AADE 01-NC-HO-33

Improving Total Well Construction Efficiency by Addressing Wellbore Quality

Blaine C. Comeaux, Sperry-Sun Drilling Services, a Halliburton Company
AADE Member

Abstract

Wellbore quality is generally related to the "smoothness" of the wellbore, or the "tortuosity". It is commonly believed that the primary contributor to tortuosity is excessive local doglegs; but, as demonstrated in a previous paper,[1] a more important contributor to total tortuosity is wellbore spiraling. It has been observed that almost every well contains some degree of spiraling unless specific measures are taken to prevent it. While the industry has come to think of spiraling as a logging tool response problem, a spiraled wellbore has a significant impact on drilling efficiency and cost. This paper will discuss several case studies in the Gulf of Mexico that demonstrate the considerable economic impact of producing a smooth, high-quality, unspiraled wellbore.

Introduction

The quality of the borehole produced when drilling oil and gas wells can have a dramatic impact on the total well construction time and cost and sometimes can even determine success or failure. The borehole quality becomes a more important issue in horizontal well and extended-reach well operations. Until the recent introduction of rotary steerable systems, very little technology has emerged to specifically improve the quality of the wellbore. In the absence of any specific technology, there is little recognition of the potential benefits that might be achieved should some method be available for drilling a "truer" wellbore, one that followed a straighter line or smoother arc with minimal deviation.

Most drilling engineers appreciate the need to stay close to the planned well trajectory and avoid any excessive local doglegs. However, once these goals are achieved and the well reaches total depth, there is very little pressure on the directional drilling service company to achieve a "better" wellbore next time (although there is almost always pressure to drill it faster). For projects where torque and drag are obvious concerns, the well plan is more closely scrutinized. Multiple plan options are generated, and the lowest torque-producing plan that achieves the target without an excessive amount of directional steering time gets selected. From the technology side, the first line of attack for a challenging well profile is usually synthetic-based or oil-based mud and/or lubricating beads for lubricity, rotary torque-reducing subs, adjustable gauge stabilizers, and ultimately rotary steerable technology. The directional driller must maintain a tighter tolerance on the well trajectory. But the measurements of the wellbore quality are usually 90-100 feet apart, a separation that greatly masks the true wellbore path. Because no convenient and accurate method is available to improve on this coarse measurement, it is accepted. As long as casing gets to bottom, the drilling is deemed successful.

Why Spiraling Occurs

Numerous borehole problems are encountered in drilling wells that can result in less than efficient drilling operations. Increasing rig rates and rig shortages put more pressure on the drilling engineer to find new ways to improve the process, avoid problems, and save money. While some problems are a function of wellbore stability, and must be addressed with proper mud weight, other issues arise as a result of poor wellbore geometry, the smoothness or "true"-ness , i.e., how well a borehole "follows itself" and stays on a straight line or a smooth arc.

One area that has been — for the most part — overlooked is borehole spiraling. Spiraling occurs when the center of the bit follows a more or less helical path around the true centerline of the planned well trajectory. The immediate question comes up: Is spiraling that prevalent; and if it is, why haven't we known it?

Two pieces of data would indicate that spiraling is prevalent in many wells. One is a study[1] that showed that wells drilled with a new, matched drilling system (see Figure 1) produced friction factors significantly lower than conventional steerable systems. In some cases, the friction factors in open hole and in casing were the same. The author is not aware of any wells ever drilled that have achieved friction factors as low as these are. This new, matched drilling system employs long gauge bits and specially modified extended power-section mud motors with pin-down connections. This system is run according to proprietary methods to insure consistent results over many wells. Since these low friction factors are unique to the wells drilled using this system, this would seem to imply that most wells are spiraled to some degree.

The other indication that wells are spiraled in general is the design of the tools used to drill them: long slender rods with bits on the end. By simple analogy, if we attempted to design a traditional drill bit used for drilling wood or metal and fashioned it after an oilfield bit, it would have the equivalent of half the diameter or less in gauge protection, immediately stepping back to a shank that was only, say, 2/3 the diameter of the bit.

The casual observer would not put great faith in this configuration to drill a very straight hole, especially if the shank were ten feet long and contained a bend four inches from the bit like a steerable motor. In fact, this “assembly” could be expected to wander off center until the “collar” or shank hit the side of the hole. The shank would continue to limit the bit’s maximum displacement from true center, “walking” around the borehole wall. The bit would continue to drill at maximum displacement from true center due to side forces, and would roll in the direction of rotation, thus generating a spiraled hole.

By comparison, a standard drill bit made for drilling wood or metal has several multiples of the diameter worth of “gauge protection”, also known as “fluting”. For example, a ½” bit has roughly 3-4 inches of “full gauge” fluting. The purpose of fluting on the sides of the standard wood or metal drill bit is not to achieve a gauge hole. It is there to insure a straight hole.

The analogy above represents two extremes, whereas reality is somewhere in between. Today’s directional assemblies generally have some stabilization that would tend to keep the bit closer to center, although the stabilization can be several feet behind the bit. Steerable motors do have a bent housing that creates a greater offset from center deliberately, thus increasing the side forces. There is also play in the driveshaft of a PDM motor, which also affords some lateral freedom.

In the end, the result is a rotating assembly with a built-in propensity to stray off-center. The magnitude of the problem is determined by the actual BHA configuration. This was recognized in the 1950’s, when Woods and Lubinski formulated an equation that came to be known as the “Crooked Hole Country” formula[3]. The formula was borne out of the observation that a tubular the same diameter as the bit could not be successfully inserted into a well after it had been drilled. In fact, the formula gave the maximum diameter tubular that should be attempted, given the bit diameter and collar diameter. Woods and Lubinski understood that the bit would wander off center and that the collar would limit the bit travel. The formula is

$$\text{Drift Diameter} = \frac{OD_{Bit} + OD_{Collar}}{2} \qquad (1)$$

In practice, the Woods-Lubinski formula means that, in a hole drilled with a 12-1/4 in. bit and 8 in. drill collars, the largest diameter tubular that should be attempted to be run in this well would be 10-1/4 in.

One way to prevent the bit from moving off center is to make the drill collars and the bit the same diameter, but this solution has immediate and drastic ramifications. A more realistic option would be to drill with a fully packed BHA. This option proved successful to some degree in drilling vertical wells, but obviously, this choice is severely limiting from a directional drilling standpoint. Another alternative is to put the stabilization immediately on the bit so that it is self-constraining. This solution is the fundamental approach we began with – a long gauge bit.

Long gauge bits have been around for years, and their propensity for drilling smooth wellbores is well known. However, the long gauge bit was not felt to be a tool that lent itself to directional drilling until some modifications were made to the steerable motor to overcome the challenge presented by the extra gauge. Controlled testing[2] demonstrated that, when combined with a specially designed mud motor and with some proprietary directional principles applied, these bits could be steered and could yield build rates equivalent to traditional shorter gauge bits.

Practical Benefits from Improved Hole Quality

Recently a new steerable system was introduced.[2] One of the goals of the system was to achieve very high quality wellbores. The results from using this new system have proven to have broad implications on the entire well construction process.

Improvements in borehole quality can dramatically affect the economics for an entire field development by increasing the potential reach from an existing fixed structure. For example, tapping into bypassed reserves on the flanks of structures can breathe new life into a field, allowing the continuing operation of the field utilizing fully depreciated surface production equipment and eliminating the need for new structures. Many isolated pockets can be connected with complex well geometries that would have been considered possible only with rotary steerable technology. And every well with any degree of difficulty will likely be drilled more efficiently by increasing the percentage of time spent on bottom — drilling — and by reducing "trouble time" associated with hole cleaning, backreaming, wiper trips, trips for failures, and general slow drilling due to bit damage.

In theory, some of the drilling metrics that should be impacted by a straighter wellbore include:

1. Bit Life – This should be especially noticeable on PDC bits, which are prone to impact damage. By constraining the bit to the center of the hole, impacts will be reduced. Longer bit life means fewer trips, a major potential for rig time savings.

2. Faster drilling – The fact that the bit is constrained and will therefore suffer less damage means that the bit is drilling at optimum performance for a greater part of the hole interval, thus leading to a higher average ROP. In areas of soft sediment where ROP is constrained due to hole cleaning, the total daily footage should be increased because less time is spent for hole cleaning. All the benefits listed below contribute to higher overall drilling efficiency.

3. Sliding ROP – It is a generally accepted truism that sliding ROP is always less than rotating ROP. The primary reason for this reduction is additional friction when sliding. In a spiraled hole, stabilizer blades and tool joints drag on a continuous series of troughs. Drag reduces the effective weight transfer and causes the weight-on-bit to fluctuate, thereby making toolface control more difficult. By eliminating this extra drag component, the weight transfer and hence ROP should increase.

   The other common difficulty with directional drilling is toolface control. With the bit centered and with more consistent weight transfer, toolface control should also improve. *In fact, in one study in the Gulf of Mexico, the average ROP in the oriented mode was increased from 24 ft/hr to 46 ft/hr, a 92% increase.*

4. Hole Cleaning – Log examples from spiraled holes show a pitch to the spiral of approximately 4-10 feet. This series of troughs act to slow down and trap cuttings. This problem is magnified as inclination increases and as the amount of open hole increases. The end result is extra time to circulate bottoms-up and a higher frequency of short trips, with a potential for a cuttings avalanche situation leading to a stuck BHA. Removing or greatly reducing these troughs should improve hole cleaning efficiency dramatically.

5. Torque and Drag – pickup and slackoff hookload and torque should be noticeably less than conventional systems if the hole is in fact straighter. A straighter hole would make for more trouble-free casing installations, fewer stuck pipe incidents, and more successful logging runs. All these benefits should reduce trouble time significantly. If torque and drag can be reduced enough, then this new system could replace rotary steerable technology in some instances, for both extended reach applications and difficult 3-D well plans.

6. Reliability – By placing additional gauge length on the bit, the bit is much more tightly restrained from lateral movement. By arresting the vibration initiation mechanism at the source, the entire BHA should experience a drop in vibration level and, subsequently, improved reliability for MWD/LWD components and mud motors.

7. Better logging tool response – A spiraled borehole can dramatically affect the response of a logging tool, especially tools with shallow depths of investigation like density and neutron porosity tools. The logging tool will straddle the peaks in the spiral on the low side, and so will remain relatively straight, while the borehole walls spiral around it. This continuously changing borehole effect produces an ambiguous "wiggle" to the log curves and can obscure the true measurement value. This concern is especially problematic in thin beds, where the true formation readings would already be changing continuously every few inches or feet.

8. Improved Cement jobs – If one could look down the spiraled hole, it would look like the inside of a pipe, with an internal thread, or look like a rifled gun barrel. If a straight tubular-like casing is run into a spiraled hole, the cross sectional diameter in the annulus will not be uniform due to the casing riding in the true center of the hole and the hole wandering along a helical path. The point of minimum clearance would be the top of the "thread", and it would be in continuous near-contact with the casing. Once cement is pumped into this annular space, this path of minimum clearance becomes a continuous bead of very thin cement sheath. The result may well be a continuous migration path from shoe to shoe.

Applications in Gulf of Mexico

In order to prove the merits of drilling a straighter borehole with little to no spiraling, a new drilling system has been introduced. This new drilling system, known as the SlickBore™ system, consists of a special long gauge PDC bit coupled to a specially modified extended-power section mud motor with a pin-down connection. The main modification to the motor involved reducing the bit-to-bend distance by shortening the bearing section. Proprietary modeling techniques are applied when designing the BHA to be run with the system. A patent is pending on the system and method. See Figure 1.

The matched system has been run over 250 times, in both soft and hard formations, offshore and on land, in water-based, oil-based, and synthetic muds, in locations around the world over the past three years. The system has shown a very consistent trend in its ability to drill faster in the sliding mode and to reduce the amount of circulating time and short trips required. In fields that have been drilled for years, the system has produced some of the fastest intervals on record. In other areas where drilling speeds were already thought to be maximized, the system has produced trouble-free wells with incredibly low torque and drag values, excellent logging tool readings, and consistently successful cement jobs.

Comparing the results of over 250 runs with approximately 1500 conventional wells in a global database shows that the SlickBore system drilling time breakdown is as follows:

	SlickBore	Conventional
On Bottom Drilling	62%	42%
Circulating/Reaming	9%	29%
Other	29%	29%

This information clearly indicates that, on average, the SlickBore system results in more time on bottom drilling and less time circulating.

More recently, this system has been run in the Gulf of Mexico on numerous occasions. A study was conducted on nine particular wells drilled in the Gulf of Mexico in three fields: Ship Shoal, South Timbalier, and West Cameron. The performance of the new system was compared to other mud motor runs in these areas using the same size motors with extended power sections but without the long gauge bit. Table 1 shows the summary of the results. Table 2 is a more comprehensive comparison of the data and the averages for the nine SlickBore™ System wells against similar values for twelve offset wells.

The results are stunning. The new system drastically improved the entire drilling operation from ROP to better bit life to reducing the time spent circulating for hole cleaning. Note that while the percent of time spent circulating was similar, the footage drilled was much greater. It is more meaningful to compare circulating hours per 1,000 feet, which was reduced 11%. These wells routinely run casing to bottom with minimal drag. Several of these projects ran hole openers after the drilled intervals as standard practice, but never encountered any real resistance.

Figure 2 shows the well plan for one typical well drilled with synthetic based mud. The results from this project were as follows:

- The torque values recorded on the rig were analyzed after this very difficult wellbore was drilled. The casing friction factor was assumed to be 0.15. Table 3 shows the resulting friction factor values calculated from the actual field results. The resulting average open hole friction factor was 0.147. This is 26% less than the typical value of 0.20 for an open hole friction factor with synthetic mud.

- The entire open hole interval of 11,127 feet was drilled without a single wiper trip. Assuming a typical wiper trip time of 5 hours, this resulted in perhaps 15-20 hours or more of rig time savings (about $50,000 to $75,000). While wiper trips can provide information about hole condition, it may be possible to extend the interval between them and save valuable rig time.

- Caliper logs indicated an incredibly smooth, gauge hole for the entire interval drilled with the new system. General log data quality was excellent.

- On the series of wells drilled on this particular project with the new system, no cement squeezes have ever been required (100% success). This success rate compares with an overall field success rate of about 98% and a general Gulf of Mexico success rate of about 90-95%. Cement bond logs indicate excellent cement distribution in the annulus. The time savings associated with eliminating a single squeeze operation on this rig is approximately 6 hours, for a savings of approximately $23,000.

Another case study involved a deepwater drill ship where the well was being sidetracked. Severe shock levels had been detected by an LWD tool just prior to a BHA failure. The sidetrack had to be repeated when the BHA was lost. A standard PDC bit was only able to generate an average ROP of 50 ft/hr. A rock bit in the same zone only managed 30 ft/hr. The new drilling system dramatically reduced the vibration levels and produced ROP's in the 150-200 ft/hr range. The repeat drilling of the sidetrack took about 2.5 days compares to 12 days for the standard assemblies. This scenario took place on a deepwater drillship where the rig costs exceeded $300,000/day. Thus, a conservative estimate of the savings is on the order of $3 million.

In another field application in the Viosca Knoll area, the vertical portion of the well was drilled using the new matched drilling system. Viosca Knoll is known for its drilling harshness, and multiple MWD/LWD tool failures due to excessive vibration are commonplace. The matched drilling system drilled the entire interval without a trip or any failures. The ROP was almost twice as fast as any other bit had ever generated in this block.

Conclusions

1. Friction factor values from wells drilled with a new drilling system are lower than those from wells drilled with traditional bits and motors. This observation implies that borehole spiraling exists to some degree in virtually all wells drilled with these traditional bits and motors.

2. Borehole spiraling can have a significant impact on drilling efficiency. Improvements in bit life, reduced circulating times, higher sliding rates of penetration, reductions in torque and drag, trouble-free casing and logging running operations, cement job success rates, and in reliability improvements in vibration-prone areas — all demonstrate this impact.

3. Improvements in borehole quality produce higher quality logging data, thereby improving the ability of the oil and gas company to make good decisions with regard to the final completion program. Such decisions can impact the entire production potential for a field.

4. Improvements in borehole quality can extend the lateral reach of conventional technology and allow complex 3-D well plans to tap into multiple marginal pockets of production.

Acknowledgements

The author would like to thank Sperry-Sun Drilling Services and Halliburton Energy Services for permission to publish the paper. Special thanks go to Tom Gaynor, David Chen, and Jeff Chappell for their case history support and review of the paper.

Nomenclature

BHA = *bottomhole assembly*
OD = *outside diameter*
LWD = *logging while drilling*
MWD = *measurement while drilling*
PDM = *positive displacement motor*
ROP = *drilling rate of penetration*
TD = *total depth*
TVD = *true vertical depth*

References

1. Gaynor, T., Chen, D. C-K., Stuart, D., and Comeaux, B. "Tortuosity versus Micro-Tortuosity – Why Little Things Mean a Lot," SPE/IADC Paper No. 67818, presented at the 2001 SPE/IADC Drilling Conference, Amsterdam, The Netherlands, 27 February -1 March.
2. Gaynor, T.M., Chen, D. C-K., Maranuk, C., and Pruitt, J. "An Improved Steerable System: Working Principles, Modeling, and Testing", SPE Paper No. 63248, presented at the 2000 SPE Annual Technical Conference and Exhibition, Dallas, Texas, 1-4 October.
3. Woods, H.B. and Lubinski, A. "How to Determine Best Hole and Drill Collar Size", The Oil and Gas Journal, June 7, 1954

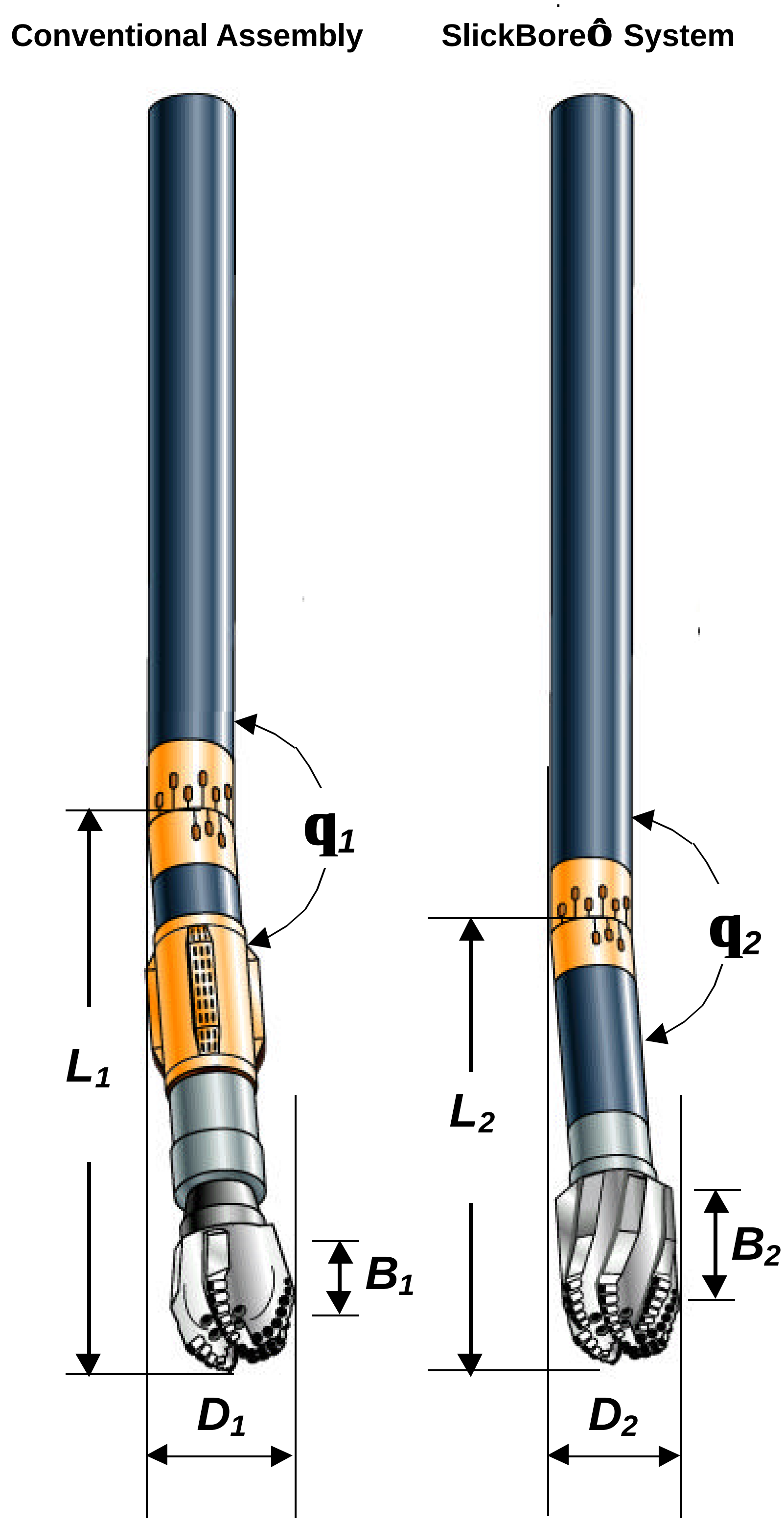

Figure 1 – The SlickBore System consists of a long gauge box-up bit combined with a pin-down mud motor with a newly designed bearing section to reduce the bit-to-bend distance. This relationship was critical in order to achieve the build rates necessary to make the long gauge bit an effective tool in the directional driller's arsenal. Because the bit-to-bend distance is less ($L_2 < L_1$), the angle setting (θ_2) on the motor is usually reduced as well, thus achieving build rates similar to a standard motor with a higher setting.

Table 1 – Summary of Comparison between SlickBore and Conventional Performance Motor Assemblies in GOM

Well	Average Footage Drilled (ft)	Circulating Hours per 1000 Feet	Dull Bit Grades After 3 wells over 26,000 ft	Average WOB (lbs)	Sliding ROP (ft/hr)	Rotating ROP (ft/hr)
Conventional Motors	4419	2.26	Requires 3 bits	6467	24	72
SlickBore System	8168	2.02	2-1-WT-A-I-NO	3988	46	93
% Improved	**84%**	**11%**	**300%**	**39%**	**92%**	**29%**
Comments		In some cases, only 6 hours of circulation is required for 100 hours of drilling				The ratio of sliding ROP to rotating ROP was increased from 1/3 to 1/2

SLICKBORE System vs. STANDARD BHA COMPARISON

	SLICKBORE	**STANDARD**	**SLICKBORE DIFFERENCE**
DRILLING DATA			
Unique Wells	**9 Wells**	**12 Wells**	
Total Runs	15 Runs, **1.6 Runs**/Well	33 Runs, **2.7Runs**/Well	**1.1 Fewer Runs (Fewer Trips)**
Drilling Hours	903 Hrs, **60 Hrs**/Run	941Hrs, **28 Hrs**/Run	**32 More Drilling Hours per Run**
Rotating Hours	655 Hrs, **44 Hrs**/Run	614 Hrs, **19 Hrs**/Run	**25 More Rotating Hours per Run**
Circulating Hours	248 Hrs. **16.5 Hrs**/Run	327Hrs, **10 Hrs**/Run	**6.5 More Circulating Hours per Run**
Reaming Hours	36Hrs, **2.4 Hrs**/Run	44 Hrs, **1.3 Hrs**/Well	**1.1 More Reaming Hours per Well**
Below Rotary Hours	1597 Hrs, **106 Hrs**/Run	2158 Hrs, **65 Hrs**/Run	**41 More Hrs Below Rotary per Well**
Distance Oriented	10729 Ft , **1192Ft** /Well	7745 Ft, **645 Ft**/Well	**547 More Ft Oriented per Well**
Distance Rotated	62781Ft, **6976 Ft** /Well	44213 Ft, **3684 Ft**/Well	**3292 More Ft Rotated per Well**
Total MD Interval	73510Ft, **8168 Ft** /Well	53025 Ft, **4419 Ft**/Well	**3749' More per Well (In the same drilling hours**
Total TVD Interval	59642Ft, **6627 Ft** /Well	38073 Ft, **3173 Ft**/Well	**3454' More TVD (Deeper, more complex wells)**
AVERAGES			
Drilling Hours/ Well	**104**	104	**3749' More per Well (In the same drilling hours)**
Orienting Hours/ Well	**27**	29	**547' More per Well (In 10% less orienting hours)**
Rotating Hours/ Well	**77**	75	**3 % More Rotating Hours per Well**
Circulating Hours/ Well	**28**	28	**3749' MD. More per Well**
Circulating Hours/Foot	**0.00202**	0.00226	**11% Reduction in Circulating Hours per Foot drilled**
Reaming Hours/ Well	**4**	4	
ROP Oriented	**46**	24	**92% Faster Orienting ROP**
ROP Rotated	**93**	72	**29% Faster Rotating ROP**
ROP Average	**82**	56	**46% Faster Average ROP**
WOB Average	**3,988**	6,467	**39% Less WOB**

Table 2 – Comparison of Data for 9 SlickBore System runs versus 12 conventional runs in the same offshore areas of South Timbalier, Ship Shoal, and West Cameron. All runs utilized performance motors.

DEPTH (FT)	ACTUAL TORQUE (FT-LBS)	PREDICTED TORQUE (FT-LBS)	EQUIVALENT FRICTION FACTOR
3510	3000	770	0.100
4140	3175	976	0.010
4998	3650	1734	0.060
5762	4775	2985	0.140
6430	6893	4121	0.255
7192	7063	5206	0.193
7954	7688	6357	0.178
8717	7500	7519	0.137
9477	7750	8694	0.121
10239	9063	9913	0.136
11383	10563	11750	0.136
12145	10781	13877	0.122
12907	11313	15205	0.121
13662	13938	16553	0.150
14325	14643	18093	0.150
		AVERAGE	0.146

Table 3 – Friction factors calculated using actual field data for a well with 109 degrees of azimuth change and open hole interval of 11,127 ft. This value compares to a typical value of 0.18-0.22 for synthetic mud on other wells.

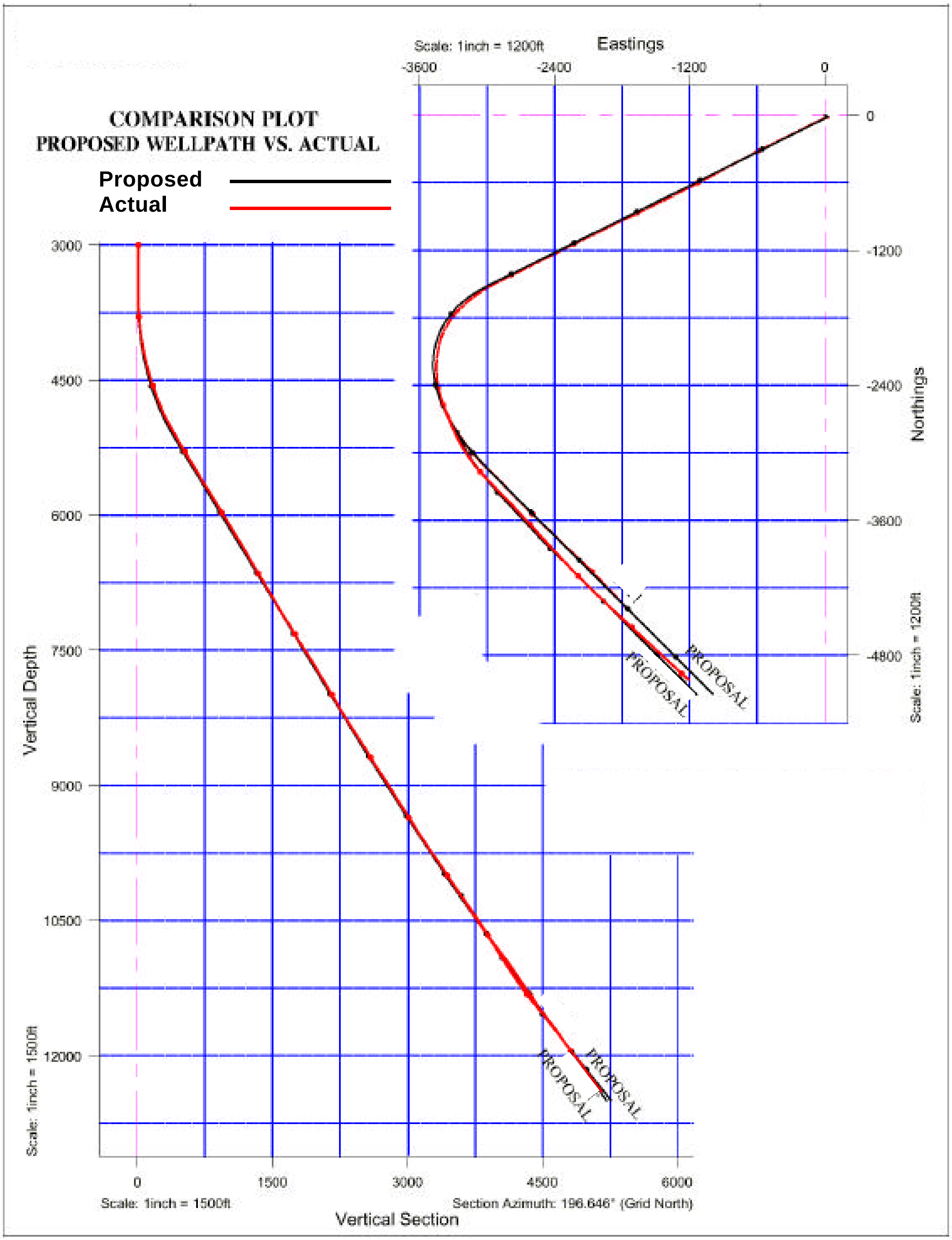

Figure 2 – Planned versus actual well profile for well in Ship Shoal.