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Advanced Geothermal Foam Drilling Systems (AFS)

Phase I Final Report – Part I

W. C. Maurer

July 1999

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Work Performed Under Contract No. DE-FG07-98ID13681

**For
U.S. Department of Energy
Assistant Secretary for
Energy Efficiency and Renewable Energy
Washington, DC**

**By
Maurer Engineering Inc.
Houston, TX**

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Contract No. DE-FG07-98ID13681

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Table of Contents

	Page
Executive Summary	v
Conclusions and Recommendations	vii
1. Background	1-1
2. MUDLITE Hydraulics Model	2-1
3. Description of Advanced Foam Drilling Systems (AFS)	3-1
4. Phase I AFS Evaluation Studies	4-1
5. References	5-1

APPENDICES

- Appendix A. Motor Efficiency and Performance Equations
- Appendix B. Drilling Rate and Specific Energy Equations
- Appendix C. Effect of Differential Fluid Pressure on Drilling Rate
- Appendix D. MUDLITE Foam Hydraulic Calculations

Executive Summary

An Advanced Foam Drilling System (AFS) has been investigated that utilizes two concentric coiled tubing (CT) strings to transfer water and air to the hole bottom where they are mixed to produce foam (Figure 1).

Figure 1. Advanced Foam Drilling System

With conventional foam systems, air and water are mixed together at the surface and foam is pumped to the hole bottom to power the motor and clean the hole.

The AFS (bottomhole gas injection) has several advantages over conventional foam systems including it significantly reduces compressor requirements in shallow wells as shown in Figure 2. Compressors constitute a major cost on many underbalanced wells, so reducing compressor requirements can significantly reduce the cost of drilling these wells.

Figure 2. Air Compressor Requirements

Another advantage of the AFS is that the downhole motor can deliver up to twice as much power and drill twice as fast as motors on conventional foam systems since the motors are powered by water instead of by a compressible foam (Figure 3).

Figure 3. Drilling Rate Comparison

A cost analysis showed that the cost for drilling a 3,000-ft well, excluding completion costs, was \$44,300 with the AFS compared to \$86,400 for a conventional foam system (Figure 4). Most of this cost reduction was due to the higher drilling rate of the AFS. This shows that the AFS has potential for significantly reducing underbalanced drilling costs.

Figure 4. Foam Drilling Costs

The AFS also allows the use of conventional mud pulse MWD tools since the pulses are transmitted up the water flow line instead of through the compressible foam. These technical and cost advantages should allow the AFS to greatly expand the use of foam drilling in geothermal fields where lost circulation is a problem.

Laboratory and field tests are needed to demonstrate the effectiveness of this advanced foam drilling system and to accelerate its implementation in the field.

Conclusions and Recommendations

The following conclusions were reached as a result of this Phase I study:

1. The Advanced Foam System (AFS) has the potential to significantly reduce geothermal drilling costs.
2. The AFS can reduce compressor pressure by 50 percent in a 3,000-ft well, thereby significantly reducing compressor costs.
3. The AFS can increase drilling rates by 100 percent in a 3,000-ft well due to higher drilling motor power output.
4. The AFS allows good control of bottom-hole pressure to overcome lost circulation problems.
5. AFS generates foam at the hole bottom to effectively clean the hole.
6. The "foam quality" can be accurately maintained throughout the well for effective borehole stability control.
7. Hole making drilling costs can be reduced up to 50 percent and overall well costs reduced by 25 percent using this advanced foam system.
8. Phase II laboratory and field tests are needed to verify the effectiveness of the AFS.
9. The AFS will be commercialized following the Phase II field tests.

1. Background

Oil companies first began drilling wells with air in the late 1940s. Primary motivations to use air were to increase drilling penetration rates through hard formations and to overcome severe lost-circulation problems. Increased drilling rate as a result of reduced differential pressure at the hole bottom (Figure 1-1) was the most important benefit of underbalanced drilling enjoyed by these operators.

The beneficial effects of reduced hydrostatic pressure with regard to increased drilling rates occur at all bit weights, as illustrated in Figure 1-2. Other benefits of air drilling include reduced formation damage, reduced lost circulation, and fewer problems with differential sticking.

Many tight gas reservoirs in the United States are attractive targets for underbalanced drilling because they are located in hard-rock country where tight (low-permeability) formations are more susceptible to formation damage from invasion of conventional drilling fluids.

Fluids lighter than water (i.e., specific gravity $SG < 1$) are also required when drilling underbalanced in underpressured or depleted reservoirs. Many types of fluids systems are used, ranging from 100% air to 100% liquid. All fluids with densities below 6.9 ppg ($SG = 0.83$) used to date contain gas or air in some form (Figure 1-3).

During the 1950s and 1960s, the variety of drilling fluids was expanded to include mist, foam, and aerated fluids. Each of the two-phase systems shown in Figure 1-4 has been used successfully for drilling during the past four decades. However, the introduction of these two-phase fluids was accompanied by significantly increased difficulty in predicting fluid flow parameters with these compressible fluids.

The hydraulics for 100 percent liquid is relatively easy to predict because liquid can normally be assumed as essentially incompressible. One-hundred percent gas is harder to model, even though it is still one continuous phase, due to its compressibility. The hydraulics of mist and foam is the most difficult to model since these fluids are both compressible and two-phase. Foam is generally defined as any two-phase fluid with liquid as the continuous phase (having a gas emulsified in it), while mist is defined as a two-phase fluid having gas as the continuous phase (Figure 1-5). Gas becomes the continuous phase at gas fractions above 97-98 percent by volume.

The advantages of various lightweight fluids are summarized in Table 1-1. The major advantage of using underbalanced fluids is increased drilling rates.

TABLE 1-1. Advantages of Lightweight Drilling Fluids

AIR/GAS/MIST	FOAM
HIGH DRILLING RATES	HIGH DRILLING RATES
LOW CHEMICAL COSTS	HANDLES HIGH WATER INFLUXES
EASY TO USE	IMPROVED HOLE STABILITY
REDUCED ENVIRONMENTAL IMPACT	EXCELLENT HOLE CLEANING
	REDUCED COMPRESSORS
	NO DOWNHOLE FIRES

Fluids having gas or air as the continuous phase have the advantage of simplicity, low costs for additives, and minimal equipment requirements. These fluids also lead to less environmental risk since there is minimal liquid waste disposal. Table 1-2 shows the disadvantages of underbalanced drilling fluids.

TABLE 1-2. Disadvantages of Underbalanced Fluids

AIR/GAS/MIST	FOAM
CANNOT HANDLE HIGH WATER INFLUXES	COST OF ADDITIVES
HOLE EROSION	COMPLEX HYDRAULICS CALCULATIONS
DOWNHOLE FIRES	
HOLE INSTABILITY	

The primary disadvantage of air, gas or mist systems is their inability to handle formation fluid influxes. In practice, when an influx becomes too great for air or mist to handle, the fluid system must usually be switched to foam, aerated fluid, or 100% liquid.

Foams eliminate many of the problems associated with air, gas, and mist drilling fluids including borehole stability problems, high compressor requirements, and downhole fires and explosions. The greatest advantage of foams is their ability to safely handle large influxes of oil or water from the formation.

Foam has the additional advantage of increased cuttings-carrying capacity. Figure 1-6 shows that, as the foam quality increases (i.e., the percent air increases), the lifting force decreases. The maximum lifting force is achieved with 2 to 5% liquid, just within the region defined as a foam. As the water content

Fig. 1-1. Differential Pressure and Drilling Rate (Moffitt, 1991)

Fig. 1-2. Drilling Rate vs. Differential Pressure

Fig. 1-3. Fluid Density

Fig. 1-4. Flow Regimes (Lorenz, 1980)

Fig. 1-5. Fluid Phase Continuity

Fig. 1-6. Foam Lifting Capacity (Beyer et al., 1972)

of the foam increases, its viscosity decreases along with its ability to carry cuttings. As the fluid crosses over into a gas-continuous phase, it continues to effectively lift cuttings, but its ability to hold cuttings in suspension disappears at low velocities.

With a conventional foam system, air or nitrogen is mixed with the liquid phase at the surface, or injected at some point in the drill-string casing annulus through a "parasite" string strapped to the outside of the casing (Figure 1-7). The Advanced Foam Drilling System (AFS) being developed on this project utilizes a concentric coiled tubing (CT) string to inject the air at the hole bottom to reduce compressor pressure, increase drilling rates and reduce drilling costs. The injected air reduces pump pressure at the surface and lowers the hydrostatic head in the annulus.

Figure 1-7. Parasite Injection String

Figure 1-8. Volume Requirement Chart (Poettman and Begman, 1955)

Downhole fires and explosions are a problem when drilling with air, especially in long horizontal wells where days or weeks are spent drilling in oil or gas pay zones. If a flammable mixture of oxygen and natural gas or oil exists downhole, ignition can occur due to heat generated by friction or by sparks generated by the drill bit.

Although foam or aerated muds eliminate the potential for fires and explosions, their use is hindered by the increasingly complex hydraulics calculations and the high cost of foam chemicals. Prior to the availability of computers, nomographs and charts (Figure 1-8) were used to estimate circulating pressures. Maurer Engineering has developed a hydraulics computer model MUDLITE that accurately predicts foam drilling hydraulics to allow engineers to better plan and drill wells. This model, described in the next section, was used to make the example hydraulics calculations used in this Phase I study.

2. MUDLITE Hydraulics Model

Maurer Engineering has developed an air/mist/foam hydraulics model MUDLITE that accurately predicts ECDs in geothermal wells to overcome lost circulation and other problems shown in Figure 2-1.

Many types of fluid are used to drill geothermal wells, ranging from 100% gas to 100% liquid including air, mist, foam, water or mud as shown in Figures 2-2 and 2-3. Some of these fluids, including air and mist, can result in poor hole cleaning, high torque and drag, and stuck drill pipe. Figure 2-4 shows that multiple hydraulics models are required to accurately describe the rheology of these different geothermal drilling fluids.

Maurer Engineering's MUDLITE lightweight fluid hydraulics model accurately predicts air, mist and foam drilling in oil and gas wells, but does not take into account the effect of wellbore circulating temperatures on the drilling fluids.

Maurer Engineering's GTEMP wellbore thermal model accurately predicts circulating temperatures in geothermal wells. Figure 2-5 shows a GTEMP calculation for a geothermal well where the bottom-hole temperature decreases from 600°F to 454°F after circulating for 12 hours (0.5 day) and to 387°F after circulating for 20 days. These temperature changes have major effects on fluid rheology and ECDs, and must be taken into account when calculating ECDs in geothermal wells.

The DOE is currently funding Maurer Engineering to develop a multiphase flow geothermal model GEODRIL that takes into account the effect of circulation temperature on hydraulics, pressures, ECDs, hole cleaning, and other drilling parameters.

Once a foam drilling operation is underway, only a few variables can be adjusted including: 1) gas injection rate, 2) liquid injection rate, 3) choke pressure on the annulus, 4) fluid viscosity and, 5) ROP. MUDLITE takes all of these variables into account.

MUDLITE will handle air or nitrogen injection at various points in the well (Figure 2-6), including injecting gas 1) down conventional drill pipe, 2) through "parasite" strings, 3) through a temporary concentric casing string that is removed when the well is completed, and 4) through dual wall drill pipe or concentric coiled tubing.

MUDLITE was used in this study to compare the hydraulics for conventional foam drilling and the Advanced Geothermal Foam Drilling System (AFS).

Fig. 2-1. Geothermal Drilling Problems

Fig. 2-2. Geothermal Drilling Fluids

Fig. 2-3. Geothermal Drilling Fluids

Fig. 2-4. Geothermal Fluid Models

Fig. 2-5. GTEMP1 Thermal Model

Fig. 2-6. Down Hole Air Injection

3. Description of Advanced Foam Drilling System (AFS)

The Advanced Geothermal Foam Drilling System (AFS) being developed on this project uses a concentric coiled-tubing (CT) string to power a downhole motor and generate foams downhole (Figure 3-1).

Water containing foaming agents, corrosion inhibitors, borehole stabilizers, and other chemicals will be pumped down the inner string of the concentric pipe (1,500 to 2,000 psi) to the hole bottom to power a downhole drilling motor. Air or nitrogen will be pumped down the annulus between the two concentric strings (600 to 1,000 psi) to the hole bottom and mixed with the water to form a stiff foam similar to shaving cream (Figure 3-2). The foam will then flow up the wellbore annulus, effectively lifting the cuttings and water inflows to the surface.

Maurer Engineering is developing a high-pressure CT drilling system for the Federal Energy Technology Center (FETC) in Morgantown, WV, that utilizes concentric tubing to deliver high-pressure fluid to a jet bit (10,000 psi) and low-pressure fluid (1,000 to 2,000 psi) to a PDM motor. This project includes BJ Services, Quality Tubing and Stewart & Stevenson as industry partners that will commercialize this system. Spinoffs from this FETC project will accelerate development of the AFS since many of the tools such as concentric drillpipe, downhole motors, and drill bits are similar.

The AFS motor, powered by water pumped down the inner CT, will deliver much more power and drill at much higher rates than motors used with conventional foam drilling systems. The foam provides accurate bottom-hole pressure (ECD) control to prevent fluid influxes, lost circulation, and borehole stability problems while providing excellent hole cleaning. The AFS can be used to drill 1,000- to 2,000-foot horizontal wells to intersect natural fractures and increase geothermal well productivity 3- to 5-fold.

Foam has excellent cuttings lifting ability as shown by the 2-inch pieces of rock setting on top of a stiff foam with negligible settling into the foam (Figure 3-3). As a result, foams require annular velocities of only 40 to 60 ft/min to effectively clean the holes compared to 3,000 ft/min with air or mist drilling. This good lifting ability significantly reduces hole problems and compressor costs.

A choke will be used at the surface with the AFS to accurately control ECDs and maintain stable foams at the top of the well to ensure good hole cleaning. Bottom-hole borehole pressures will be accurately controlled by varying the rheological properties of the foam and the size of the choke orifice.

Downhole positive-displacement motors (PDMs) powered by water pumped down the inner tube, will provide high drilling rates. PDM motors will be used in the upper cool sections of wells. Later, the NADET Advanced Geothermal Turbodrill (Figures 3-4 and 3-5) will be used in the lower hot sections of wells where thermal degradation of rubber stators cause rapid failure of PDM motors.

The downhole motors can be powered by water, thus allowing high torque, high power output, high ROP, and good cooling. Tests recently conducted by Maurer Engineering for LANL showed that PDMs operating on water deliver up to 5 to 6 times more power than PDMs operated on mist or foam (Figure 3-6). Therefore the ability to operate motors on water with this AFS is a major advantage of this system.

Injecting air or nitrogen at the hole bottom reduces the compressor pressure by up to 1,000 psi, significantly reducing compressor costs.

The AFS combines the benefits of both foam and downhole motor drilling to significantly reduce geothermal drilling costs.

The concentric drillstring will consist of two concentric strings of coiled tubing (CT) or dual-wall drillpipe. CT up to 3½-inch diameter is currently used for drilling applications and could be used with 12¼-inch geothermal wells due to the excellent cuttings lifting capacity of foams.

Advantages of the AFS include:

1. Compressor costs reduced 50 to 70 percent
2. Excellent cuttings lifting capacity
3. Motor power output increased 2- to 3-fold
4. Good bottom-hole pressure control
5. Improved borehole stability
6. Good water lifting capability
7. High-temperature capability
8. Good MWD and motor cooling

This advanced foam drilling system has potential for significantly reducing geothermal drilling costs and accelerating the use of horizontal drilling to increase the productivity of geothermal wells 3- to 5-fold.

Fig. 3-1. Advanced Geothermal Foam Drilling System (AFS)

Fig. 3-2. Stiff Drilling Foam

Fig. 3-3. 2" Rock Fragments on stiff foam

Fig. 3-4. Advanced Geothermal Turbodrill (AGT)

Fig. 3-5. Planetary Speed Reducer

Fig. 3-6. Effect of Drilling Fluids on PDM Performance

4. Phase I AFS Evaluation Studies

The Phase I Advanced Foam System (AFS) evaluations show that the AFS has many advantages over conventional foam drills including lower compressor pressure, higher drilling rates and reduced drilling costs as shown below.

EXAMPLE WELL

Conventional and advanced foam drilling were compared for the 3,000-ft deep example wells described in Table 4-1.

TABLE 4-1. Example Well Conditions

	Conventional Foam System	Advanced Foam System
Well Type	Vertical	Vertical
Well Depth (ft)	3,000	3,000
Bit Diameter (inches)	3.75	3.75
Outer CT (inches)	2.000 x 1.732	2.375 x 2.063
Inner CT (inches)	—	1.500 x 1.232
Choke Pressure (psi)	50	50
Motor Displacement (gal/rev)	0.125	0.125
Motor Mechanical Efficiency	0.79	0.79
Motor Hydraulic Efficiency	0.88	0.88
Rock Specific Energy (psi)	100,000	100,000

Unless stated otherwise, the examples shown are for an air flow rate of 120 scfm and a water flow rate of 70 gpm.

The Conventional Foam System (CFS) utilizes a *single* 2-inch coiled tubing (CT) string whereas the Advanced Foam System (AFS) utilizes a *concentric* CT string (2 $\frac{3}{8}$ -inch and 1 $\frac{1}{2}$ -inch) where the air or nitrogen is pumped to the hole bottom in the annulus between these two CT strings and water is pumped to the hole bottom in the inner CT string to power the motor. The water and air are mixed together at the hole bottom to form foam.

COMPRESSOR PRESSURE

One of the major advantages of the AFS over conventional foam systems is lower compressor pressures in many cases. Figure 4-1 shows that the compressor pressure is independent of motor pressure for the AFS, whereas with conventional foam drilling (surface injection), the compressor pressure increases with increased motor pressure.

For example, with 2,000 psi across a PDM motor in a 3,000-ft well, the AFS requires a compressor pressure of 1,110 psi compared to 2,050 for a conventional foam system. The lower pressure significantly reduces compressor costs with the AFS.

The compressor pressure increases with increased water flow rates (30 to 70 gpm) and decreases with increased air flow rate (60 and 120 scfm) due to fluid density changes in the wellbore annulus (Figure 4-2).

Figure 4-3 shows that in a 6,000-ft well, the compressor pressures are nearly equal, showing that the benefits of lower compressor pressure with the AFS decreases with increased well depth.

DRILLING RATE

A major advantage of the AFS is that drilling rates would be much higher with the AFS than with conventional foam drilling because motors on the AFS system can operate at much higher pressures and higher power levels than with conventional foam systems.

Figure 4-4 shows that an AFS motor (2,000 psi) will drill at 102 ft/hr with 70 gpm water circulation, compared to 51 ft/hr for a conventional system motor (1,000 psi) due to higher motor power (57 vs. 28 hp) (Figure 4-5). With equal pressure on the motors, drilling rates are essentially equal with both systems, and independent of well depth (Figure 4-6 and 4-7). The slight difference in drilling rate is due to significantly higher flow rate through the motor with surface gas injection since both the air and water flow through the motor in this case.

MOTOR POWER

The AFS motor power, P , increases with increased motor pressure drop and increased flow rate as follows (Appendix A):

$$P = \frac{\eta p Q}{1,714} \quad (4-1)$$

and the drilling rate, R , varies as (Appendix B):

$$R = \frac{2.521 \times 10^6 P}{D^2 E} \quad (4-2)$$

Fig. 4-1. Compressor Pressure

Fig. 4-2. Compressor Pressure

Fig. 4-3. Compressor Pressure

Fig. 4-4. Drilling Rate

Fig. 4-5. Motor Power

Fig. 4-6. Drilling Rate

where

- P = Motor Power (hp)
- R = Drilling Rate (ft/hr)
- p = Motor Pressure Drop (psi)
- D = Hole Diameter (in)
- E = Rock Specific Energy (psi)
- Q = Flow Rate (gpm)
- η = Motor Overall Efficiency (≈ 0.695)

Example Case:

- Q = 120 gpm
- p = 2,000 psi
- E = 100,000 psi
- D = 3.75 inches

the power output equals (Eq. 4-1):

$$P = \frac{0.695 \times 70 \times 2,000}{1,714} = 56.8 \text{ hp}$$

and the drilling rate equals (Eq. 4-2):

$$R = \frac{2.521 \times 10^6 \times 57}{(3.75)^2 \times 100,000} = 102 \text{ ft/hr}$$

EQUIVALENT CIRCULATING DENSITY

Wellbore annular pressures are usually expressed as "equivalent circulating densities" (ECDs) which include both fluid densities and annular pressure drops. ECDs are useful since when the ECD equals the formation pressure expressed in ppg gradient, these effective pressures are equal and there is no flow into or out of the well (i.e., "balanced").

Figure 4-8 shows that as the water flow rate increases from 30 to 70 gpm, the ECD in the example well increases from 5.9 to 7.7 ppg with an air flow rate of 60 scfm and from 5.2 to 6.9 gpm with 120 scfm. This broad range of ECDs would allow "balanced" foam drilling in most cases, since these ECDs are all considerably lower than the 8.34 ppg density of water.

Figure 4-9 shows that for the example well, the AFS motor power increases from 24 to 57 hp as the ECD increases from 5.2 to 6.9 ppg, because of the increased water flow rates (i.e., from 30 to 70 gpm).

Figure 4-10 shows that the AFS drilling rate increases from 44 to 102 ft/hr as the bottomhole ECD is increased from 5.2 to 6.9 ppg due to the increased motor power output.

Fig. 4-7. Drilling Rate

Fig. 4-8. Bottomhole ECD

Fig. 4-9. Motor Power vs. ECD

Fig. 4-10. Drilling Rate vs. ECD

Fig. 4-11. Cutting Velocity

Fig. 4-12. Foam Quality

CUTTINGS VELOCITY

Foams have excellent cuttings carrying capacities, with the cuttings velocity being nearly equal to the foam velocity. **Figure 4-11** shows that as the water flow rate increases from 30 to 70 gpm, the cuttings velocity increases from 61 to 176 ft/hr with 60 scfm air flow and from 75 to 192 ft/hr with 120 scfm air flow. These velocities are adequate to effectively clean the holes in all cases.

FOAM QUALITY

Foam quality is defined as the fractal percentage of air (by volume) in the foam. For example, a foam quality of 0 corresponds to 100 percent water and a foam quality of 1.0 corresponds to 100 percent air. With a foam, the water is the continuous phase and the air is entrained in the foam as small bubbles, similar to shaving cream. When the foam quality exceeds about 0.94, the water breaks out of the mixture and the air becomes the continuous phase with free water droplets, forming a "mist." The hole cleaning ability of a mist is considerably less than that of a foam, so hole cleaning problems often occurs in the upper portion of wells (e.g., 1,000 to 2,000 feet deep) where the mixture transitions from foam to mist.

Figure 4-12 shows with 120 scfm air circulation, the foam quality in the annulus at the surface decreases from 0.87 to 0.74 as the water flow rate increases from 30 to 70 gpm. This is ideal since field drillers like to keep the foam quality between 0.5 to 0.9.

Figure 4-12 shows that at the hole bottom, the foam quality decreases from 0.35 to 0.14 as the water flow rate increases from 30 to 70 gpm. The foam quality at the bottom of the annulus is low because the air is highly compressed and water constitutes most of the mixture volume. Hole cleaning can be a problem at the top of the drill collars where the annular area increases significantly at the drill collar-to-drillpipe transition, producing a significant reduction in the cuttings lifting velocity.

MOTOR PERFORMANCE

The performance of a positive-displacement motor is controlled primarily by its volumetric displacement, v , which is defined as the volume of water required to produce one rotation of the motor under no load conditions (i.e., no fluid leakage).

In oilfield terms, the motor torque, T , equals (Appendix A):

$$T = 3.064 \eta_m pv \quad (\text{ft-lbs}) \quad (4-3)$$

the rotary speed, N , equals:

$$N = \frac{\eta_h \Psi}{v} \quad (\text{rpm}) \quad (4-4)$$

and the power output, P, equals:

$$P = \frac{NT}{5,252} \quad (\text{hp}) \quad (4-5)$$

where

$$\begin{aligned} p &= \text{Motor Pressure Drop (psi)} \\ v &= \text{Volumetric Displacement (gal/rev)} \\ \eta_m &= \text{Motor Mechanical Efficiency } (\approx 0.88) \\ \eta_h &= \text{Motor Hydraulic Efficiency } (\approx 0.79) \\ \eta &= \eta_m \times \eta_h \end{aligned}$$

With 70 gpm and 2,000 psi motor pressure drop, the motor power output equals (Eq. 4-5):

$$P = \frac{0.79 \times 0.88 \times 2,000 \times 70}{1,714} = 56.8 \text{ hp}$$

Figure 4-13 shows how the motor rotary speed and torque can be varied by varying the motor volumetric displacement for constant motor power output (56.8 hp) and constant water flow rate (70 gpm).

Figure 4-14 and Figure 4-15 show that the motor speed will decrease from 616 to 205 rpm and the motor torque will increase from 484 to 1,452 ft-lbs as the motor volumetric displacement is increased from 0.1 to 0.3 gal/rev.

Appendix C lists volumetric displacements for 2 1/8- to 11 1/4-inch diameter PDM power sections manufactured by Moyno Oilfield Products, Houston, Texas. Motors manufactured by other companies have similar volumetric displacements because they are subject to the same diametral constraints.

DRILLING COSTS

The footage drilling cost, C, with a CT drilling rig equals:

$$C = \frac{C_b + (C_r + C_c + C_m)(t_r + t_t)}{R \times t_r} \quad (\$/\text{ft}) \quad (4-6)$$

where

$$\begin{aligned} C &= \text{Footage Drilling Cost } (\$/\text{ft}) \\ C_b &= \text{Bit Cost } (\$) \\ C_r &= \text{CT Rig Cost } (\$/\text{hr}) \\ C_c &= \text{Compressor Cost } (\$/\text{hr}) \\ C_m &= \text{Drilling Motor Cost } (\$/\text{hr}) \\ t_r &= \text{Rotating Time (Bit Life) (hrs)} \\ t_t &= \text{Trip Time (hrs)} \\ R &= \text{Drilling Rate (ft/hr)} \end{aligned}$$

The total hole making cost C_t equals:

$$C_t = C \times D \quad (\$) \quad (4-7)$$

where

D = Well Depth (ft)

The hole making cost typically constitutes about 50 percent of the total cost of the well with the remaining 50 percent going toward completion costs (casing, cementing, etc.).

The AFS can produce significant cost savings as shown for the following example well (Table 4-2).

TABLE 4-2. Example CT Wells

	Conventional Foam System	Advanced Foam System
Bit Cost C_b (\$)	5,000	5,000
CT Rig Cost C_r (\$/hr)	800	900*
Compressor Cost C_c (\$/hr)	300**	150
Drilling Motor Cost C_m (\$/hr)	300	300
Bit Life t_b (hrs)	50	40***
Trip Time t_t (hrs)	2	2
Drilling Rate R (ft/hr)	54	102
Well Depth (ft)	3,000	3,000

* Includes \$100/hr for Concentric CT

** Higher Compressor Cost due to Higher Air Pressure

*** Lower Bit Life due to Higher Motor Power

The drilling cost C for the *conventional* system equals:

$$C = \frac{5,000 + (800 + 300 + 300)(50 + 2)}{54 \times 50} = \$28.81/\text{ft}$$

and the total hole making cost C_t equals:

$$C_t = \$28.81 \times 3,000 = \$86,430$$

The drilling cost C for the AFS equals:

$$C = \frac{5,000 + (900 + 150 + 300)(50 + 2)}{102 \times 50} = \$14.75/\text{ft}$$

and the total hole making cost for the AFS equals:

$$C_t = \$14.75 \times 3,000 = \$44,250$$

This shows that the AFS will reduce the hole making cost by 49 percent (\$86,430 to \$44,250) and the overall well cost by approximately 24.5 percent since hole making constitutes about 50 percent of the well cost (Figure 4-16).

This is a major cost saving that could have a significant impact on the cost of producing geothermal and petroleum reservoirs.

Figure 4-13. Motor Characteristics

Figure 4-14. Motor Speed

Figure 4-15. Motor Torque

Figure 4-16. Drilling Cost Comparison

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Appendix A

Motor Efficiency and Performance Equations

NOMENCLATURE

- Q = Flow Rate (gpm)
v = Motor Volumetric Displacement (gal/rev)
T = Torque (ft-lbs)
N = Rotary Speed (rpm)
p = Pressure Drop (psi)
P = Power Output (hp)
 η_h = Hydraulic Efficiency (decimal)
 η_m = Mechanical Efficiency (decimal)
 η = Overall Efficiency (decimal) = ($\eta_h \times \eta_m$)

MOTOR EQUATIONS

The power input P to a downhole drilling motor equals:

$$P_{IN} = \frac{pQ}{1,714} \text{ (hp)} \quad (A-1)$$

and the power output P equals:

$$P = \frac{2\pi NT}{33,000} = \frac{NT}{5,252} \text{ (hp)} \quad (A-2)$$

where:

$$P = \eta_m \eta_h P_{IN} = \eta P_{IN} \text{ (hp)} \quad (A-3)$$

and

$$P = \eta_m \eta_h \frac{pQ}{1,714} = \eta \frac{pQ}{1,714} \text{ (hp)} \quad (A-4)$$

The rotary speed of the motor is often calculated as follows:

$$N = \frac{\eta_h Q}{v} \text{ (rpm)} \quad (\text{constant } \eta_h) \quad (A-5)$$

where the volumetric efficiency η_h corresponds to fluid leakage between the rotor and stator and is assumed to be constant. Eq. A-5 assumes constant η_h and is accurate only near normal motor operating conditions.

Substituting Eq. A-5 into Eq. A-4 and setting it equal to Eq. A-2 shows that:

$$T = 3.064 \eta_m p v \text{ (ft-lbs)} \quad (\text{A-6})$$

where the mechanical efficiency η_m corresponds to mechanical friction in the motor.

The motor volumetric displacement v is defined as the volume of fluid required to produce one revolution of the motor with no leakage and can be determined by flowing through the motor with no torque ($\Delta p = 0$). In this case, there is no fluid leakage and the hydraulic efficiency is 100 percent ($\eta_h = 1.0$) and the volumetric efficiency equals:

$$v = \frac{\text{Flow Rate (gpm)}}{\text{Rotary Speed (rpm)}} = (\text{gal/rev}) \quad (\text{A-7})$$

Example:

Rotary Speed (no load)	=	200 rpm @ 100 gpm (no torque)
Flow Rate (Q)	=	100 gpm
Pressure Drop (p)	=	1,000 psi
Mechanical efficiency (η_m)	=	0.90
Hydraulic Efficiency (η_h)	=	0.85
Overall Efficiency (η)	=	$\eta_h \times \eta_m = 0.85 \times 0.9 = 0.765$

$$v = \frac{100}{200} = 0.5 \text{ gal/rev}$$

$$N = \frac{0.85 \times 100}{0.5} = 170 \text{ ft-lbs}$$

$$T = 3.064 \times 0.9 \times 1,000 \times 0.5 = 1,378 \text{ ft-lbs}$$

$$P = \frac{170 \times 1,378}{5,252} = 44.6 \text{ hp}$$

COMMERCIAL MOTOR VOLUMETRIC DISPLACEMENTS

Table A-1 shows volumetric displacements for MOYNO Oilfield Products 1¾ to 11¼ inch PDM rotors and stators. The volumetric displacements of other companies motors are similar since they are all subjected to the same diametral constraints.

TABLE A-1. Multilobe Motor Volumetric Displacements*

Motor Diameter (inches)	Lobe Configuration	Volumetric Displacement**	
		gal/rev	cfm/rev
1.750	1/2	0.016 - 0.032	0.120 - 0.239
2.375	5/6	0.125 - 0.140	0.935 - 1.05
2.875	5/6, 7/8	0.166 - 0.300	1.24 - 2.24
3.375	4/5, 7/8	0.306 - 0.625	2.29 - 4.68
3.750	4/5, 7/8	0.625 - 1.176	4.68 - 8.80
4.75	4/5, 7/8	0.952 - 1.786	7.12 - 13.4
6.25	4/5, 7/8	1.520 - 2.941	11.4 - 22.0
6.75	4/5, 7/8	2.000 - 3.488	15.0 - 26.1
8.00	4/5, 7/8	4.000 - 6.250	29.9 - 46.8
9.625	3/4, 5/6	4.511 - 8.955	33.7 - 67.0
11.25	3/4	8.33	62.3

*Moyno Power Sections Brochure IMPTD1196 (1996), Moyno Oilfield Products, Houston, Texas.

**The higher values are for the higher lobe configurations.

COMMERCIAL MOTOR EFFICIENCIES

Table A-2 shows data for 13 different motors from four leading downhole motor companies. These data show that typical values for efficiencies are:

$$\begin{aligned}\eta_h &= 0.88 \\ \eta_m &= 0.79 \\ \eta &= 0.695\end{aligned}$$

These values should be used if actual values are not known.

TABLE A-2. Commercial PDM Motor Efficiencies

Company	Motor Type (S-L)*	Motor Diameter (in)	Flow Rate (gpm)	Motor Pressure (psi)	Motor Torque (ft-lbs)	Operating Speed (rpm)	No Load Speed (rpm)	Volumetric Displacement (gal/rev)	Input Power (hp)	Output Power (hp)	Overall Efficiency η	Hydraulic Efficiency η_H	Mechanical Efficiency η_M
Drilex	3-5/6	2.375	42	750	101	730	850	0.049	18.38	14.04	0.764	0.859	0.889
Drilex	2-9/10	3.5	110	700	405	380	400	0.275	44.92	29.30	0.652	0.950	0.687
Drilex	3-5/6	3.75	150	750	579	480	530	0.283	65.64	52.92	0.806	0.906	0.890
Navidrill	5/6	3.75	185	800	890	340	386	0.479	86.35	57.62	0.667	0.881	0.758
Navidrill	5/6	4.75	240	725	1180	300	341	0.704	101.52	67.40	0.664	0.880	0.755
Navidrill	5/6	6.75	475	725	2800	260	295	1.610	200.92	138.61	0.690	0.881	0.783
Trudrill	3.5-4/5	3.75	160	500	700	210	260	0.615	46.67	27.99	0.600	0.808	0.742
Trudrill	3.5-4/5	4.75	250	500	1140	235	265	0.943	72.93	51.01	0.699	0.887	0.789
Trudrill	4.3-4/5	6.75	400	610	2240	235	265	1.509	142.36	100.23	0.704	0.887	0.794
MOYNO	2.5-5/6	2.375	50	385	115	350	400	0.125	11.23	7.66	0.682	0.875	0.780
MOYNO	3.3-5/6	2.875	80	500	203	420	480	0.167	23.34	16.23	0.696	0.875	0.795
MOYNO	5-4/5	3.375	110	720	553	320	360	0.306	46.21	33.69	0.729	0.889	0.820
MOYNO	3.5-4/5	3.75	160	505	768	225	256	0.625	47.14	32.90	0.698	0.879	0.794

*S = Number Stages, L = Number Lobes

Using these efficiencies, Eqs. A-1 to A-6 equal:

$$P_{IN} = \frac{pQ}{1,714} \text{ (hp)} \quad (A-8)$$

$$P = \frac{2\pi NT}{33,000} = \frac{NT}{5,252} \text{ (hp)} \quad (A-9)$$

$$P = 0.695 \frac{pQ}{1,714} \text{ (hp)} \quad (A-10)$$

$$N = \frac{0.88Q}{v} \text{ (rpm)} \quad (A-11)$$

$$T = 2.421 pv \text{ (ft-lbs)} \quad (A-12)$$

a) Correct Rotary Speed Calculation (Variable Hydraulic Efficiency)

Some of the fluid pumped through a motor leaks past the rotor, so the effective fluid flow rate Q_{eff} powering to motor equals:

$$Q_{eff} = Q_t - Q_l \quad (gpm) \quad (A-13)$$

where:

Q_{eff} = Effective Flow Rate (gpm)

Q_t = Total Flow Rate (gpm)

Q_l = Leakage Flow Rate (gpm)

The leakage Q_l varies as:

$$Q_l = kp^2 \quad (A-14)$$

where k is a constant and p is the pressure drop across the motor. If the flow rate is varied with constant bit torque (i.e., constant motor pressure drop), Q_l will remain constant.

The rotary speed N equals:

$$N = \frac{Q_{\text{eff}}}{v} \quad (\text{rpm}) \quad (\text{A-15})$$

or

$$N = \frac{Q_t - Q_l}{v} \quad (\text{rpm}) \quad (\text{A-16})$$

where v is the motor volumetric displacement (gal/rev).

b) Incorrect Rotary Speed Calculation (Constant Hydraulic Efficiency)

If the hydraulic efficiency is assumed to be constant (Eq. A-5), the motor rotary speed equals:

$$N_{\text{opt}} = \frac{\eta_h}{v} Q_{\text{opt}} \quad (\text{rpm}) \quad (\text{A-17})$$

where N_{opt} and Q_{opt} correspond to the rotary speed and flow rate at optimum operating conditions, and η_h is the motor hydraulic efficiency.

Eq. A-17 equation is correct only for the optimum flow rate Q_{opt} since the hydraulic efficiency is a function of flow rate and decreases as the flow rate decreases. This can be shown as follows:

From Eq. A-17

$$\eta_h = \left(\frac{N_{\text{opt}}}{Q_{\text{opt}}} \right) v \quad (\text{A-18})$$

Substituting Eq. A-18 into Eq. A-5 shows that:

$$N = \left(\frac{N_{\text{opt}}}{Q_{\text{opt}}} \right) Q \quad (\text{A-19})$$

This equation shows that rotary speed is proportional to flow rate, which is incorrect.

EXAMPLE CALCULATION (Water Circulation)

Given (Constant Motor Pressure Drop)

Fluid	=	Water
v	=	0.125 gal/rev
Q	=	70 gpm (Optimum)
N	=	492.8 rpm (Optimum)
η_h	=	0.88 (Optimum)

Table A-3 shows that the actual rotary speed is lower than predicted by Eq. A-19, especially at lower flow rates where the leakage flow become a greater percentage of the total flow. This explains why motors stop rotating at low flow rates and why they perform poorly on air or nitrogen as shown in the next section.

TABLE A-3. Comparison of Rotary Speed Calculations (Water Circulation)

Total Flow Rate Q_t (gpm)	Leakage* Rate Q_l (gpm)	Effective Rate Q_{eff} (gpm)	Actual Rotary Speed (Eq. A-16) (rpm)	Incorrect Rotary Speed (Eq. A-19)
70	8.4	61.6	493	493
60	8.4	51.6	413	422
50	8.4	41.6	333	352
40	8.4	31.6	253	282
30	8.4	21.6	173	211
20	8.4	11.6	93	141
10	8.4	0	0	70
0	8.4	0	0	0

*70 (1-0.88) (Eq. A-14)

EXAMPLE CALCULATION (Air Flow)

Leakage with air circulation is much higher than with water circulation due to the lower viscosity of air, resulting in lower hydraulic efficiency at optimum conditions.

Below are calculations for the following air drilling conditions:

Given:

Fluid = Air
 $v = 0.125$ gal/rev
 $Q = 70$ gpm (9.36 scfm)
 $N = 392.8$ rpm
 $\eta_h = 0.70$

Table A-4 shows that actual rotary speed decreases dramatically as the flow rate decreases and that the air motor would stall when flow rate decreases to 20 gpm (2.67 scfm).

TABLE A-4. Comparison of Rotary Speed Calculations (Air Drilling)

Total Flow Rate Q_t (gpm)	Leakage* Flow Rate Q_l (gpm)	Effective Rate Q_{eff} (gpm)	Actual Rotary Speed (Eq. A-16) (rpm)	Incorrect Flow Speed (Eq. A-19) (rpm)
70	21	49	392	392
60	21	39	312	336
50	21	29	232	280
40	21	19	152	224
30	21	9	72	168
20	21	0	0	112
10	21	0	0	56
0	21	0	0	0

*70 (1-0.70) (Eq. A-14)

The results have been confirmed with air dynamometer tests on motors conducted at the Drilling Research Center (DRC) in Houston where the motors stalled when the air flow rates decreased to 30 to 40 percent of their normal values.

These examples show that Eq. A-19 gives results that are grossly in error at low flow rates with air or nitrogen.

The differences between these calculation methods increases as hydraulic efficiency decreases. If hydraulics efficiency is 1.0 (100% efficient), Eqs. A-16 and A-19 predict equal results since the leakage rates are both zero ($Q_l = 0$).

Appendix B

Drilling Rate and Specific Energy Equations

BASIC DRILLING RATE EQUATION

In oilfield units, bit power P equals:

$$P = \frac{2\pi NT}{33,000} \text{ (hp)} \quad (\text{B-1})$$

drilling rate R equals:

$$R = \frac{1.98 \times 10^6 P}{AE} = \frac{2.521 \times 10^6 P}{D^2 E} = \frac{480 NT}{D^2 E} \text{ (ft/hr)} \quad (\text{B-2})$$

and specific energy E equals:

$$E = \frac{2.521 \times 10^6 P}{D^2 R} = \frac{480 NT}{D^2 R} \text{ (psi)} \quad (\text{B-3})$$

where:

- A = Hole Area (in²)
- D = Bit Diameter (inches)
- E = Specific Energy at Operating Δp (psi)
- N = Rotary Speed (rpm)
- P = Bit Power (hp)
- R = Drilling Rate (ft/hr)
- T = Torque (ft-lbs)

Specific energy E is the energy required to remove a unit volume of rock at the field operating conditions (i.e., existing Δp differential pressure).

EXAMPLE CALCULATION

For a 3.75-inch bit ($D = 3.75$ inch) and a rock with a specific energy of 100,000 psi ($E = 100,000$ psi), Eq. B-2 reduces to:

$$R = 1.793 P \text{ (ft/hr)} \quad (\text{B-4})$$

Eq. B-4 shows that drilling rate R is proportional to bit or motor power and in this case increases 1.793 ft/hr for each additional horsepower of bit power. The 100,000 psi specific energy is typical for oilfield rocks, so Eq. B-4 is used in this study to calculate drilling rates for different foam drilling cases with 3¼-inch bits.

With 70 gpm and 120 scfm, the 3¾-inch motor delivers 56.8 hp to a 3¼-inch bit which corresponds to a drilling rate of:

$$R = 1.793 \times 56.8 = 102 \text{ (ft/hr)}$$

Appendix C

Effect of Differential Fluid Pressure on Drilling Rate

DIFFERENTIAL PRESSURE EFFECTS

Laboratory drilling tests conducted by Moffitt (1991), Cunningham and Eenink (1959), and other investigators show that drilling rate decreases about 70 percent as the differential fluid pressure Δp increases from 0 to 1,000 psi (Figure C-1) where:

$$\Delta p = p_f - p_w \quad (\text{psi}) \quad (\text{C-1})$$

where:

Δp = Differential Fluid Pressure (psi)

p_f = Formation Fluid Pressure (psi)

p_w = Wellbore Fluid Pressure (psi)

Figure C-1. Differential Pressure and Drilling Rate
(Moffitt, 1991)

Different curves were fitted to the Moffitt's laboratory drilling data to produce the typical normalized drilling rate curve shown in Figure C-2 and Table C-1.

The equation for this typical normalized drilling rate curve is:

$$\frac{R}{R_0} = 0.2341 + 4.862 / (1 + \exp((\Delta p + 1,316) / 784.8)) \quad (\text{C-2})$$

where:

R = Drilling Rate at Δp

R_o = Drilling Rate at $\Delta p = 0$

Δp = Differential Pressure (psi)

Eq. C-2 is used in this study to calculate drilling rates for different drilling conditions. Although it is not exact for all rocks, it gives a reasonable approximation for most oilfield rocks.

Figure C-2. Effect of Differential Pressure on Drilling Rate

TABLE C-1. NORMALIZED DRILLING RATE

Differential Pressure (psi)	Normalized Drilling Rate
0	1.00
50	0.96
100	0.92
200	0.85
300	0.78
400	0.72
500	0.67
750	0.56
1,000	0.48
1,250	0.41
1,500	0.36
1,750	0.33
2,000	0.30
2,500	0.27
3,000	0.25
5,000	0.24
10,000	0.23

GENERAL DRILLING RATE EQUATION

Combining Eqs. B-2 and C-2, drilling rate R equals:

$$R = \frac{2.521 \times 10^6 P}{D^2 E_0} [0.2341 + 4.862 / (1 + \exp((\Delta p + 1,316) / 784.8))] \text{ (ft/hr)} \quad (\text{C-3})$$

where:

- R = Drilling Rate (ft/hr)
- Δp = Differential Pressure (psi)
- P = Bit Power (hp)
- D = Bit Diameter (in)
- E_0 = Specific Energy at $\Delta p = 0$ psi

TYPICAL SPECIFIC ENERGIES

Table C-2 shows typical drilling data and specific energies for oilfield rocks.

TABLE C-2. Typical Oilfield Rock Specific Energies

Rock Type	Bit Diameter (D) (inches)	Drilling Rate (R) (ft/hr)	Bit Torque (T) (ft-lbs)	Rotary Speed (N) (rpm)	Specific* Energy (lb/in)
Soft Sandstone	4 3/4	100	700	100	14,900
Hard Sandstone	4 3/4	40	700	100	37,250
Limestone	4 3/4	20	700	100	74,500
Shale	4 3/4	10	700	100	149,000

*Sp. En. = 480 NT/D²R

This table shows that specific energies of oilfield rocks typically range from 15,000 to 150,000 psi.

BOTTOMHOLE DIFFERENTIAL FLUID PRESSURE CALCULATIONS

The fluid pressure, P_w , executed by a column of drilling fluid extending to the surface equals:

$$P_w = 0.052 \text{ wd} \quad (\text{psi}) \quad (\text{C-4})$$

and the differential pressure Δp , equals:

$$\Delta p = P_w - P_f \quad (\text{psi}) \quad (\text{C-5})$$

where:

- p_w = Wellbore Fluid Pressure (psi)
- p_f = Formation Fluid Pressure (psi)
- w = Mud Weight (ppg)
- d = Well Depth (ft)

Example Case:

For example, at 10,000 ft a 10 ppg mud will exert a pressure of:

$$P_w = 0.052 \times 10 \times 10,000 = 5,200 \text{ psi}$$

If the formation pressure at this depth equals 4,800 psi, the differential pressure with this 10 ppg mud will equal:

$$\Delta p = 5,200 - 4,800 = 400 \text{ psi}$$

Table C-1 shows that this 400 psi differential pressure will reduce the drilling rate by 28 percent.

If the mud weight is reduced from 10 ppg to 9.23 ppg, the wellbore pressure p_f equals:

$$p_f = 0.052 \times 9.23 \times 10,000 = 4,800 \text{ psi}$$

which exactly equals the formation fluid pressure so the Δp with this 9.23 ppg mud is zero:

$$\Delta p = 480 - 480 = 0 \text{ psi}$$

Reducing the mud weight from 10 ppg to 9.23 ppg will decrease the differential pressure from 400 to 0 psi which will increase the normalized drilling rate from 0.72 to 1.0, an increase of:

$$\text{Drilling Rate Increase} = \frac{100 (1 - 0.72)}{0.72} = 38.9\%$$

This large increase in drilling rate would significantly reduce drilling costs in most wells.

Appendix D
MUDLITE Foam Hydraulic Calculations

DOE EXAMPLE FOAM WELL (small CT)

Vertical well: TVD = 3000 (ft)

Choke press.: 50 (psi)

Outer CT: 2.375" * 0.156" wall I.D. = 2.063

Inner CT: 1.5" * 0.134" wall I.D. = 1.232

Foam Quality Range: 0.5 to 0.96

Equivalent parasite string ID = 0.816*(d2-d1) = 0.816*(2.063 - 1.5) = 0.563"

Bottomhole gas Injection.

3-3/4 inch

Bit Diameter:

2.375" * 0.156" wall I.D. = 2.063

1.5" * 0.134" wall I.D. = 1.232

Min. cuttings velocity: 50 ft/min

Liquid Rate (GPM)	Gas Inj. at BH (SCFM)	Pump Press (psi)	Comp. Press (psi)	Pipe P above mtr (psi)	Motor P. Drop (psi)	Motor Flow rate (gpm)	Motor Power In (hp)	Bit P. Drop (psi)	BH Press (psi)	BH ECD (ppg)	Surf. Foam Q. (-)	BH Foam Q. (-)	BH Ctgs. Vel (ft/min)	BH Fl. Vel (ft/min)
30	60	867	930	1925	1000	30	17.5	6.3	919	5.89	0.78	0.2	61	109
40	60	1124	1015	2017	1000	40	23.3	11.2	1005	6.44	0.72	0.14	90	136
50	60	1404	1089	2098	1000	50	29.2	17.5	1080	6.92	0.68	0.11	120	164
60	60	1712	1152	2169	1000	60	35.0	25.1	1144	7.33	0.64	0.09	148	192
70	60	2046	1206	2232	1000	70	40.8	34.2	1198	7.68	0.6	0.07	176	220
30	120	753	846	1811	1000	30	17.5	6.3	805	5.16	0.87	0.35	75	134
40	120	990	910	1884	1000	40	23.3	11.2	873	5.6	0.83	0.27	108	159
50	120	1269	978	1962	1000	50	29.2	17.5	945	6.05	0.80	0.21	136	185
60	120	1583	1045	2040	1000	60	35.0	25.1	1015	6.5	0.77	0.17	164	211
70	120	1930	1109	2116	1000	70	40.8	34.2	1081	6.93	0.74	0.14	192	238
70	120	2230	1109	2416	1300	70	53.1	34.2	1081	6.93	0.74	0.14	192	238
70	120	2530	1109	2716	1600	70	65.3	34.2	1081	6.93	0.74	0.14	192	238
30	60	1867	930	2925	2000	30	35.0	6.3	919	5.89	0.78	0.2	61	109
40	60	2124	1015	3017	2000	40	46.7	11.2	1005	6.44	0.72	0.14	90	136
50	60	2404	1089	3098	2000	50	58.3	17.5	1080	6.92	0.68	0.11	120	164
60	60	2712	1152	3169	2000	60	70.0	25.1	1144	7.33	0.64	0.09	148	192
70	60	3046	1206	3232	2000	70	81.7	34.2	1198	7.68	0.6	0.07	176	220
30	120	1753	846	2811	2000	30	35.0	6.3	805	5.16	0.87	0.35	75	134
40	120	1990	910	2884	2000	40	46.7	11.2	873	5.6	0.83	0.27	108	159
50	120	2269	978	2962	2000	50	58.3	17.5	945	6.05	0.80	0.21	136	185
60	120	2583	1045	3040	2000	60	70.0	25.1	1015	6.5	0.77	0.17	164	211
70	120	2930	1109	3116	2000	70	81.7	34.2	1081	6.93	0.74	0.14	192	238

DOE EXAMPLE FOAM WELL (small CT)

Vertical well: TVD = 3000 (ft)

Choke press.: 50 (psi)

Outer CT:

Inner CT:

Foam Quality Range:

Equivalent parasite string ID = $0.816 \cdot (d_2 - d_1) = 0.816 \cdot (2.063 - 1.5) = 0.563$ "

Bit Diameter:

2.375" * 0.156" wall

1.5" * 0.134" wall

0.5 to 0.96

Bottomhole gas injection.

3-3/4 inch

I.D. = 2.063

I.D. = 1.232

Min. cuttings velocity: 50 ft/min

BH Fl. Vel (ft/min)	Motor Vol. Displac. (gal/rev)	Motor Mech. Eff. (~0.79)	Motor Hyd. Eff. (~0.88)	Motor Overall Eff. (Decimal)	Rotary Speed (rpm)	Motor Torque (ft-lbf)	Motor Power Output (hp)	Rock Sp. Energy (psi)	Bit Diameter (in)	Drilling Rate (ft/hr)
109	0.125	0.79	0.88	0.6952	211	303	12.17	100000	3.75	21.8
136	0.125	0.79	0.88	0.6952	282	303	16.22	100000	3.75	29.1
164	0.125	0.79	0.88	0.6952	352	303	20.28	100000	3.75	36.4
192	0.125	0.79	0.88	0.6952	422	303	24.33	100000	3.75	43.6
220	0.125	0.79	0.88	0.6952	493	303	28.39	100000	3.75	50.9
134	0.125	0.79	0.88	0.6952	211	303	12.17	100000	3.75	21.8
159	0.125	0.79	0.88	0.6952	282	303	16.22	100000	3.75	29.1
185	0.125	0.79	0.88	0.6952	352	303	20.28	100000	3.75	36.4
211	0.125	0.79	0.88	0.6952	422	303	24.33	100000	3.75	43.6
238	0.125	0.79	0.88	0.6952	493	303	28.39	100000	3.75	50.9
238	0.125	0.79	0.88	0.6952	493	393	36.91	100000	3.75	66.2
238	0.125	0.79	0.88	0.6952	493	484	45.42	100000	3.75	81.4
109	0.125	0.79	0.88	0.6952	211	605	24.33	100000	3.75	43.6
136	0.125	0.79	0.88	0.6952	282	605	32.45	100000	3.75	58.2
164	0.125	0.79	0.88	0.6952	352	605	40.56	100000	3.75	72.7
192	0.125	0.79	0.88	0.6952	422	605	48.67	100000	3.75	87.2
220	0.125	0.79	0.88	0.6952	493	605	56.78	100000	3.75	101.8
134	0.125	0.79	0.88	0.6952	211	605	24.33	100000	3.75	43.6
159	0.125	0.79	0.88	0.6952	282	605	32.45	100000	3.75	58.2
185	0.125	0.79	0.88	0.6952	352	605	40.56	100000	3.75	72.7
211	0.125	0.79	0.88	0.6952	422	605	48.67	100000	3.75	87.2
238	0.125	0.79	0.88	0.6952	493	605	56.78	100000	3.75	101.8

Note: * = Input data

$D = B \cdot C$ $E = C \cdot (GPM)/A$

$F = 3.064 \cdot A \cdot (DP) \cdot B$

$G = E \cdot F / 5252$

$J = 2.521 \cdot 10^6 \cdot G / I^2 / H$

DOE EXAMPLE FOAM WELL

Vertical well: TVD = 3000 (ft)

Choke press. = 50 (psi)

CT: 2.000" * 0.134" wall

Foam Quality Range:

0.5 to 0.96

Normal surface gas injection.

Bit Diameter:

I.D. = 1.732"

Min. cuttings velocity: 50 ft/min

Liquid Rate (GPM)	Gas Inj. at BH (SCFM)	Pump/Comp. Press (psi)	Pipe P above mtr (psi)	Motor P. Drop (psi)	Motor Flow rate (gpm)	Motor Power In (hp)	Bit P. Drop (psi)	BH Press (psi)	BH ECD (ppg)	Surf. Foam Q. (-)	BH Foam Q. (-)	BH Ctgs. Vel (ft/min)	BH Fl. Vel (ft/min)
30	60	801	1945	1000	32	19	7.6	937	6.01	0.77	0.155	41	87
30	120	769	1801	1000	35	20	9.5	791	5.07	0.87	0.314	54	107
40	60	888	2030	1000	42	25	12.7	1018	6.52	0.71	0.109	66	110
40	120	821	1873	1000	45	26	15.1	858	5.5	0.83	0.236	78	127
50	60	982	2102	1000	52	30	19.3	1083	6.94	0.67	0.08	89	133
50	120	897	1944	1000	54	32	21.9	922	5.91	0.8	0.183	102	150
60	60	1078	2164	1000	62	36	27.2	1137	7.29	0.62	0.07	114	157
60	120	987	2012	1000	64	37	30.1	982	6.29	0.77	0.15	126	172
70	60	1177	2217	1000	72	42	36.5	1181	7.57	0.05	0.59	138	180
70	120	1088	2077	1000	74	43	39.6	1037	6.65	0.74	0.12	149	194

70	120	1370	2377	1300	74	56	39.6	1037	6.65	0.74	0.12	149	194
70	120	1660	2677	1600	74	69	39.6	1037	6.65	0.74	0.12	149	194

30	60	1746	2945	2000	32	37	7.6	937	6.01	0.77	0.155	41	87
30	120	1656	2801	2000	33	39	9.5	791	5.07	0.87	0.314	54	107
40	60	1852	3030	2000	42	49	12.7	1018	6.52	0.71	0.109	66	110
40	120	1738	2873	2000	44	51	15.1	858	5.5	0.83	0.236	78	127
50	60	1956	3102	2000	52	61	19.3	1083	6.94	0.67	0.08	89	133
50	120	1835	2944	2000	53	62	21.9	922	5.91	0.8	0.183	102	150
60	60	2059	3164	2000	62	72	27.2	1137	7.29	0.624	0.07	114	157
60	120	1941	3012	2000	63	74	30.1	982	6.29	0.77	0.15	126	172
70	60	2163	3217	2000	72	84	36.5	1181	7.57	0.59	0.05	138	180
70	120	2053	3077	2000	73	85	39.6	1037	6.65	0.74	0.12	149	194

DOE EXAMPLE FOAM WELL

Vertical well: TVD = 3000 (ft)

Choke press. = 50 (psi)

CT: 2.000" * 0.134" wall

Foam Quality Range:

0.5 to 0.96

Normal surface gas injection.

Bit Diameter:

I.D. = 1.732"

Min. cuttings velocity: 50 ft/min

	A*	B*	C*	D	E	F	G	H*	I*	J
BH Fl. Vel (ft/min)	Motor Vol. Displac. (gal/rev)	Motor Mech. Eff. (~0.79)	Motor Hyd. Eff. (~0.88)	Motor Overall Eff. (Decimal)	Rotary Speed (rpm)	Motor Torque (ft-lbf)	Motor Power Output (hp)	Rock Sp. Energy (psi)	Bit Diameter (in)	Drilling Rate (ft/hr)
87	0.125	0.79	0.88	0.6952	225	303	12.98	100000	3.75	23.3
107	0.125	0.79	0.88	0.6952	246	303	14.20	100000	3.75	25.4
110	0.125	0.79	0.88	0.6952	296	303	17.03	100000	3.75	30.5
127	0.125	0.79	0.88	0.6952	317	303	18.25	100000	3.75	32.7
133	0.125	0.79	0.88	0.6952	366	303	21.09	100000	3.75	37.8
150	0.125	0.79	0.88	0.6952	380	303	21.90	100000	3.75	39.3
157	0.125	0.79	0.88	0.6952	436	303	25.15	100000	3.75	45.1
172	0.125	0.79	0.88	0.6952	451	303	25.96	100000	3.75	46.5
180	0.125	0.79	0.88	0.6952	507	303	29.20	100000	3.75	52.3
194	0.125	0.79	0.88	0.6952	521	303	30.01	100000	3.75	53.8

194	0.125	0.79	0.88	0.6952	521	393	39.02	100000	3.75	69.9
194	0.125	0.79	0.88	0.6952	521	484	48.02	100000	3.75	86.1

87	0.125	0.79	0.88	0.6952	225	605	25.96	100000	3.75	46.5
107	0.125	0.79	0.88	0.6952	232	605	26.77	100000	3.75	48.0
110	0.125	0.79	0.88	0.6952	296	605	34.07	100000	3.75	61.1
127	0.125	0.79	0.88	0.6952	310	605	35.69	100000	3.75	64.0
133	0.125	0.79	0.88	0.6952	366	605	42.18	100000	3.75	75.6
150	0.125	0.79	0.88	0.6952	373	605	42.99	100000	3.75	77.1
157	0.125	0.79	0.88	0.6952	436	605	50.29	100000	3.75	90.2
172	0.125	0.79	0.88	0.6952	444	605	51.10	100000	3.75	91.6
180	0.125	0.79	0.88	0.6952	507	605	58.40	100000	3.75	104.7
194	0.125	0.79	0.88	0.6952	514	605	59.21	100000	3.75	106.2

$$D = B * C \quad E = C * (GPM) / A$$

$$F = 3.064 * A * (DP) * B$$

$$G = E * F / 5252$$

$$J = 2.521 * 10^6 * G / I^{1/2} / H$$

DOE EXAMPLE FOAM WELL (Pump/Compressor pressure is about 1100 psi)

Vertical well: TVD = 3000 (ft) Normal surface gas injection.
 Choke press. = 50 (psi) Bit Diameter: 3-3/4 inch
 CT: 2.000" * 0.134" wall I.D. = 1.732"
 Foam Quality Range: 0.5 to 0.96 Min. cuttings velocity: 50 ft/min

Liquid Rate (GPM)	Gas Inj. at BH (SCFM)	Pump/Comp. Press (psi)	Pipe P above mtr (psi)	Motor P. Drop (psi)	Motor Flow rate (gpm)	Motor Power In (hp)	Bit P. Drop (psi)	BH Press (psi)	BH ECD (ppg)	Surf. Foam Q. (-)	BH Foam Q. (-)	BH Ctgs. Vel (ft/min)	BH Fl. Vel (ft/min)
30	60	1118	2295	1350	32	25	7.6	937	6.01	0.77	0.155	41	87
30	120	1098	2201	1400	35	29	9.5	791	5.07	0.87	0.314	54	107
40	60	1097	2255	1225	42	30	12.7	1018	6.52	0.71	0.109	66	110
40	120	1122	2223	1350	45	35	15.1	858	5.5	0.83	0.236	78	127
50	60	1100	2227	1125	52	34	19.3	1083	6.94	0.67	0.08	89	133
50	120	1095	2169	1225	54	39	21.9	922	5.91	0.8	0.183	102	150
60	60	1102	2189	1025	62	37	27.2	1137	7.29	0.62	0.07	114	157
60	120	1100	2137	1125	64	42	30.1	982	6.29	0.77	0.15	126	172
70	60	1105	2142	925	72	39	36.5	1181	7.57	0.59	0.05	138	180
70	120	1101	2092	1015	74	44	39.6	1037	6.65	0.74	0.12	149	194

DOE EXAMPLE FOAM WELL

Vertical well: TVD = 3000 (ft)
 Choke press. = 50 (psi)
 CT: 2.000" * 0.134" wall
 Foam Quality Range:

Normal surface gas Injection.

Bit Diameter: 3-3/4 inch

I.D. = 1.732"

0.5 to 0.96

Min. cuttings velocity: 50 ft/min

BH. Fl. Vel (ft/min)	Motor Vol. Displac. (gal/rev)	Motor Mech. Eff. (~0.79)	Motor Hyd. Eff. (~0.88)	Motor Overall Eff. (Decimal)	Rotary Speed (rpm)	Motor Torque (ft-lbf)	Motor Power Output (hp)	Rock Sp. Energy (psi)	Bit Diameter (in)	Drilling Rate (ft/hr)
87	0.125	0.79	0.88	0.6952	225	408	17.52	100000	3.75	31.4
107	0.125	0.79	0.88	0.6952	246	424	19.87	100000	3.75	35.6
110	0.125	0.79	0.88	0.6952	296	371	20.87	100000	3.75	37.4
127	0.125	0.79	0.88	0.6952	317	408	24.64	100000	3.75	44.2
133	0.125	0.79	0.88	0.6952	366	340	23.73	100000	3.75	42.5
150	0.125	0.79	0.88	0.6952	380	371	26.83	100000	3.75	48.1
157	0.125	0.79	0.88	0.6952	436	310	25.77	100000	3.75	46.2
172	0.125	0.79	0.88	0.6952	451	340	29.20	100000	3.75	52.3
180	0.125	0.79	0.88	0.6952	507	280	27.01	100000	3.75	48.4
194	0.125	0.79	0.88	0.6952	521	307	30.46	100000	3.75	54.6

Note:

* = Input data

$$D = B * C \quad E = C * (GPM) / A$$

$$F = 3.064 * A * (DP) * B$$

$$G = E * F / 5252$$

$$J = 2.521 * 10^6 * G / I^2 / H$$

DOE EXAMPLE FOAM WELL

Vertical well: TVD = 6000 (ft)

Choke press. = 50 (psi)

Bit Diameter: 3-3/4 inch

Foam Quality Range: 0.5 to 0.96

Min. cuttings velocity: 50 ft/min

Bottomhole gas Injection

Outer CT: 2.375" * 0.156" wall I.D. = 2.063

Inner CT: 1.5" * 0.134" wall I.D. = 1.232

Liquid Rate (GPM)	Gas Inj. at BH (SCFM)	Pump Press (psi)	Comp. Press (psi)	Pipe P above mtr (psi)	Motor P. Drop (psi)	Motor Flow rate (gpm)	Motor Power In (hp)	Bit P. Drop (psi)	BH Press (psi)	BH ECD (ppg)	Surf. Foam Q. (-)	BH Foam Q. (-)	BH Ctgs. Vel (ft/min)
30	60	1965	2084	4082	2000	30	35	6.3	2075	6.65	0.78	0.104	54
30	120	1703	1847	3820	2000	30	35	6.3	1814	5.81	0.87	0.201	62
70	120	3997	2361	4369	2000	70	82	34.2	2335	7.48	0.74	0.077	177

Normal surface gas Injection

CT: 2.000" * 0.134" wall I.D. = 1.732"

Liquid Rate (GPM)	Gas Inj. at BH (SCFM)	Pump/Comp. Press (psi)	Pipe P above mtr (psi)	Motor P. Drop (psi)	Motor Flow rate (gpm)	Motor Power In (hp)	Bit P. Drop (psi)	BH Press (psi)	BH ECD (ppg)	Surf. Foam Q. (-)	BH Foam Q. (-)	BH Ctgs. Vel (ft/min)	BH Fl. Vel (ft/min)
30	60	1746	4148	2000	32	37	6.9	2141	6.86	0.77	0.077	37	80
30	120	1577	3870	2000	33	39	7.8	1862	5.97	0.87	0.161	41	87
70	120	2275	4328	2000	73	85	37.1	2291	7.34	0.74	0.063	140	182

DOE EXAMPLE FOAM WELL

Vertical well: TVD = 6000 (ft)

Choke press. = 50 (psi)

CT: 2.000" * 0.134" wall

Foam Quality Range:

0.5 to 0.96

Bit Diameter:

3-3/4 inch

I.D. = 1.732"

Min. cuttings velocity: 50 ft/min

	A*	B*	C*	D	E	F	G	H*	I*	J
BH Fl. Vel (ft/min)	Motor Vol. Displac. (gal/rev)	Motor Mech. Eff. (~0.79)	Motor Hyd. Eff. (~0.88)	Motor Overall Eff. (Decimal)	Rotary Speed (rpm)	Motor Torque (ft-lbf)	Motor Power Output (hp)	Rock Spc. Energy (psi)	Bit Diameter (in)	Drilling Rate (ft/hr)
98	0.125	0.79	0.88	0.6952	211	605	24.33	100000	3.75	43.6
110	0.125	0.79	0.88	0.6952	211	605	24.33	100000	3.75	43.6
221	0.125	0.79	0.88	0.6952	493	605	56.78	100000	3.75	101.8

BH Fl. Vel (ft/min)	Motor Vol. Displac. (gal/rev)	Motor Mech. Eff. (~0.79)	Motor Hyd. Eff. (~0.88)	Motor Overall Eff. (Decimal)	Rotary Speed (rpm)	Motor Torque (ft-lbf)	Motor Power Output (hp)	Rock Spc. Energy (psi)	Bit Diameter (in)	Drilling Rate (ft/hr)
80	0.125	0.79	0.88	0.6952	225	605	25.96	100000	3.75	46.5
87	0.125	0.79	0.88	0.6952	232	605	26.77	100000	3.75	48.0
182	0.125	0.79	0.88	0.6952	514	605	59.21	100000	3.75	106.2

$$D = B * C \quad E = C * (GPM) / A$$

$$F = 3.064 * A * (DP) * B$$

$$G = E * F / 5252$$

$$J = 2.521 * 10^6 * G / I^2 / H$$

DOE EXAMPLE FOAM WELL

Vertical well: TVD = 3000 (ft)

Bottomhole gas injection.

Choke press. = 50 (psi)

Bit Diameter: 3-3/4 inch

Outer CT: 2.875" * 0.188" wall

I.D. = 2.499

Inner CT: 1.75" * 0.134" wall

I.D. = 1.482

Foam Quality Range: 0.5 to 0.96

Min. cuttings velocity: 50 ft/min

Equivalent parasite string ID = $0.816 \cdot (d_2 - d_1) = 0.816 \cdot (2.499 - 1.75) = 0.6112$ "

Liquid Rate (GPM)	Gas Inj. at BH (SCFM)	Pump Press (psi)	Comp. Press (psi)	Pipe P above mtr (psi)	Motor P. Drop (psi)	Motor Flow rate (gpm)	Motor Power In (hp)	Bit P. Drop (psi)	BH Press (psi)	BH ECD (ppg)	Surf. Foam Q. (-)	BH Foam Q. (-)	BH Ctgs. Vel (ft/min)	BH Fl. Vel (ft/min)
30	60	832	1034	2034	1000	30	17.5	6.3	1028	6.59	0.78	0.18	108	155
30	120	763	981	1965	1000	30	17.5	6.3	958	6.14	0.87	0.31	131	183
40	60	1017	1145	2151	1000	40	23.3	11.2	1139	7.3	0.72	0.13	149	194
40	120	937	1080	2072	1000	40	23.3	11.2	1060	6.8	0.83	0.23	171	220
50	60	1210	1249	2261	1000	50	29.2	17.5	1244	7.97	0.68	0.10	190	234
50	120	1137	1188	2189	1000	50	29.2	17.5	1171	7.51	0.80	0.18	210	257

Liquid Rate (GPM)	Gas Inj. at BH (SCFM)	Pump Press (psi)	Comp. Press (psi)	Pipe P above mtr (psi)	Motor P. Drop (psi)	Motor Flow rate (gpm)	Motor Power (hp)	Bit P. Drop (psi)	BH Press (psi)	BH ECD (ppg)	Surf. Foam Q. (-)	BH Foam Q. (-)	BH Ctgs. Vel (ft/min)	BH Fl. Vel (ft/min)
30	60	832	1034	3034	2000	30	35.0	6.3	1028	6.59	0.78	0.18	108	155
30	120	763	981	2965	2000	30	35.0	6.3	958	6.14	0.87	0.31	131	183
40	60	1017	1145	3151	2000	40	46.7	11.2	1139	7.3	0.72	0.13	149	194
40	120	937	1080	3072	2000	40	46.7	11.2	1060	6.8	0.83	0.23	171	220
50	60	1210	1249	3261	2000	50	58.3	17.5	1244	7.97	0.68	0.10	190	234
50	120	2137	1188	3189	2000	50	58.3	17.5	1171	7.51	0.80	0.18	210	257

DOE EXAMPLE FOAM WELL

Vertical well: TVD = 3000 (ft)

Bottomhole gas injection.

Choke press. = 50 (psi)

Bit Diameter: 3-3/4 inch
 Outer CT: 2.875" * 0.188" wall I.D. = 2.499
 Inner CT: 1.75" * 0.134" wall I.D. = 1.482
 Foam Quality Range: 0.5 to 0.96
 Min. cuttings velocity: 50 ft/min

Equivalent parasite string ID = $0.816 \cdot (d_2 - d_1) = 0.816 \cdot (2.499 - 1.75) = 0.6112$ "

	A*	B*	C*	D	E	F	G	H*	I*	J
BH Fl. Vel (ft/min)	Motor Vol. Displac. (gal/rev)	Motor Mech. Eff. (~0.79)	Motor Hyd. Eff. (~0.88)	Motor Overall Eff. (Decimal)	Rotary Speed (rpm)	Motor Torque (ft-lbf)	Motor Power Output (hp)	Rock Spc. Energy (psi)	Bit Diameter (in)	Drilling Rate (ft/hr)
155	0.125	0.79	0.88	0.6952	211	303	12.17	100000	3.75	21.8
183	0.125	0.79	0.88	0.6952	211	303	12.17	100000	3.75	21.8
194	0.125	0.79	0.88	0.6952	282	303	16.22	100000	3.75	29.1
220	0.125	0.79	0.88	0.6952	282	303	16.22	100000	3.75	29.1
234	0.125	0.79	0.88	0.6952	352	303	20.28	100000	3.75	36.4
257	0.125	0.79	0.88	0.6952	352	303	20.28	100000	3.75	36.4

BH Fl. Vel (ft/min)	Motor Vol. Displac. (gal/rev)	Motor Mech. Eff. (~0.79)	Motor Hyd. Eff. (~0.88)	Motor Overall Eff. (Decimal)	Rotary Speed (rpm)	Motor Torque (ft-lbf)	Motor Power Output (hp)	Rock Spc. Energy (psi)	Bit Diameter (in)	Drilling Rate (ft/hr)
155	0.125	0.79	0.88	0.6952	211	605	24.33	100000	3.75	43.6
183	0.125	0.79	0.88	0.6952	211	605	24.33	100000	3.75	43.6
194	0.125	0.79	0.88	0.6952	282	605	32.45	100000	3.75	58.2
220	0.125	0.79	0.88	0.6952	282	605	32.45	100000	3.75	58.2
234	0.125	0.79	0.88	0.6952	352	605	40.56	100000	3.75	72.7
257	0.125	0.79	0.88	0.6952	352	605	40.56	100000	3.75	72.7

Note: * = Input data

$D = B \cdot C$ $E = C \cdot (GPM)/A$

$F = 3.064 \cdot A \cdot (DP) \cdot B$

$G = E \cdot F / 5252$

$J = 2.521 \cdot 10^6 \cdot G / I^2 / H$

DOE EXAMPLE WATER WELL

Vertical well: TVD = 3000 (ft)

Water only injection

Choke press. = 50 (psi)

Bit Diameter: 3-3/4 inch
 CT: 2.000" * 0.134" wall
 Foam Quality Range: 0.5 to 0.96
 Min. cuttings velocity: 50 ft/min

I.D. = 1.732"

Liquid Rate (GPM)	Gas Inj. at BH (SCFM)	Pump Press (psi)	Pipe P above mtr (psi)	Motor P. Drop (psi)	Motor Flow rate (gpm)	Motor Power In (hp)	Bit P. Drop (psi)	BH Press (psi)	BH ECD (ppg)	Surf. Foam Q. (-)	BH Foam Q. (-)	BH Ctgs. Vel (ft/min)	BH Fl. Vel (ft/min)
30	N/A	1118	2373	1000	30	18	6.3	1366	8.76	0	0	32	73
40	N/A	1158	2381	1000	40	23	11.2	1370	8.78	0	0	57	97
50	N/A	1208	2392	1000	50	29	17.5	1374	8.81	0	0	81	122
60	N/A	1268	2405	1000	60	35	25.1	1380	8.85	0	0	105	146
70	N/A	1337	2422	1000	70	41	34.2	1387	8.89	0	0	129	170

Liquid Rate (GPM)	Gas Inj. at BH (SCFM)	Pump Press (psi)	Pipe P above mtr (psi)	Motor P. Drop (psi)	Motor Flow rate (gpm)	Motor Power In (hp)	Bit P. Drop (psi)	BH Press (psi)	BH ECD (ppg)	Surf. Foam Q. (-)	BH Foam Q. (-)	BH Ctgs. Vel (ft/min)	BH Fl. Vel (ft/min)
30	N/A	2118	3373	2000	30	35	6.3	1366	8.76	0	0	32	73
40	N/A	2158	3381	2000	40	47	11.2	1370	8.78	0	0	57	97
50	N/A	2208	3392	2000	50	58	17.5	1374	8.81	0	0	81	122
60	N/A	2268	3405	2000	60	70	25.1	1380	8.85	0	0	105	146
50	N/A	2337	3422	2000	70	82	34.2	1387	8.89	0	0	129	170

DOE EXAMPLE WATER WELL

Vertical well: TVD = 3000 (ft)

Water only injection

Choke press. = 50 (psi)

Bit Diameter: 3-3/4 inch
 CT: 2.000" * 0.134" wall
 Foam Quality Range: 0.5 to 0.96
 Min. cuttings velocity: 50 ft/min

I.D. = 1.732"

	A*	B*	C*	D	E	F	G	H*	I*	J
BH Fl. Vel (ft/min)	Motor Vol. Displac. (gal/rev)	Motor Mech. Eff. (~0.79)	Motor Hyd. Eff. (~0.88)	Motor Overall Eff. (Decimal)	Rotary Speed (rpm)	Motor Torque (ft-lbf)	Motor Power Output (hp)	Rock Spc. Energy (psi)	Bit Diameter (in)	Drilling Rate (ft/hr)
73	0.125	0.79	0.88	0.6952	211	303	12.17	100000	3.75	21.8
97	0.125	0.79	0.88	0.6952	282	303	16.22	100000	3.75	29.1
122	0.125	0.79	0.88	0.6952	352	303	20.28	100000	3.75	36.4
146	0.125	0.79	0.88	0.6952	422	303	24.33	100000	3.75	43.6
170	0.125	0.79	0.88	0.6952	493	303	28.39	100000	3.75	50.9

BH Fl. Vel (ft/min)	Motor Vol. Displac. (gal/rev)	Motor Mech. Eff. (~0.79)	Motor Hyd. Eff. (~0.88)	Motor Overall Eff. (Decimal)	Rotary Speed (rpm)	Motor Torque (ft-lbf)	Motor Power Output (hp)	Rock Spc. Energy (psi)	Bit Diameter (in)	Drilling Rate (ft/hr)
73	0.125	0.79	0.88	0.6952	211	605	24.33	100000	3.75	43.6
97	0.125	0.79	0.88	0.6952	282	605	32.45	100000	3.75	58.2
122	0.125	0.79	0.88	0.6952	352	605	40.56	100000	3.75	72.7
146	0.125	0.79	0.88	0.6952	422	605	48.67	100000	3.75	87.2
170	0.125	0.79	0.88	0.6952	493	605	56.78	100000	3.75	101.8

Note:

* = Input data

$$D = B * C \quad E = C * (GPM) / A$$

$$F = 3.064 * A * (DP) * B$$

$$G = E * F / 5252$$

$$J = 2.521 * 10^6 * G / I^{1/2} / H$$

DOE EXAMPLE FOAM WELL

Horizontal well: TVD = 3000 (ft), Hori. Disp. = 3000 (ft)

Bottomhole gas injection.

Choke press. = 50 (psi)

Bit Diameter: 3-3/4 inch
 Outer CT: 2.875" * 0.188" wall
 Inner CT: 1.75" * 0.134" wall
 Foam Quality Range: 0.5 to 0.96
 Min. cuttings velocity: 50 ft/min

I.D. = 2.499

I.D. = 1.482

Equivalent parasite string ID = $0.816 \cdot (d_2 - d_1) = 0.816 \cdot (2.499 - 1.75) = 0.6112$ "

Liquid Rate (GPM)	Gas Inj. at BH (SCFM)	Pump Press (psi)	Comp. Press (psi)	Pipe P above mtr (psi)	Motor P. Drop (psi)	Motor Flow rate (gpm)	Motor Power In (hp)	Bit P. Drop (psi)	BH Press (psi)	BH ECD (ppg)	Surf. Foam Q. (-)	BH Foam Q. (-)	BH Ctgs. Vel (ft/min)	BH Fl. Vel (ft/min)
30	60	973	1093	2088	1000	30	17.5	6.3	1082	6.94	0.78	0.17	106	153
30	120	918	1063	2033	1000	30	17.5	6.3	1027	6.58	0.87	0.29	128	180
40	60	1242	1229	2232	1000	40	23.3	11.2	1220	7.82	0.72	0.12	147	192
40	120	1179	1188	2169	1000	40	23.3	11.2	1157	7.42	0.83	0.21	166	215
50	60	1538	1364	2374	1000	50	29.2	17.5	1356	8.7	0.68	0.09	188	232
50	120	1482	1327	2318	1000	50	29.2	17.5	1300	8.34	0.8	0.17	205	252

Liquid Rate (GPM)	Gas Inj. at BH (SCFM)	Pump Press (psi)	Comp. Press (psi)	Pipe P above mtr (psi)	Motor P. Drop (psi)	Motor Flow rate (gpm)	Motor Power In (hp)	Bit P. Drop (psi)	BH Press (psi)	BH ECD (ppg)	Surf. Foam Q. (-)	BH Foam Q. (-)	BH Ctgs. Vel (ft/min)	BH Fl. Vel (ft/min)
30	60	1973	1093	3088	2000	30	35.0	6.3	1082	6.94	0.78	0.17	106	153
30	120	1918	1063	3033	2000	30	35.0	6.3	1027	6.58	0.87	0.29	128	180
40	60	2242	1229	3232	2000	40	46.7	11.2	1220	7.82	0.72	0.12	147	192
40	120	2179	1188	3169	2000	40	46.7	11.2	1157	7.42	0.83	0.21	166	215
50	60	2538	1364	3374	2000	50	58.3	17.5	1356	8.7	0.68	0.09	188	232
50	120	2482	1327	3318	2000	50	58.3	17.5	1300	8.34	0.8	0.17	205	252

DOE EXAMPLE FOAM WELL

Horizontal well: TVD = 3000 (ft), Hori. Disp. = 3000 (ft)

Bottomhole gas injection.

Choke press. = 50 (psi)

Bit Diameter: 3-3/4 inch
 Outer CT: 2.875" * 0.188" wall
 Inner CT: 1.75" * 0.134" wall
 Foam Quality Range: 0.5 to 0.96
 Min. cuttings velocity: 50 ft/min

I.D. = 2.499

I.D. = 1.482

Equivalent parasite string ID = $0.816 \cdot (d_2 - d_1) = 0.816 \cdot (2.499 - 1.75) = 0.6112"$

	A*	B*	C*	D	E	F	G	H*	I*	J
BH Fl. Vel (ft/min)	Motor Vol. Displac. (gal/rev)	Motor Mech. Eff. (~0.79)	Motor Hyd. Eff. (~0.88)	Motor Overall Eff. (Decimal)	Rotary Speed (rpm)	Motor Torque (ft-lbf)	Motor Power Output (hp)	Rock Spc. Energy (psi)	Bit Diameter (in)	Drilling Rate (ft/hr)
153	0.125	0.79	0.88	0.6952	211	303	12.17	100000	3.75	21.8
180	0.125	0.79	0.88	0.6952	211	303	12.17	100000	3.75	21.8
192	0.125	0.79	0.88	0.6952	282	303	16.22	100000	3.75	29.1
215	0.125	0.79	0.88	0.6952	282	303	16.22	100000	3.75	29.1
232	0.125	0.79	0.88	0.6952	352	303	20.28	100000	3.75	36.4
252	0.125	0.79	0.88	0.6952	352	303	20.28	100000	3.75	36.4

BH Fl. Vel (ft/min)	Motor Vol. Displac. (gal/rev)	Motor Mech. Eff. (~0.79)	Motor Hyd. Eff. (~0.88)	Motor Overall Eff. (Decimal)	Rotary Speed (rpm)	Motor Torque (ft-lbf)	Motor Power Output (hp)	Rock Spc. Energy (psi)	Bit Diameter (in)	Drilling Rate (ft/hr)
153	0.125	0.79	0.88	0.6952	211	605	24.33	100000	3.75	43.6
180	0.125	0.79	0.88	0.6952	211	605	24.33	100000	3.75	43.6
192	0.125	0.79	0.88	0.6952	282	605	32.45	100000	3.75	58.2
215	0.125	0.79	0.88	0.6952	282	605	32.45	100000	3.75	58.2
232	0.125	0.79	0.88	0.6952	352	605	40.56	100000	3.75	72.7
252	0.125	0.79	0.88	0.6952	352	605	40.56	100000	3.75	72.7

Note: * = Input data

$D = B \cdot C$ $E = C \cdot (GPM) / A$

$F = 3.064 \cdot A \cdot (DP) \cdot B$

$G = E \cdot F / 5252$

$J = 2.521 \cdot 10^6 \cdot G / I^{1/2} \cdot H$

DOE EXAMPLE FOAM WELL

Horizontal well: TVD = 3000 (ft), Hori. Disp. = 3000 (ft)

Normal surface gas injection.

Choke press. = 50 (psi)

Bit Diameter: 3-3/4 inch
 CT: 2.000" * 0.134" wall I.D. = 1.732"
 Foam Quality Range: 0.5 to 0.96
 Min. cuttings velocity: 50 ft/min

Liquid Rate (GPM)	Gas Inj. at BH (SCFM)	Pump/Comp. Press (psi)	Pipe P above mtr (psi)	Motor P. Drop (psi)	Motor Flow rate (gpm)	Motor Power In (hp)	Bit P. Drop (psi)	BH Press (psi)	BH ECD (ppg)	Surf. Foam Q. (-)	BH Foam Q. (-)	BH Ctgs. Vel (ft/min)	BH Fl. Vel (ft/min)
30	60	849	1953	1000	32	19	7.6	946	6.06	0.77	0.15	41	87
30	120	819	1812	1000	35	20	9.5	803	5.14	0.87	0.31	54	106
40	60	969	2043	1000	42	25	12.7	1030	6.6	0.71	0.11	65	110
40	120	903	1889	1000	45	26	15	874	5.6	0.83	0.23	78	127
50	60	1103	2120	1000	52	30	19.2	1101	7.06	0.67	0.08	89	133
50	120	1019	1965	1000	54	32	21.8	943	6.05	0.80	0.18	102	149

Liquid Rate (GPM)	Gas Inj. at BH (SCFM)	Pump/Comp. Press (psi)	Pipe P above mtr (psi)	Motor P. Drop (psi)	Motor Flow rate (gpm)	Motor Power In (hp)	Bit P. Drop (psi)	BH Press (psi)	BH ECD (ppg)	Surf. Foam Q. (-)	BH Foam Q. (-)	BH Ctgs. Vel (ft/min)	BH Fl. Vel (ft/min)
30	60	1799	2953	2000	32	37	7.6	946	6.06	0.77	0.15	41	87
30	120	1716	2812	2000	34	40	9.5	803	5.14	0.87	0.31	54	106
40	60	1937	3043	2000	42	49	12.7	1030	6.6	0.71	0.11	65	110
40	120	1832	2889	2000	43	50	15	874	5.6	0.83	0.23	78	127
50	60	2081	3120	2000	52	61	19.2	1101	7.06	0.67	0.08	89	133
50	120	1970	2965	2000	53	62	21.8	943	6.05	0.80	0.18	102	149

DOE EXAMPLE FOAM WELL

Horizontal well: TVD = 3000 (ft), Hori. Disp. = 3000 (ft)

Normal surface gas injection.

Choke press. = 50 (psi)

Bit Diameter: 3-3/4 inch
 CT: 2.000" * 0.134" wall I.D. = 1.732"
 Foam Quality Range: 0.5 to 0.96
 Min. cuttings velocity: 50 ft/min

	A*	B*	C*	D	E	F	G	H*	I*	J
BH Fl. Vel (ft/min)	Motor Vol. Displac. (gal/rev)	Motor Mech. Eff. (~0.79)	Motor Hyd. Eff. (~0.88)	Motor Overall Eff. (Decimal)	Rotary Speed (rpm)	Motor Torque (ft-lbf)	Motor Power Output (hp)	Rock Sp. Energy (psi)	Bit Diameter (in)	Drilling Rate (ft/hr)
87	0.125	0.79	0.88	0.6952	225	303	12.98	100000	3.75	23.3
106	0.125	0.79	0.88	0.6952	246	303	14.20	100000	3.75	25.4
110	0.125	0.79	0.88	0.6952	296	303	17.03	100000	3.75	30.5
127	0.125	0.79	0.88	0.6952	317	303	18.25	100000	3.75	32.7
133	0.125	0.79	0.88	0.6952	366	303	21.09	100000	3.75	37.8
149	0.125	0.79	0.88	0.6952	380	303	21.90	100000	3.75	39.3

BH Fl. Vel (ft/min)	Motor Vol. Displac. (gal/rev)	Motor Mech. Eff. (~0.79)	Motor Hyd. Eff. (~0.88)	Motor Overall Eff. (Decimal)	Rotary Speed (rpm)	Motor Torque (ft-lbf)	Motor Power Output (hp)	Rock Sp. Energy (psi)	Bit Diameter (in)	Drilling Rate (ft/hr)
87	0.125	0.79	0.88	0.6952	225	605	25.96	100000	3.75	46.5
106	0.125	0.79	0.88	0.6952	239	605	27.58	100000	3.75	49.4
110	0.125	0.79	0.88	0.6952	296	605	34.07	100000	3.75	61.1
127	0.125	0.79	0.88	0.6952	303	605	34.88	100000	3.75	62.5
133	0.125	0.79	0.88	0.6952	366	605	42.18	100000	3.75	75.6
149	0.125	0.79	0.88	0.6952	373	605	42.99	100000	3.75	77.1

Note:

* = Input data

$$D = B * C \quad E = C * (GPM) / A$$

$$F = 3.064 * A * (DP) * B$$

$$G = E * F / 5252$$

$$J = 2.521 * 10^6 * G / I^{1/2} / H$$

DOE EXAMPLE WATER WELL

Horizontal well: TVD = 3000 (ft), Hori. Disp. = 3000 (ft)

Water only injection.

Choke press. = 50 (psi)

Bit Diameter: 3-3/4 inch
 CT: 2.000" * 0.134" wall I.D. = 1.732"
 Foam Quality Range: 0.5 to 0.96
 Min. cuttings velocity: 50 ft/min

Liquid Rate (GPM)	Gas Inj. at BH (SCFM)	Pump Press (psi)	Pipe P above mtr (psi)	Motor P. Drop (psi)	Motor Flow rate (gpm)	Motor Power In (hp)	Bit P. Drop (psi)	BH Press (psi)	BH ECD (ppg)	Surf. Foam Q. (-)	BH Foam Q. (-)	BH Ctgs. Vel (ft/min)	BH Fl. Vel (ft/min)
30	N/A	1165	2379	1000	30	18	6.3	1373	8.8	0.00	0.00	32	73
40	N/A	1237	2391	1000	40	23	11.2	1380	8.84	0.00	0.00	57	98
50	N/A	1325	2407	1000	50	29	17.5	1389	8.91	0.00	0.00	81	122

Liquid Rate (GPM)	Gas Inj. at BH (SCFM)	Pump Press (psi)	Pipe P above mtr (psi)	Motor P. Drop (psi)	Motor Flow rate (gpm)	Motor Power In (hp)	Bit P. Drop (psi)	BH Press (psi)	BH ECD (ppg)	Surf. Foam Q. (-)	BH Foam Q. (-)	BH Ctgs. Vel (ft/min)	BH Fl. Vel (ft/min)
30	N/A	2165	3379	2000	30	35	6.3	1373	8.8	0.00	0.00	32	73
40	N/A	2237	3391	2000	40	47	11.2	1380	8.84	0.00	0.00	57	98
50	N/A	2325	3407	2000	50	58	17.5	1389	8.91	0.00	0.00	81	122

DOE EXAMPLE WATER WELL

Horizontal well: TVD = 3000 (ft), Hori. Disp. = 3000 (ft)

Water only Injection.

Choke press. = 50 (psi)

Bit Diameter: 3-3/4 inch
 CT: 2.000" * 0.134" wall I.D. = 1.732"
 Foam Quality Range: 0.5 to 0.96
 Min. cuttings velocity: 50 ft/min

	A*	B*	C*	D	E	F	G	H*	I*	J
BH Fl. Vel (ft/min)	Motor Vol. Displac. (gal/rev)	Motor Mech. Eff. (~0.79)	Motor Hyd. Eff. (~0.88)	Motor Overall Eff. (Decimal)	Rotary Speed (rpm)	Motor Torque (ft-lbf)	Motor Power Output (hp)	Rock Spc. Energy (psi)	Bit Diameter (in)	Drilling Rate (ft/hr)
73	0.125	0.79	0.88	0.6952	211	303	12.17	100000	3.75	21.8
98	0.125	0.79	0.88	0.6952	282	303	16.22	100000	3.75	29.1
122	0.125	0.79	0.88	0.6952	352	303	20.28	100000	3.75	36.4

BH Fl. Vel (ft/min)	Motor Vol. Displac. (gal/rev)	Motor Mech. Eff. (~0.79)	Motor Hyd. Eff. (~0.88)	Motor Overall Eff. (Decimal)	Rotary Speed (rpm)	Motor Torque (ft-lbf)	Motor Power Output (hp)	Rock Spc. Energy (psi)	Bit Diameter (in)	Drilling Rate (ft/hr)
73	0.125	0.79	0.88	0.6952	211	605	24.33	100000	3.75	43.6
98	0.125	0.79	0.88	0.6952	282	605	32.45	100000	3.75	58.2
122	0.125	0.79	0.88	0.6952	352	605	40.56	100000	3.75	72.7

Note:

* = Input data

$$D = B * C \quad E = C * (GPM) / A$$

$$F = 3.064 * A * (DP) * B$$

$$G = E * F / 5252$$

$$J = 2.521 * 10^6 * G / I^2 / H$$