

Table 2: Pressure Losses in a Mud Motor Drilling System

	500 ft (152m) Borehole		1000 ft (305 m) Borehole	
Parameter	English	Metric	English	Metric
Pressure Drop through Spindle & Fittings	100 psi	690 kPa	100 psi	690 kPa
Number of Joints of Drill Pipe[14]	34	34	68	68
Pressure Drop in Drill String	238 psi	1640 kPa	476 psi	3280 kPa
Borehole Annular Pressure Loss	18 psi	124 kPa	36 psi	248 kPa
Static Pressure Head at 20 ft (6.1 m) Bore Depth	11.5 psi	80 kPa	11.5 psi	80 kPa
Pressure Drop in Bit Nozzles	165 psi	1140 kPa	165 psi	1140 kPa
Off Bottom Pressure Drop of Mud Motor[15]	100 psi	690 kPa	100 psi	690 kPa
Max Pressure Available to Mud Motor	368 psi	2535 kPa	112 psi	770 kPa

The maximum pressures available to the mud motor on the bottom line of Table 2 can be taken to Figure A-1 as input to the motor performance curves. One must also input the output flow of the JT8020 mud pump. How this is done is shown in Figure A-5. The available pressure at 500 ft (152 m) is 368 psi (2535 kPa), but this is higher than the allowable input pressure of 100 psi (690 kPa) below the dashed vertical red line in Figures A-1 and A-5. Therefore the entry point is indicated in Figure A-5 by a black dashed vertical line positioned at 230 psi (1585 kPa). Its intersection with the black diagonal line is transferred to the right hand scale to obtain an output torque of 1200 lb-ft (1625 Nm). Extending the vertical dashed line (now green in color) to a point estimated to be on a speed curve (not shown) for 196 gpm (740 Lpm) of flow and transferring that point to the left hand scale yields an estimate of 95 rpm out of the motor. The power output of the mud motor calculated from these torque and speed values is shown in Table 3.

Because the maximum recommended input pressure to the motor is less than that available, the operator would have to limit thrust on the drill string to the point of achieving a reading of about 860 psi (59 bar) on the drill rig mud pump

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[14] To determine the number of joints of drill pipe in the drill string at each distance, one must account for the length of the drill bit, downhole motor and length of drill pipe above the surface entry point. Because flow losses through the non-magnetic drill collar for the tracking electronics are not known, it is counted as one joint of drill pipe.

[15] Estimated by the mud motor manufacturer (Cody and Doherty 2008).

pressure gage.[16] The gage reading would have to be even less when drilling the earlier portion of the bore. At the very beginning of the bore the mud pump gage pressure should be held under about 600 psi (40 bar) because flow losses in the borehole and drill string are nearly zero. Conversely as the bore progress beyond 500 ft (152 m), the gage reading will eventually register the maximum pressure rating of the mud pump with the same amount of thrust on the mud motor as before. From that point forward, drilling performance will decline. In this example, the point of this onset is 770 ft (235 m) into the bore.[17] Continuation beyond that distance will soon reach a point where there may not be enough pressure available at the motor to overcome its starting resistance – which is somewhat above its tabulated "free-spinning" off bottom pressure drop and is drilling fluid viscosity dependent (Cody and Doherty 2008).

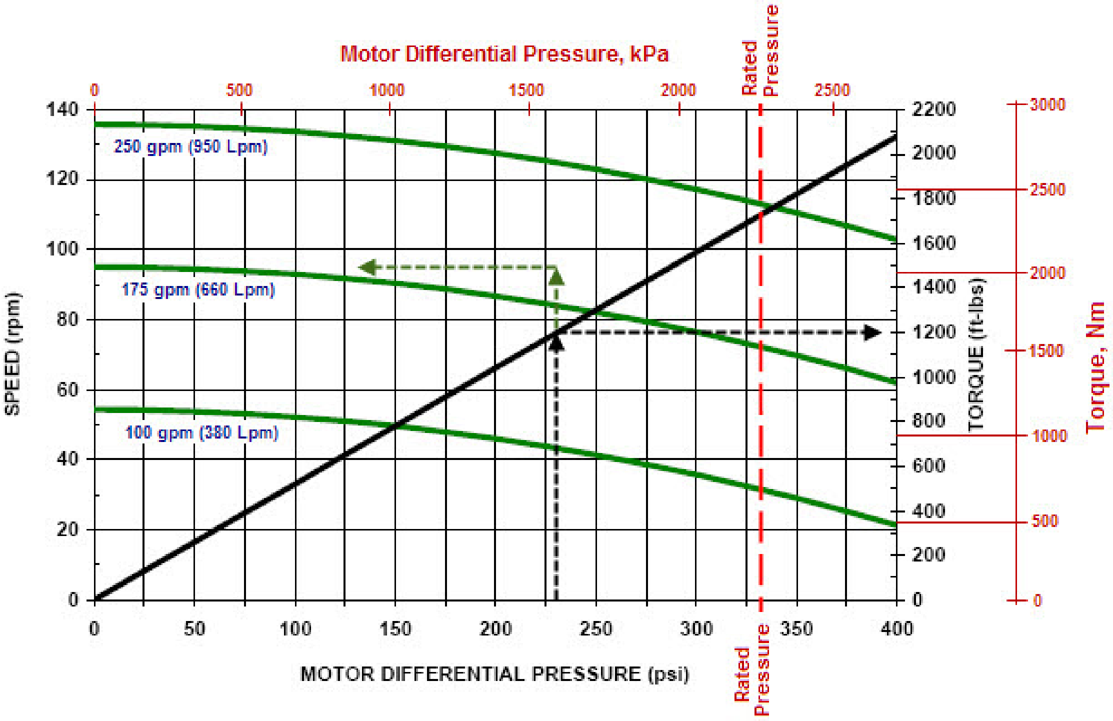

Figure A-5: Determination of Mud Motor Output Power for a Given Input Pressure and Flow

Table 3: Mud Motor Output Power and Drilling System Efficiency
500 ft (152 m) into a Pilot Bore

Parameter	English	Metric
Motor Output Torque	1200 lb-ft	1625 Nm
Motor Output Speed	95 rpm	95 rpm
Motor Output Power	21.7 Hp	16.2 kW
Mud Pump Input Power	160 Hp[18]	120 kW
Drilling System Efficiency	13.5%	13.5%

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[16] Operating pressure should generally not exceed 230 psi at the motor. The difference between this and the maximum pressure available at the motor should be subtracted from the maximum pressure output of the mud pump. [1000 psi – (368 psi -230 psi)] = 860 psi = the recommended mud pump gage reading at the end of a 500 ft (152 m) borehole.

[17] This can be determined by calculating the rates of increase in borehole annular pressure loss and drill pipe pressure drop per unit measure of advancing bore and summing them. This yields 0.51 psi/ft. The excess pressure available to the mud motor at 500 ft is 368 – 230 = 138 psi. Dividing this by 0.51 psi/ft yields 270 ft beyond the 500 ft point. Sum the distances to get 770 ft (235 m).

[18] The mud pump input power in this instance is based upon the drilling fluid pressure the mud motor can accept and all the losses down to the 500-foot-away mud motor. Earlier it was pointed out that the drill rig mud pump pressure gage reading would be 860 psi at this point. Thus the mud pump input power would be (860/1000) x (the 186 Hp max value) = 160 Hp.

This analysis shows that a lot of energy is expended by the top side engine to obtain approximately 22 HP (16 kW) at the drill bit. That is the inherent nature of a mud motor drilling system. The development of low-flow mud motors has allowed them to be applied on smaller HDD machines (Griffin 2001; Griffin 2002b). However, one must consult with the motor manufacturer to insure that satisfactory performance will result.

The power available at the drill bit could be increased by utilizing a higher quality mud motor. For instance, a 4¾ inch (120 mm) SS100SR motor from this manufacturer could handle all the available pressure at 500 ft (152 m) shown in Table 2. This motor would have a torque output of about 1800 lb-ft (2440 Nm) and speed of 95 rpm, yielding an output power of 32.6 Hp (24.3 kW). In this case, the input power would be 186 Hp (139 kW) for system efficiency of 17.5%. Of course the rental fee or purchase price would be higher for this motor. This should be weighed against the anticipated increase in borehole production rate.

One should be aware that many mud pump and mud motor ratings and performance curves are based upon water as the fluid. The above estimates of system efficiency will be lower for a typical drilling fluid mixture. This was taken into account for the mud pump by applying an 85% volumetric efficiency factor. Such a de-rating factor for the mud motor was not found. This makes it even more important to involve the motor manufacturer or supplier in the process of setting up a productive mud motor drilling system.
