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Maximizing Drilling Operations By Mitigating The Adverse Affects of Friction Through Advanced Drilling Fluid Technology

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Abstract

In the past decade, the drilling industry has made tremendous advancements in technology that have allowed the extension of drilling technical limits[1]. Everything from larger top drives, to rotary steerable tools to "smart" pipe, reaches and depths once thought of as unattainable are now commonplace due in part because of these technologies. With these extended limits come the problems with the inherent friction of these new limits. A new advanced environmentally safe drilling fluid (DFL) technology that is 100% compatible with most drilling fluid systems and mitigates the negative effects of surface and down hole friction has shown to substantially improve operational efficiencies, thus resulting in more efficient drilling operations and lower drilling costs. This alleviation of most of the inherent drilling friction has manifested as faster rates of penetration, lower surface and down hole torque, lower pick up and slack off drag, lower down hole vibrations, reduced stick-slip, reduced equipment and material wear, longer bit life, faster trips, lower drilling fluid losses and the promotion of wellbore stability in directional, horizontal and ERD wells.

Unlike conventional drilling fluid additives made for the use of friction mitigation, the DFL technology does not negatively alter the drilling fluid rheology, thus not requiring the addition of other drilling fluid chemical additions to bring the fluid properties back to their original state. The driving mechanism behind this technology is the alteration of the flowing conduit, rather than the properties of the drilling fluid. Couple this with the friction mitigation, and that the DFL technology stays in the system (has very little dissipation or does not get thrown out over the shakers), and maintains its efficacy over time, the time and cost savings implications can be substantial.

Introduction

Over seventy percent of all energy that is delivered by a drilling rig and its surface and down hole equipment to drill a well is lost through friction[2]. In the drilling of directional, high angle and extended reach wells, this energy loss can mean the difference effectively meeting the target objective, or not.

All too often, companies do not have the resources to purchase new or more powerful drilling equipment to overcome the negative effects of friction. This can lead to stopping short of the overall objective or not drilling the well and leaving untapped reserves behind. Friction reducers, or as there are commonly referred to in the drilling industry, "lubricants" can help in alleviating this friction. The three problems that are common with the use of standard lubricants are compatibility, efficacy and environmental compliance. Although this DFL technology meets all environmentally mandated discharge regulations throughout the world, both on land and offshore (i.e. LC-50, Microtox, etc.), this paper will focus on compatibility and efficacy.

Causes of Friction

Every well, whether vertical or directional, loses rig power through friction. This friction loss comes from the operating of standard mechanical surface equipment, through the down hole drilling tools-to-casing and down hole drilling tools-to-open hole contact and through the flowing of the drilling fluid in the drill string and wellbore. Operational efficiencies are tremendously hindered by only delivering a fraction of the energy that is placed into the well to drill, trip and complete.

Friction is the function of the reactive forces that are a result of two bodies rubbing against each other. This is the rubbing of wear components at the surface of the rig, the sliding and rotation of drill string components and casing against other casings or formation and the flowing of drilling fluid in the wellbore.

Surface friction is typically mitigated with the use of greases, oils and lubricants. These "lubes" ease the increase in friction that result as various surface equipment components churn to generate and transfer power to the drilling rig to drill and pump fluids. These lubes are typically in a non-diluted form and are applied directly to the component where the friction is being generated. The lower the friction, the more rig power can be transferred to the drill string and other drilling components to drill the well.

Down hole friction is polynomial where there are several drilling functions that can contribute to the increase in friction. The three main contributors (responsible for at least 95% of friction below the rotary table) are drilling torque, drilling drag and flowing pressure losses (i.e. equivalent circulating densities (ECDs)).

The drilling fluids that are used in the oil and gas industry are very complex and have various functions including cuttings transport, cooling and lubrication. Unlike closed systems such as engines and pumps, drilling fluid systems are not in a pressurized system and are subject to outside contaminants that are not seen in closed systems. Therefore the properties of the drilling fluids must be such that with the introduction of these contaminants (i.e. well bore fluids, drill cuttings, etc.), they do not adversely affect the primary functions of the drilling fluids.

Drilling Torque

Drilling Torque (angular friction) is generated when the drill bit, bottom hole assembly and the drill pipe are rotated while conducting drilling operations such as drilling ahead, rotating in the slips or back reaming. (Figure 1) During rotational drilling, drilling torque accounts for a majority of the energy lost through friction.

If left unmitigated, drilling torque can bring the drilling process to a halt. When drilling torque approaches or exceeds the rig's rotary (top drive or rotary table) capability, the drilling process becomes very limited or even ceases if left unmitigated. The ability to rotate is necessary to break the static friction that exists between the drill string-to-casing or drill string-to-formation.

The inability to rotate effectively manifests as slower drilling rates and poor hole cleaning, which can lead to even higher friction, lost circulation and stuck pipe. Also rotating the drill string continuously at the higher torque can lead to more frequent surface equipment failures, down hole equipment failures, casing wear and drill string failures.

Drilling Drag

Drilling Drag (axial friction) is generated as the drill bit, bottom hole assembly and drill pipe slide against the formation or casing while slide drilling, tripping or running casing. (Figure 2)

Excessive drag can "bog down" pipe trips in and out of the well bore as well as prevent casing from being run to bottom or its intended depth. When the reactive frictional forces from sliding friction near and exceed the weight of the running string, running of the pipe becomes difficult, slows down, stops as it begins to "weight stack". If pulling out of the well, this can lead to exceeding the pick up limitation of the drilling rig. The slower trips, whether in our out, result in more rig time, and thus more costs on a well.

While tripping into the well, as the friction forces increase, the pipe can start to buckle; first sinusoidally and then helically. In sinusoidal buckling, the pipe will still move, albeit sporadically. If the helical buckling point is reached, pipe movement into the well will stop and permanent pipe damage to the running string can occur. (Figures 3 & 4)

ECDs

ECDs (Equivalent Circulating Densities) are generated as the fluid flows in the annular area between the drill string and casings or drill string and formation. The friction that is created by the fluid flowing along the drill pipe, casings and formation create an equivalent hydrostatic pressure that the wellbore will experience that is higher than the static hydrostatic mud weight. When the ECDs get to high, they can potentially lead to fluid loss or formation break down due to exceeding formation fracture gradient.

ECDs are inherent, and there will always be an increase in pressure, even in the most ideal drilling fluids, as long as the fluid is flowing. The solids that are part of the composition of drilling fluids cause an increase in fluid rheologies, such as Plastic Viscosity (PV) and Yield Point (YP), amongst others, which in turn require more force to move the fluid up and/or along the wellbore. This increase in force is ECD. (Figure 5)

Mitigating Friction

There are numerous ways to mitigate friction. The drilling industry has employed several types of techniques, equipment and materials to try and lower friction. For drilling torque, drag and ECDs, many operators have chosen to merely change drilling parameters to reduce the amount of friction that is realized by drilling the well. The problems with this technique are that since most friction in a well is inherent in that it is a function of wellbore geometry, there is only so much of that friction that can be reduced. Although a driller may think that he is seeing some relief from the reduced parameters, (i.e. slower rotary speed, lighter weight-on-bit and slower pumping rates), the fact is friction will ultimately increase due to the increase in drill cuttings in the wellbore (poor hole cleaning) and result in slower drilling (lower ROP), higher drag and higher ECDs.

Some operators have used drill pipe rollers and low friction material drill pipe collars to help reduce friction. Although the industry has made strides in the development of these types of friction reducing types of equipment, there have been and there still is the chance that by adding another mechanical component in the drill string, down hole under the tremendous stresses and strains of high friction wells, that failure of that equipment will occur and at a minimum cause an expensive "fishing" job, or possibly junk the wellbore altogether.

Drilling beads have been utilizing in the industry for many years to try and reduce drilling torque and drag. If you ask ten different operators/contractors if the beads were successful in mitigating the friction, you will probably get ten different answers. Theoretically the beads act as ball-bearings beneath the drill string and allow the drill string to glide along the wellbore. In reality, the tremendous forces that are seen with the contact of the drill string to the formation or casing can literally crush the beads and not only not help in friction reduction, but also quite possibly cause formation damage, leave a large amount of crushed beads in the wellbore and be quite costly as they are discarded over the shakers at the surface. Although there are “bead recovery units” that are available to be used in conjunction with the bead application, the additional space required, added personnel to run the BRU and the added cost of the BRU can render the application operationally cumbersome and marginally economic.

The most straight forward approach, and which on the surface may appear to be the simplest approach in friction reduction, is the drilling fluid; either by thinning the fluid out or adding lubricants and other materials to reduce friction and thus free up that energy to optimize drilling operations. The problem is that they are neither straight forward nor simple, and misapplication of drilling fluid could lead to more widespread problems in the drilling of the wells.

The concept of adding a lubricant into a drilling fluid to “slick it up” is fairly easy to understand. By creating a layer of lubricant between the drill pipe, casing and formation, this should enable the friction to be reduced. And if the problem is ECDs, then by thinning out the fluid[3], the ECDs should decrease as there is less energy required to move the drilling fluid.

So this is where it gets more complicated in that since most lubricants are “flowing lubricants” and merely oils, when added to the drilling fluid they alter the drilling fluid properties. They get their efficacy by changing the drilling fluid’s properties and thus how the fluid flows. If applied too liberally, the oil concentration can change the fluid properties to where the primary function of the drilling fluid is altered and thus it is required to make expensive chemical additions to the drilling fluid to maintain the fluid rheologies within the prescribed specifications. If applied to liberally, the lubricant can thin out the drilling fluid and thus reduce its carrying capacity or gel strength. This could lead to cuttings fall out and barite sag and thus possibly stuck pipe. If not applied in an adequate concentration, then the lubricant may not work at all and then that is an unnecessary added expense.

DFL Technology

A tremendous amount of research and development has been conducted in developing a drilling fluid lubricant (DFL) technology that would have extremely high contact friction reductions and reduce ECDs all while maintaining drilling fluid properties and maintaining environmental compliance. By attaining these goals, not only can the fluid be utilized in the most demanding environments, but also allow for the optimization of drilling operations thus resulting in reduced overall drilling costs.

Laboratory tests and field applications have shown that this fluid technology not only yields higher friction reductions, but also maintains drilling fluid properties within the fluid’s original designed functions, and also reduces ECDs, wear and helps promote wellbore stability. All tolled, and when applied as prescribed, overall drilling operations can be optimized.

What makes this fluid technology different than typical lubricants is that it is a bonding lubricant rather than a flowing lubricant. Instead of altering the properties of the drilling fluid, it alters the flow boundary in which the drilling fluid flows by bonding to the surface of the drill pipe, casing and formation. By creating a bond with the surface, the eddy currents that are inherent in the flow boundary of the conduit are mitigated and thus reduce the effects of friction pressure. Couple this with the strong monolayer bonding and the lubricity characteristics of the lubricant, the metal-to-metal and metal-to-formation friction are mitigated thus yielding lower ECDs, lower torque and lower drag as well as reduced wear, lower vibrations and reduced stick-slip. (Figure 6)

Laboratory Testing

The DFL technology was tested on several types of friction measuring apparatus and with several different types of drilling fluids to determine its friction reducing capability.

The DFL technology was tested for friction reductions at concentrations ranging from 2% to 6% v/v in varying mud weights and types. (Table 1) Although showing varying degrees of friction reduction, this fluid technology consistently showed higher reductions in friction than are typical for the industry. Compatibility tests of these treated drilling fluids yielded no detrimental affects to the drilling fluid properties with these concentrations of the DFL technology. (Table 2)

In addition to contact friction testing, a fluid loop was constructed to determine the effects of the DFL technology on ECDs. (Figure 7) Testing of both water based and oil based drilling fluids, at concentrations as low as 1% indicated a reduction if flowing friction pressure (ECDs) as high as 79%. (Table 3) For example, on a well where the static mud weight is 10.2 ppg and the ECD is 11.8 ppg, a reduction in ECD by 65% would yield an ECD with the treated drilling fluid of 10.76 ppg or a reduction of 1.04 ppg. In a well where the fracture gradient in the wellbore is questionable or low, this type of reduction could be the difference between losing fluid or breaking down the formation and successfully drilling the well.

Field Applications

Field applications of the DFL technology have yielded promising results. The mitigation of friction on these applications have shown that by reducing friction, drilling operations can be optimized thus potentially resulting in lower drilling costs.

The wells were high angle and horizontal wells, where friction can consume over 70% of all energy put into the well. On a well (Figure 8) on which a window was milled and approximately 75% of the wellbore was cased off, the application of 1% of the DFL technology into the drilling fluid resulted in an increase in the sliding rate of penetration of 333%, from 15 fph to over 50 fph. The pick up weights were decreased from 320Klbs to 275Klbs, or a 14% reduction.

Slack off weights were increased from 185Klbs to 220Klbs, or 16%. Stand pipe pressures were decreased from 2,460 psi to 1700 psi or 30%. (Table 4)

On several horizontal wells where the DFL technology was applied, (Figure 9) the operators saw decreases in torque ranging from 25% to 40%, surface weight-on-bit to down hole weight-on-bit transfers to less than 5,000 lbs and rate of penetration increases from 50% to 150%. Additionally the operators saw the wellbores become more stable in that prior to utilizing the DFL technology multi-day reamer runs were required to condition the wellbores for the subsequent casing runs, to eliminating the need for reaming altogether after utilizing the DFL technology. (Table 5)

An additional benefit that has been realized is that since some operators are choosing to reuse their drilling fluids from well- to-well, and since the DFL technology maintains its full efficacy over time, they have been able to reduce their overall "lubricant" applications by one-half or two-thirds. By transferring the DFL technology treated drilling fluid from well-to-well and regulating their lubricant additions to only new hole maintenance on subsequent wells, the overall cost to apply this technology has been less than other standard industry lubricants that do not have this efficacy benefit.

Conclusions

All tolled, the testing and applications of the DFL technology appears to have the ability to mitigate friction in drilling fluids without detrimentally altering the drilling fluids properties. The types of performance improvements seen in the field could maximize drilling operations by allowing the operators and contractors to optimize drilling parameters by mitigating friction. This improved performance could result in faster drilling, lower NPT and ultimately lower well costs. With the DFL technology maintaining its efficacy over time, this drilling fluid technology could reduce overall lubricant costs on multi-well drilling programs.

Acknowledgments

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Nomenclature

Define symbols used in the text here unless they are explained in the body of the text. Use units where appropriate.

BHA = *Bottom hole assembly*
ROP = *Rate of Penetration (fph)*
PU = *Pick Up (lbs)*
SO = *Slack Off (lbs)*
ECD = *Equivalent Circulating Density (ppg)*
SPP = *Stand Pipe Pressure (psi)*
GPM = *Gallons Per Minute (gpm)*
BRU = *Bead Recovery Unit*
NPT = *Non-Productive Time (hours)*
DFL = *Drilling Fluid Lubricant*
FPH = *Feet Per Hour*

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Figure 1 - Rotational Friction (Drilling Torque)

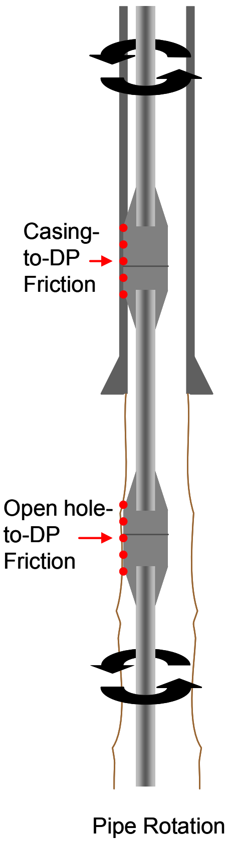

Figure 2 - Axial Friction (Sliding Drag)

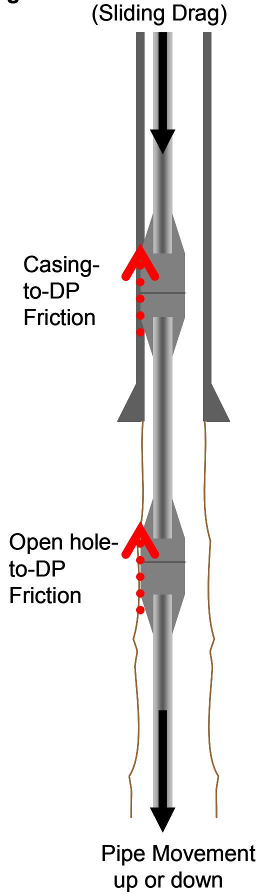

Figure 3 - Sinusoidal Buckling

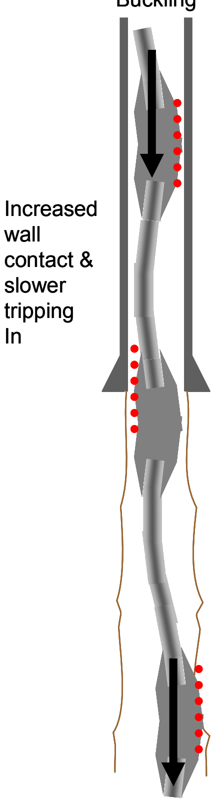

Figure 4 - Helical Buckling

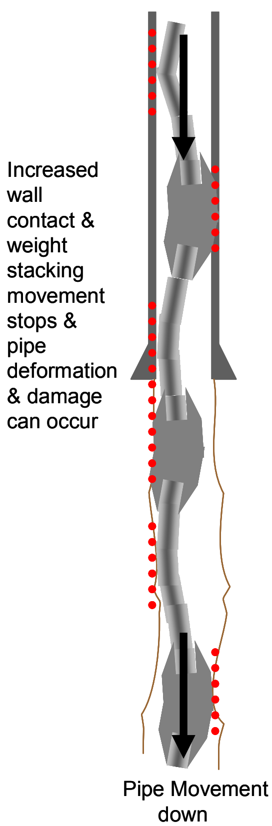

Figure 5 - Equivalent Circulating Density

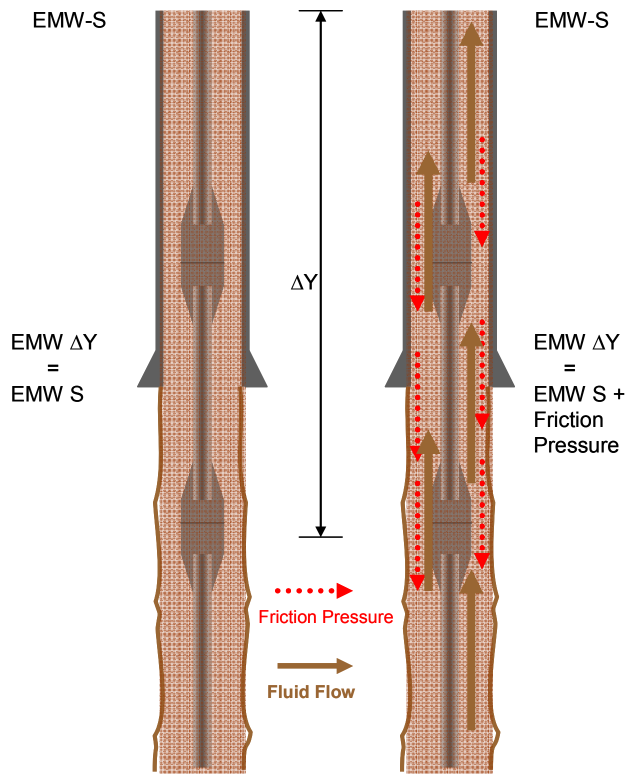

Table 1 - Laboratory Testing: Percent Coefficient of Friction Reduction

		OBM/SBM				WBM		
		Concentration % v/v				Concentration % v/v		
Testing Device	MW-ppg	3	4	6	MW-ppg	3	4	6
Baroid Lubricity Meter	11.2	78 %	82 %	85 %	12.5	82 %	87 %	87 %
Falex Pin & Vee Block	11.4	26 %	28 %	36 %	10.5	54 %	57 %	62 %
Lubricity Evaluation Monitor	12.2	48 %	50 %	57 %	11.5	56 %	60 %	64 %
OFITE Lubricity Tester	10.9	39 %	43 %	52 %	9.8	67 %	75 %	77 %

Table 2 - Fluid Compatibility Tests

11.5 ppg WBM

	Base	4% DFL	6% DFL
600	138	142	143
300	94	96	97
200	72	75	76
100	49	52	53
6	18	19	21
3	13	14	16
PV	44	46	46
YP	50	53	54
10s/10m	16/36	18/38	19/40
API FL	5.2 cc	4.0 cc	4.0 cc

11.2 ppg 85:15 SBM

	Base	4% DFL	6% DFL
600	200	189	174
300	125	120	111
200	96	90	84
100	72	64	59
6	26	24	21
3	22	20	18
PV	75	69	63
YP	50	51	48
10s/10m	26/33	25/31	22/28
API FL	7.6 cc	7.0 cc	6.8 cc

Figure 7 - ECD Flow Loop Testing Appratus

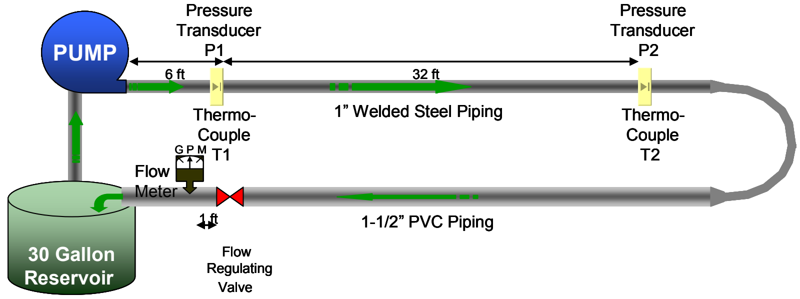

Table 3 - ECD Flow Loop Tests Results

Test #	% DFL	Avg. Temp (C)	Flow rate (gpm)	Pressure drop (psi)	Comments
1	0.00	33.54	8.00	5.34	10.4 ppg WBM baseline test
2	0.00	33.33	8.00	5.00	11.2 ppg OBM baseline test
3	1.00	33.68	8.00	1.68	10.4 ppg WBM - 68% drop
4	1.00	34.23	8.00	2.24	11.2 ppg OBM - 55.2% drop
5	4.00	32.57	8.00	1.32	10.4 ppg WBM – 75% drop
6	4.00	34.43	8.00	2.18	11.2 ppg OBM – 56.4% drop
7	6.00	32.77	8.00	1.11	10.4 ppg WBM – 79% drop
8	6.00	33.83	8.00	2.02	11.2 ppg OBM – 59.6% drop

8 gpm in 1" pipe is equivalent to 500 gpm in an 8 ½" hole with 5" drill pipe.

Figure 6 - Bonding Lubricant Flow Boundary Effect

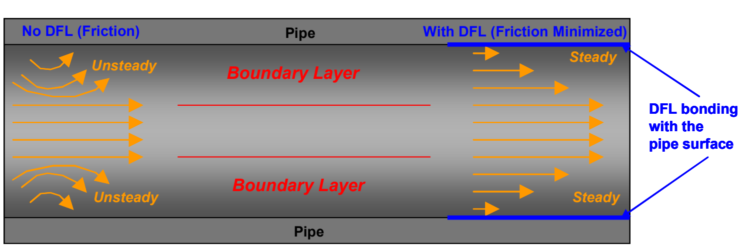

Figure 8 - Field Application: Slide Drilling Friction Reduction

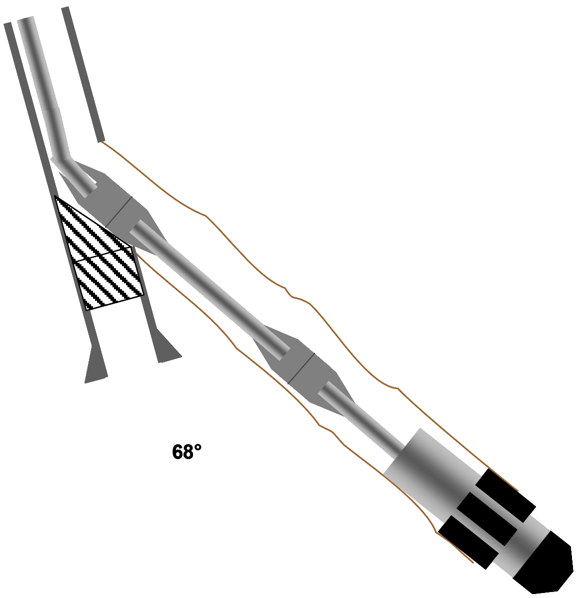

Figure 9 - Field Application: Horizontal Rotary Drilling Friction Reduction

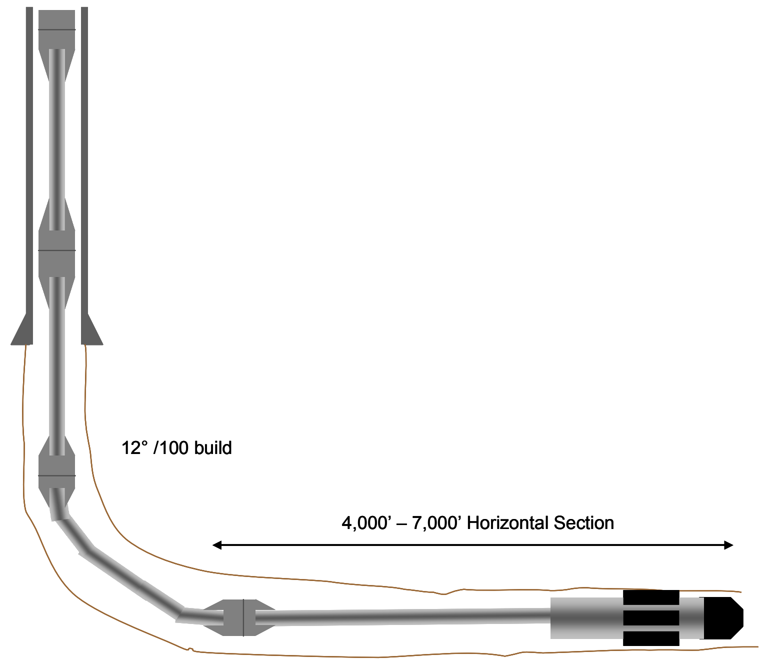

Table 4 - Field Application: Slide Drilling Mode Drilling Improvement

% Additive	RPM	SWOB	Flow Rate	Drlg Torque	PU Torque	PU	SO	ECD	SPP on Btm	SPP off btm	ROP
		1000 lbs	gpm	1000 ft lbs	1000 ft lbs				psi	psi	ft/hr
0	0	5	500	22	24	320	185		2460		6.25
0	0	5	550	23	24	322	185		2440	1250	8.66
0	80	10	580	22	23	322	187		2460	1400	15.2
0	80	10	580	22	23	318	185		2460	1400	15
0.5	80	10	580	19	18	308	190		2220	1400	18.27
0.5	80	10	580	18	16	301	190		2200	1400	22.64
1	80	10	580	16	15	285	201		1800	1400	55.07
1	80	10	580	15	13	275	215		1770	1400	54.02
1	40	10	580	15	15	275	220		1700	1500	56.89
1	80	10	580	16	14	277	222		1700	1500	55.2
1	80	10	580	15	14	275	220		1700	1500	54.32

Table 5 - Field Applications: Horizontal Well Drilling Improvement

Well	ROP Before	ROP After	Torque Before	Torque After	SPP/ECD Before	SPP/ECD After	PUW Before	PUW After	Surf-DH WOB Diff
1	17	73	18500	14500	2200	1750	150k	139k	-5k
2	22	105	22500	16200	2440	2000	167k	144k	-3k
3	15	63	24000	18300	2250	1677	177k	151k	-5k
4	24	68	24500	17700	2333	1800	188k	163k	-4k
5	18	82	20500	13800	2400	2110	162k	142k	-7k

Well lengths ranged form 12,500 feet to 15,200 feet. Horizontal section lengths ranged from 3,000 feet to 6,000 feet. WBM mud weight ranges were from 9.0 ppg to 11.2 ppg. All applications of the DFL were at 3% v/v to the system.