SPE/IADC 67818

Tortuosity versus Micro-Tortuosity - Why Little Things Mean a Lot

Tom M. Gaynor, David C-K Chen, Darren Stuart, and Blaine Comeaux, Sperry-Sun Drilling Services, a Halliburton Company

Abstract

Tortuosity is commonly defined as the amount by which the actual well bore deviates from the planned trajectory. Elimination of excessive tortuosity has been regarded as a critical success factor in extended reach drilling operations. In this paper the authors will refer to "micro-tortuosity", not measurable by survey data, in which the hole axis is a helix instead of a straight line. It is argued that this is Lubinski's "crooked hole" described in the early 1950's. The paper presents a study of micro-tortuosity using field data from hundreds of wells. The paper details how and why micro-tortuosity occurs and the negative impact micro-tortuosity can have on the entire drilling operation. The paper also presents a solution that eliminates or drastically reduces micro-tortuosity.

Field results will be presented to demonstrate that micro-tortuosity is in fact the dominant component of the total tortuosity.

Introduction

Tortuosity has been recognized recently as one of the critical factors in extended-reach well operations[1,2,3]. The effects include high torque and drag, poor hole cleaning, drillstring buckling and loss of available drilled depth, etc. Conventional wisdom has always held that tortuosity is most often generated by steerable motors while attempting to correct the actual well trajectory back to the planned trajectory. However, in the early days of drilling in the mid-continent area of the United States, drillers observed a problem with running tubulars into wells. A vertical well drilled with a 12-1/4" bit would not drift 12-1/4". This led Lubinski et al.[4,5] to develop a formula for determining the minimum drift size for a hole drilled with a given collar and bit combination (or the reverse). This became known as the "crooked hole country" formula. Thus there was early recognition of the potential for problems due to the fact that the wellbore was not straight. This recognition predated the first use of steerable motors by some 30 years.

Today, several types of drilling tools are targeted at achieving reduced hole tortuosity as measured by survey data, with a view to reducing torque and drag. Obvious examples are adjustable gauge stabilizers and adjustable gauge motors, and, more recently, rotary steerable systems. In parallel, it is commonly suggested that bent-housing steerable motors increase tortuosity as measured by survey data by mixing high dogleg sliding footage and low dogleg rotating footage. In brief, low dogleg equals low torque equals "good", high dogleg equals high torque equals "bad". Recent evidence suggests that any torque and drag benefits derived from reducing dogleg as measured by survey data (macro-tortuosity) are likely to be completely overwhelmed by the torque and drag generated by poor wellbore quality (micro-tortuosity).

In the last two years, over 200 wellbore sections have been drilled using long gauge bits, primarily in pursuit of drilling improvements broadly encompassed by the term "hole quality". Most of these bits have been run on steerable motors; some, on rotary steerable systems. Modeling, measuring, and comparing torque and drag values for sections drilled with long gauge bits and with short gauge bits immediately showed two surprising results. First, there is no dramatic difference between the resulting torque and drag values for steerable motors versus rotary steerables when both use similar bits. Secondly, there is a significant difference between torque and drag values for long gauge bit runs versus short gauge bit runs regardless of the method used to drive them. The use of long gauge bits also gives a clear improvement in activities that might be expected to benefit from improved hole quality or reduced micro-tortuosity. These include hole cleaning, logging operations, resultant log quality, casing runs, and cementing operations.

Quantifying these differences by "back-calculating" the friction factors commonly used in the torque and drag model shows a general trend. The friction factors that give accurate results for long gauge bits are much lower than the values necessary for obtaining accurate results when using short gauge bits. Coupled with the observable field results, this suggests that attention to hole quality is likely to have a far greater effect on well design limits, particularly in extended reach drilling, than will minute attention to matching directional survey results to the ideal well proposal.

Thus, we believe that micro-tortuosity is far more important than the commonly known "tortuosity" in determining the resulting torque and drag and overall wellbore quality. In addition, we will show that micro-tortuosity is highly dependent on the bit and we will discuss field results that support the contentions above.

Tortuosity vs. Micro-Tortuosity

To explain the difference between tortuosity and micro-tortuosity, we will first explain how tortuosities are defined and measured.

Planned Tortuosity (T_p) is the summation of the total curvature (inclination and azimuth change) in the planned wellbore divided by the well depth. The result can be expressed by either the radius of curvature or, as its reciprocal, in degrees per 100 feet so as to be consistent with measurements of dogleg severity. For example, in a well that builds from vertical to 60 degrees with no change in azimuth, the total curvature is equal to 60 degrees. If the total depth of the well is 10,000 feet (3,048 meters) the Planned Tortuosity is 60/(10,000/100) or 0.6 degree/100 ft.

Tortuosity (T) is computed from the final well survey by summing all the increments of curvature along the well and dividing by the well depth (total tortuosity), then subtracting the planned tortuosity. In conventional wisdom, tortuosity is approximately the same as macro-tortuosity created by the local dogleg severity associated with the use of steerable motors attempting to maintain or correct the actual well trajectory on course with the well plan. The recent development of rotary steerable drilling systems was to provide smooth wellbore curvature that potentially could minimize all the tortuosity. Thus conventionally, the tortuosity (T) of the wellbore is equal to the total tortuosity (T_T) minus planned tortuosity (T_p) or

$T \approx$ Macro-Tortuosity $= T_T - T_p$ (Conventional Wisdom)

In their paper describing wellbore profile optimization, Banks, et al.[1] stated that wells drilled without regard to "smoothness" could have tortuosity values as high as 0.7°/100 ft while smoother wells could have values approaching 0.3°/100 ft. The "smoothness" to which Banks, et al. were referring had to do with the "kinks" imposed in the process of trying to steer the well back to the desired well plan with a steerable assembly.

Micro-Tortuosity (T_m) is defined as the tortuosity that occurs on a much smaller scale as compared to macro-tortuosity. We will demonstrate that the primary source of micro-tortuosity is borehole spiraling, where the hole axis is helix instead of a straight line. (Despite this the authors have stuck with the commonly used term spiralling.) Micro-tortuosity differs from macro-tortuosity in that (i) it occurs on conventional assemblies as well as motor assemblies (and rotary steerables, for that matter), and (ii) it creates a uniform spiraled wellbore that can only be detected by advanced wireline survey techniques or MWD caliper tools. Unlike more randomly occurring (and easily measured) localized washout, a spiraled borehole can last several thousand feet and can occur across a range of different formations. The effect of washout is therefore considered minor in comparison to the impact of thousands of feet of spiraled borehole. The authors also suggest that what has historically been classified as "rugose", "corrugated", or "ledged" hole, is more likely spiraled hole.

Spiral hole was first mentioned by MacDonald and Lubinski in a paper in 1951[4]. They reported that a spiral hole, though it has no objective rate of change in angle, could develop serious key seating difficulties, drill pipe wear on intermediate casing, etc. Lubinski used the term "tight spiral" to emphasize the high torque and drag associated with the spiraled wellbore.

We believe that the tortuosity (T) of the wellbore should consist of the macro-tortuosity and the micro-tortuosity as

T = Macro-Tortuosity + Micro-Tortuosity

In the past, the micro-tortuosity associated with a spiraled hole has been lumped into the crude "friction factor" value in torque and drag models. As a result, even with the introduction of new rotary steerable drilling systems which should have minimized all the local dogleg severity (macro-tortuosity), the observed field friction factors are still much higher than the coefficient of friction between steel and rock measured in a laboratory. This suggests that a significant portion of the torque and drag created by micro-tortuosity still exists downhole. We believe that micro-tortuosity occurs in most of the wellbore in the form of hole spiraling. Only by recognizing and removing micro-tortuosity can one drill a truly smooth wellbore. Based on the above hypothesis, the torque and drag (and the associated friction factor) in a wellbore with little to no micro-tortuosity should approach a level that is lower than has ever been seen before. We will demonstrate that in the following sections.

Mathematical Model of a Spiral Hole

The geometry of a spiral wellbore as defined in a Cartesian coordinate system is:

$X = r * \cos\theta$ ------- (1)

$Y = r * \sin \theta$ ------- (2)

and

$Z = P * \theta / (2\pi)$ ------- (3)

In which r and P are the radius and pitch of the spiral, respectively. The wellbore depth S can be calculated as

$S = [P^2 + 4 \pi^2 r^2]^{½} * z/P$ ------- (4)

and the curvature of the spiral hole can be expressed as

$K = 4 \pi^2 r / (P^2 + 4 \pi^2 r^2)$ ------- (5)

Thus, for a typical 5' pitch and 0.5" radius helix, using Eq. (5) the wellbore curvature K is calculated to be 0.0656 1/ft or a dogleg severity of 376 deg/100'.

Because of this high equivalent dogleg value, the drill collars and drill pipe cannot possibly conform to the spiral. If the BHA is slick, the collars will lie on the crests but tool joints will tend to hang up. If the collars are stabilised, either the BHA distorts to accommodate micro-tortuosity or the stabilisers attempt to ream the hole straight. Either way increased torque and drag is probable and this is not accounted for in T & D models

The collars will act to limit the amount of lateral movement of the bit off the centerline of the hole. Thus the spiral amplitude will be determined by the relative size of the bit and collars. This is exactly the function described by Woods and Lubinski[5] in determining the maximum wellbore "drift" of a "crooked hole". Lubinski calculated the maximum drift created in a crooked hole as

Drift = (Bit Diameter + Collar Diameter) /2 ------- (6)

Figure 1 shows the two-dimensional schematic of Eq. (6) and the drill collars in a spiral hole.

Figures 2 and 3 show two spiral borehole images taken from the wireline CAST (Circumferential Acoustic Scanning Tool) tool in a well in South America. The evidence of hole spiraling is presented in the strong diagonal response of the CAST images running across the compressed and expanded 2-D images presented in tracks 1 and 2. The reverse 3-D image presented in track 3 clearly indicates the wellbore spiraling while it was being drilled. Note that the spiral seemed to change its direction from time to time and had a pitch length was about 2 feet.

Figure 4 shows a spiral hole detected by a differential caliper tool on a wireline density measurement at a well in Gulf of Mexico. The log indicates that the hole is under gauge approximately by 1.5" every 4 feet and rarely over gauge. This phenomenon is repeated over thousands of feet on this log. This section was drilled by a 9-7/8" bit and 6-3/4" collars. Using Eq. (6) the drift (new wellbore) is calculated to be 8.31", a 1.56"(16%) reduction in wellbore OD which is exactly the same magnitude measured by the wireline tool. The reduction in the cross section area (drift vs hole size) is calculated to be 22.32 in^2 (29%). As a comparison, Figure 5 shows a perfectly gauge hole drilled with a new steerable system (a matched long gauge bit and positive displacement mud motor). The entire 12,000 ft interval was drilled in only 2.7 days with no short trips

Although a spiral hole creates higher torque and drag, the extra wellbore length due to spiraling is usually negligible. For example, using the same parameters above in Eq. (4), S = 1.014 z, representing a 1.4% increase of wellbore length drilled by the bit. Only for cases of very large radial clearances (17-1/2" bits and 9-1/2" collars) can the additional length increase to perhaps 3%, or an extra 30 feet drilled per 1000 feet of hole.

Solution for Micro-Tortuosity: Long Gauge Bits

The ability of any bit to move off the centerline of the wellbore is determined by the gauge length on the bit, the amount of side cutting structure on the bit, and the stabilization of the bit and BHA. Other factors may play a role in reducing the tendency to move off center, such as anti-whirl feature, but these factors are addressing symptoms rather than causes.

The concept of preventing side-cutting to improve hole quality is not new as machinists have taken advantage of it for years. A conventional twist drill for drilling through metal is furnished with a cutting structure that cuts only in the direction of the tool's long axis, and the spiral flutes serve only to stabilize the cutting structure, and "burnish" the sides of the hole. Until the flutes begin to stabilize the cutting structure, the drill will tend to precess in the same direction as drill rotation. This can readily be observed using a domestic electric drill, and explains why the hole being drilled is often triangular until the stabilizing flutes begin to control this movement. If they did not exist, the drill would continue to precess, and the resulting hole would be triangular in section, following a helical path.

Since the mechanics that governs machining metal is identical to that in rock, there is no reason to expect that preventing fixed cutter bits contacting the side of a wellbore will have any different result. Any tour of a machine shop will immediately reveal that a drill press, designed only for cutting tools that do not side cut (twist drills or reamers), is relatively slender. Milling machines, designed to cope with side-cutting tools, are massive, with stiff, well-supported spindles to give them the stiffness to resist side-cutting forces. This offers a possible explanation for the observation that PDC bit tests carried out in laboratories (on rigs that are much more like milling machines than like drilling rigs), produce results that have never been seen in the field. A drill string can never approach the lateral and torsional stiffness of a milling machine. However, a drill press, designed only to drill holes – which is what we want to do – has no great torsional, and often very little lateral stiffness. Instead, the cutting tool provides the solution. The drilling equivalent of a twist drill is *a long gauge bit*.

There is now abundant evidence that hole spiraling exists, whether this evidence is anecdotal, visual (from imaging tools) or by inductive reasoning from logs with an otherwise inexplicable periodic variation or tools with an otherwise inexplicable wear pattern. There is also abundant evidence that long gauge bits minimize or more often eliminate hole spiraling. Since the drilling industry depends on steering, if "long gauge bits do not steer" then this piece of information is interesting, but has no practical application. Once it is discovered that long gauge bits can be made to steer, initially on specially designed motors, and subsequently on point-the-bit rotary steerable tools, then the information is worth re-examining.

This solution can be demonstrated by recourse to Lubinski's crooked hole equation in Eq. (6). It demonstrates that the drift of a hole is controlled by the diameter of the drill collar directly above the bit. A non-spiraled, high quality hole will have a drift diameter equal to its gauge, presumed to be the nominal bit diameter. It is easy to demonstrate that if the collar directly above the bit is in fact the same diameter as the bit, then drift equals hole gauge, and the hole must possess no spiraling. Running 12 ¼" collars in 12 ¼" hole would pose problems. Running a bit with a 12 ¼" sleeve directly above the cutting structure (a long gauge bit) does not.

When this thinking has been applied to oil field bit design, the results have been surprising. Straighter holes have resulted in friction factors that defy conventional expectations. Bit life has been extended greatly. Circulation time as a percent of below-rotary hours has been reduced to 10-12% on average, demonstrating the efficiency with which the cuttings are being circulated out of the well. Short trips have been reduced or eliminated. Log quality and ease of running logging tools has been improved. Cement job success rate has been nearly 100%, with cement bond logs to demonstrate the high quality of the job. MWD and LWD failures have been reduced due to the drastic reduction in downhole vibration. Lost-in-Hole risk has been reduced. Entire hole intervals have been drilled in record times repeatedly.

It is important to note that the drilling system employed required changes to the bit design as well as changes to the positive displacement mud motor design.

While these benefits apply to the vast majority of wells being drilled today, the reduction in friction delivered by this new system is of particular value for pushing the extended reach envelope even further than previously thought possible.

Quantifying Tortuosity and Micro-Tortuosity by the Friction Factor

There are several ways to quantify tortuosity, such as using the surface torque[1] or using the friction factor in the torque and drag modeling as proposed in this paper. More than one hundred wells have been analyzed where the friction factors were back-calculated, that is, the value of friction factor necessary to generate model results that matched observed field data was calculated. All of the wells were drilled with conventional BHA's, including motor and rotary assemblies.

Table 1 shows the results from the study. As can be seen from the table, the friction factors can vary considerably, depending on mud type and whether the hole is open or cased. The friction factors are normally less in casing than in open hole. It has always been assumed that this was due primarily to the lower relative coefficient of friction between steel on steel (drill pipe on casing) compared to steel on rock (open hole). We propose that a larger effect is the elimination of micro-tortuosity (spiraling) once the casing has been run. Our reasons for believing this will become clear shortly.

These friction factors have been used for some time now for the purpose of predicting torque and drag on planned wells. However, with the introduction of this new positive displacement mud motor and long gauge PDC bit drilling system[6], it became apparent that the generic friction factors used for everyday wells were no longer applicable to wells drilled using this new system. The pick-up, slack-off and torque values predicted using the conventional friction factors were considerably higher than those observed in the field, indicating that the friction factors were set too high for accurate torque and drag prediction for the new drilling system.

In order to improve predictions when designing future wells that would utilize this new drilling system, we analyzed several North Sea runs that had been drilled with the system to determine an accurate friction factor. We found that on wells drilled with the new system and using pseudo oil based mud, the average friction factor value was 0.12. This compares to 0.17 for conventional assemblies with the same mud type, a dramatic 30% reduction. As can be seen from Tables 1 and 2, the open hole friction factor value using this new system is actually lower than the calculated casing friction factor in conventional assemblies. This was a surprising revelation. The authors suggest that the drag measurements on which the casing friction factor is based are normally recorded soon after the casing is run, perhaps on the shoe drill-out run. This initially high drag value can be expected to drop with every rotating hour as the inside of the casing becomes polished. Hence the friction will reduce with time giving a lower friction factor value. We have found from further study that the open hole friction factor using this new system is almost identical to cased hole friction factor after polishing, further proof that the reduction must be down to micro-tortuosity. Figures 6 and 7 show "typical" calculated friction factor analyses using this new drilling system at two North Sea wells.

In order to simulate tortuosity on well plans, a tortuosity scale factor is applied to the back-calculated actual friction factors (See Table 2). Normally for conventional assemblies, Halliburton has used a tortuosity scale factor value of **1.34**. Using this new drilling system, it was noted that the tortuosity scale factor was reduced to **1.14**. This would mean that in our example of Pseudo Oil Based Mud the planning friction factor when using this new system will only be **0.14** (0.12 x 1.14) as opposed to the "normal" value of **0.23** (0.17 x 1.34) for conventional assemblies.

Field Examples of Micro-Tortuosity

Micro-tortuosity affects almost every aspect of drilling and completing a well. Due to space limitations we have focused on the most important areas, based on the significance of the impact on drilling time and cost.

• Bit Life and MWD/LWD Tool Reliability

Bits that designed to cut away the side of the hole as well as the hole in front of it tends to drill a spiral hole. They include short gauge length bits or bits with side-cutting structure[7]. These types of bit are also prone to vibrations and "whirl". As most drillers are aware that impact damage is a primary cause of PDC bit damage. Thus, spiral hole is often associated with bit vibrations resulting in shorter bit life.

The same vibration that destroys the bit also travels up the drill string and can lead to a premature MWD/LWD failure. By stopping the vibration before it can initiate, the MWD/LWD system reliability should improve. Data from multiple incidents where vibration-related failures have occurred, utilizing the new drilling system has had a dramatic impact on eliminating or reducing the frequency of tool failure.

• Hole Cleaning

Due to the rugosity of the spiral wellbore, cuttings will travel a tortuous path and will encounter a trough every 2 to 10 feet (dependent on the actual pitch of the spiral). This will lead to additional circulating time as well as extra time for backreaming and short trips in an attempt to dislodge the trapped cuttings. When using the new drilling system (utilizing the long gauge bit), entire intervals have been drilled without short trips and with greatly reduced circulating hours. In one instance, a 12,000-foot open hole interval in the Gulf of Mexico was drilled with no short trips. The entire interval was drilled in only 2.7 days.

• ROP

Stabilizers will tend to hang up in a spiral hole, especially in a non-rotating ("sliding") mode. This mechanism explains the reduction in sliding rates of penetration (ROP) relative to rotating ROP that is generally recognized as a universal phenomenon. If spiraling could be eliminated, one would expect to see a resulting increase in sliding ROP relative to rotating ROP. In fact, this is exactly what has been seen when using the new drilling system that utilizing the long gauge bit. In some areas sliding ROP has been increase to within 80% or more of the rotating ROP. Thus, the penalty for sliding is reduced. This opens the door for the directional driller to spend more time keeping the well closer to the well plan while achieving a respectable ROP, thus reducing the macro-tortuosity in the well also.

• Stabilizer Wear

Stabilizer hang up in spiral holes would also result in the excessive wear on the leading and trailing edge of stabilizers that has been observed on numerous wells. This is the area that would contact the spiral every pitch, and also would tear out the new formation when backreaming is done. The short gauge bit that originally allowed the spiraling to occur would not perform this function, because at any point in the hole, the bit will prefer to follow the relatively gauge hole it originally cut, and so will follow the spiral in and out of the hole. The job of backreaming is left to the stabilizers. A key identifier for spiralled hole is that stabiliser wear advances *along* the hole axis, not *perpendicular* to it.

• Torque and Drag

The torque and drag in the wellbore often determine the success of drilling extended reach or horizontal wells. Torque and drag data gathered from the new drilling system show a 40% reduction in the friction factor value required for the modeling. This is a result of eliminating micro-tortuosity.

• Logging Tool Response

Spiraled boreholes have long plagued wireline and LWD service companies and have led to totally ambiguous responses from resistivity, density, neutron, and other logging sensors. This is due to the fact that the logging tool will be supported on the low side of the hole by the peaks in the spiral. If the hole is in fact spiraled instead of corrugated, then the opposing side of the hole will be "in phase" rather than "out of phase" as would be expected for a corrugated hole. In simple language this means that opposite every peak on the low side will be a peak on the high side, not a valley. See Figures 1 to 3.

Figure 4 illustrates a spiral hole detected by a differential wireline caliper tool. The borehole fluctuates between almost perfectly gauge and 1.5" under-gauge. This is due to the fact that the caliper arm is regularly moving from a peak to a valley on the high side. When it measures the peak, the tool has its "back against the wall" at that point, so the distance is exactly the bit diameter. At all other times its "back" is spanning the valley between two peaks, and it is therefore unable to conform to the borehole center, and thus measures

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