

The Limits of Backreaming, Hole Enlargement, and Casing to Mitigate Wellbore Tortuosity

Ben Leonard and Serik Seitassanov, Chevron U.S.A. Inc.

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Abstract

Wellbore tortuosity, doglegs and micro-doglegs are seen as contributing to a number of downhole well construction problems, including casing wear, stuck pipe and high torque & drag. In some instances the tortuosity (used interchangeably with dogleg from here on out) is induced by formation changes, but often it is attributed to directional work from motors or rotary steerable assemblies. In cases where undesirably high doglegs are introduced during drilling, mitigations to the increased risk are possible via use of select band casing, additional thread protection or mechanical means of preventing drillpipe from wearing on casing. In some instances, the operational decision is made to take the remedial step of reaming out the section of concern. There is sometimes a perception that reaming will smooth out tortuosity by slightly enlarging and/or smoothing the wellbore. Likewise the process of underreaming and hole opening is sometimes thought to smooth out micro-doglegs and that, once casing is run, localized dogleg severity variation will be reduced. These activities may be planned based on local experience and rules of thumb and are not necessarily data driven decisions. This paper will present with a series of case studies in which reaming, hole enlargement and casing had a minimal impact on tortuosity.

This is demonstrated with MWD and/or gyro survey data before and after these activities. The impact of wellbore geometry, survey frequency and location will be discussed and some basic conclusions on when tortuosity may or may not be reduced.

Introduction

Tortuosity in wellpaths contribute to well construction execution issues including stuck pipe, trouble getting casing to bottom, and inability to pass critical components of a drill string or completion. Many tools and pieces of downhole hardware have dogleg ratings and maximum dogleg severity may be a critical design criteria. While tortuosity induced by directional drilling is often unavoidable, efforts to minimize or reduce unwanted tortuosity are included as a matter of design and best practice.

In some cases, the concern is micro-tortuosity or micro-doglegs, where there is a change in direction over a sufficiently small distance that the equivalent rate of change is

relatively large. These micro-doglegs are a direct consequence of slide drilling with a directional, bent-sub motor assemble. The action of stopping drill string rotation, holding a constraint toolface and bend orientation, and drilling necessarily introduces a higher localized dogleg. Moreover, the rate of change in angle is usually not linear over the length of a slide. Often the most effective portion of the slide in changing angle is at the end. Additionally, other sources of micro-tortuosity and high, undesired doglegs are present in drilling activities, including from washouts, key-seating, and systematic downhole tool pad activation.

Despite mitigations in planning and execution, undesired micro-doglegs can occur. Remedial efforts are sometimes undertaken to minimize the impact of these locations. Typical remediation includes backreaming, either after a stand is drilled or as a dedicated activity, spending addition time working the high angle location. As the hole is worked, it is assumed the micro-dogleg will be smoothed out. Hole opening and enlargement activities are also sometimes seen as reducing micro-doglegs by averaging out the high angle location during the increase in borehole diameter. The stiffness of casing run and covering a high micro-dogleg location is also thought to prevent the casing from conforming to the direction change, again smoothing out the tortuosity.

Surprisingly, given the concern and cost associated, guidelines to the effectiveness of micro-tortuosity reduction activities are not supported by a significant body of theory or measured evidence. In the current cost conscious environment and high daily spread rates encountered in many locations, it is unfortunate that time and effort will be devoted to activities that often appear to have minimal documented benefit, while increasing open hole time and well construction cost. This paper will attempt to provide some measurement on the actual ability to impact DLS and help inform decisions on whether undertaking deliberate, additional efforts to smooth out micro-doglegs warrant the cost on future wells.

Impact of Casing and Hole Enlargement

Well construction almost always consists of the installation of casing of a smaller diameter than the borehole in which it is placed. It is sometimes assumed that the installation of casing will smooth out localized tortuosity. This may be considered to help mitigate high doglegs when considering later casing

wear or subsequent torque and drag analysis.

The exact mechanism of this smoothing is not well described, but is generally considered to be due to the relative stiffness of the casing and its freedom to take a straighter path than the wellbore. The larger the difference in hole size and casing size, the greater the opportunity to reduce the effective tortuosity for the next hole sections.

A further opportunity to reduce tortuosity could be during hole enlargement or underreaming. In either case, the additional cutting action in the wellbore might be able to reduce ledges or other discontinuities.

The following case studies present survey data before and after the installation of large diameter casing. In many cases, underreaming or hole opening was also performed. However, despite these actions, there is little apparent change in the tortuosity as measured by dogleg severity.

Extended Reach Case Study

A pair of nearly identical horizontal wells provides a robust data set to analyze. Both wells included approximately 3,000' of intermediate section that included directional kickoff and significant build work drilled with a 12 1/4" pilot hole assemblies as seen in figure 1. For operational reasons, Well 1 was drilled with a motor BHA and utilized a separate hole enlarging assembly with a 19" underreamer, while Well 2 used a RSS drilling BHA and a separate hole enlarging assembly with a 20" underreamer. After the wellbores were enlarged, 16" casing was run and cemented on each.

The survey data sets included standard measurement while drilling (MWD) surveys while drilling the pilot hole, while underreaming, and high resolution gyro after casing was run.

This provided a high quality, comprehensive set of surveys, which was important, as minimizing dogleg severity was considered critical to delivering a successful well. Specifically, DLS was to be kept below 3.0°/100'. Upon detailed review of the data, and as a surprise to some, it was seen that there was no measurable impact of any of the activities normally associated with or proscribed for DLS reduction.

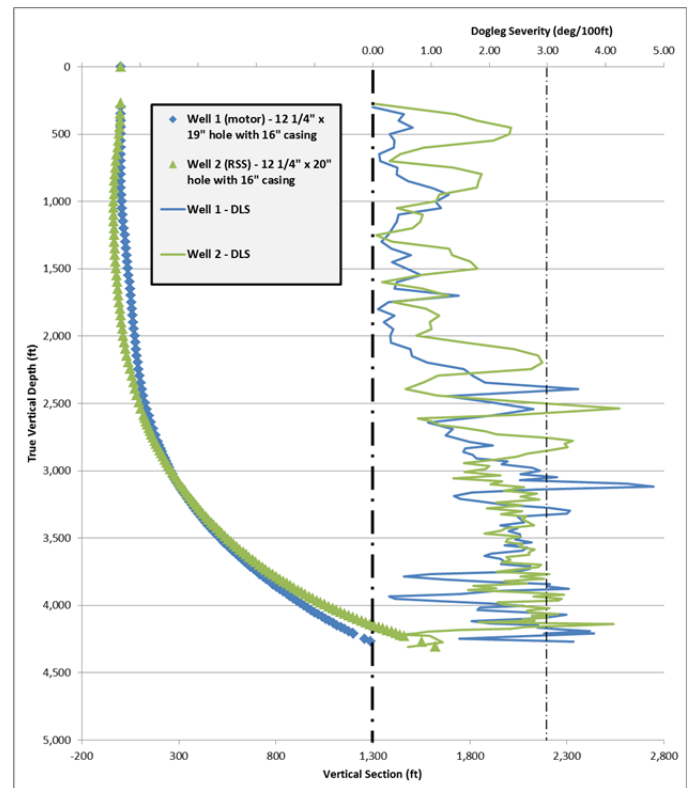


Figure 1: Well 1 & 2 Intermediate Section Vertical Section and DLS

The subsequent sections on each well were both drilled with a 12 1/4" pilot hole RSS assembly to a final depth of approximately 10,700' as seen in figure 2. Well 1 then used a 14 3/4" staged hole opener and 16 1/2" underreamer assembly to open up the hole. Well 2 was similarly enlarged, although it used a 17" underreamer. MWD data was collected while drilling and hole enlargement, but gyro data was not collected.

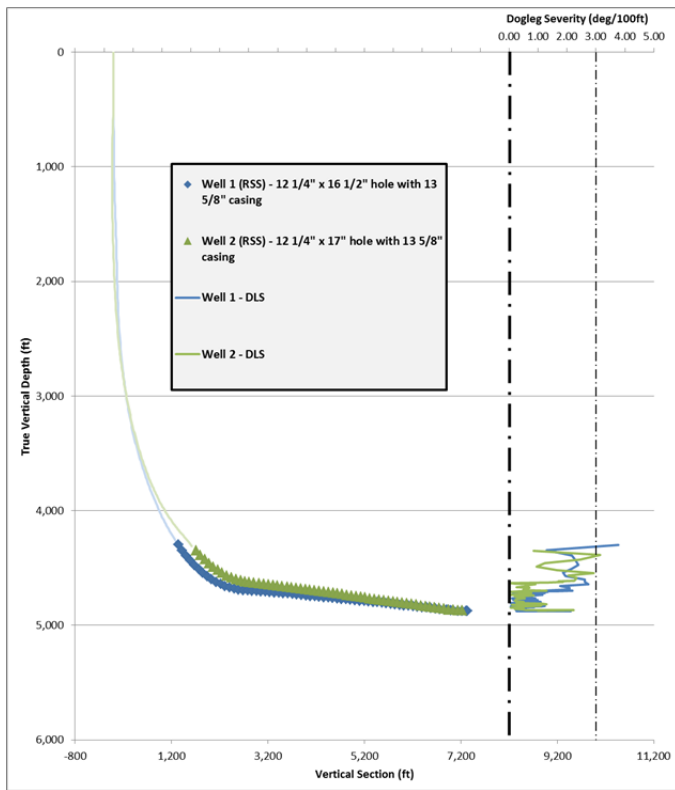


Figure 2: Well 1 & 2 Horizontal Section Vertical Section and DLS

As can be seen, both wells exceeded the desired $3.0^{\circ}/100'$ target in both sections on the definitive surveys. This was seen in real time and confirmed upon detailed review of the stationary surveys from the pilot holes. It was hoped that perhaps, while reaming out of hole to remove cuttings, and that as the hole was enlarged and then cased, some of the dogleg spikes would be smoothed out and the final result would be closer to the targeted DLS's.

Careful review of the data revealed very limited impact of hole enlarging on the measured dogleg severity. This was most evident in the first hole section which had the addition of gyro data taken after the casing run. The results can be seen in figures 3 and 4. Excellent agreement is seen between the DLS measured before hole enlargement, after, and post casing. No evidence is seen of smoothing out the peaks in DLS during the directional work and the gyro data reads as high or higher doglegs at the most extreme points.

Of note is the correlation on well 1, which was drilled with a motor BHA. There had been a greater expectation of leveling out the DLS that resulted from sliding, but there is no data to support this belief. The before and after hole enlarging has the same tortuosity, just as with the RSS assembly drilling on well 2.

While a RSS assembly is generally expected to have a smoother profile, well 2 saw some significant changes in dogleg as the directional drillers tried different power settings on their tools. In a few instances, a power setting that was inappropriately high was used and DLS increased above the $3.0^{\circ}/100'$ criteria. When this was seen on the realtime near bit

inclination, the power setting was reduced. The result was a few DLS spikes due solely to the BHA settings and not formation or flow rate change.

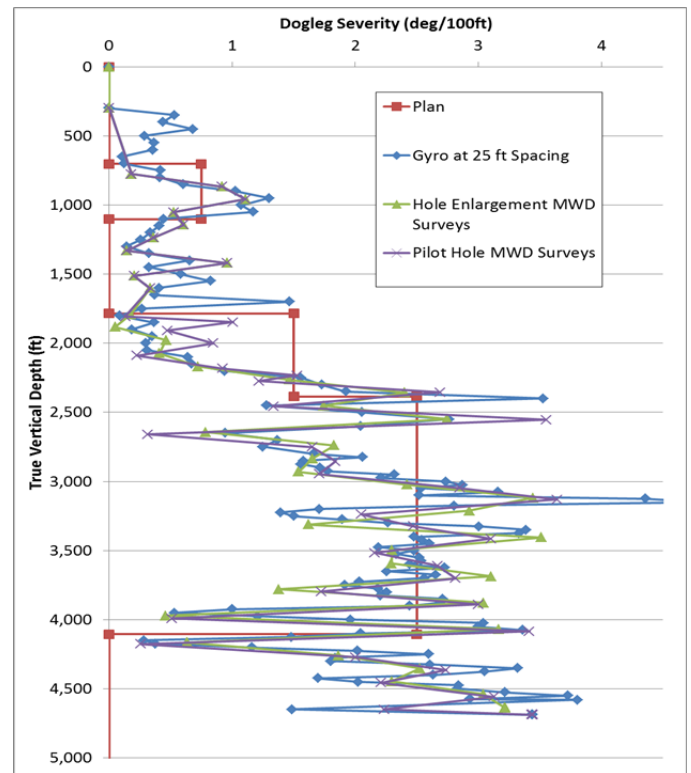


Figure 3: Well 1 Intermediate Section Planned and Measured DLS

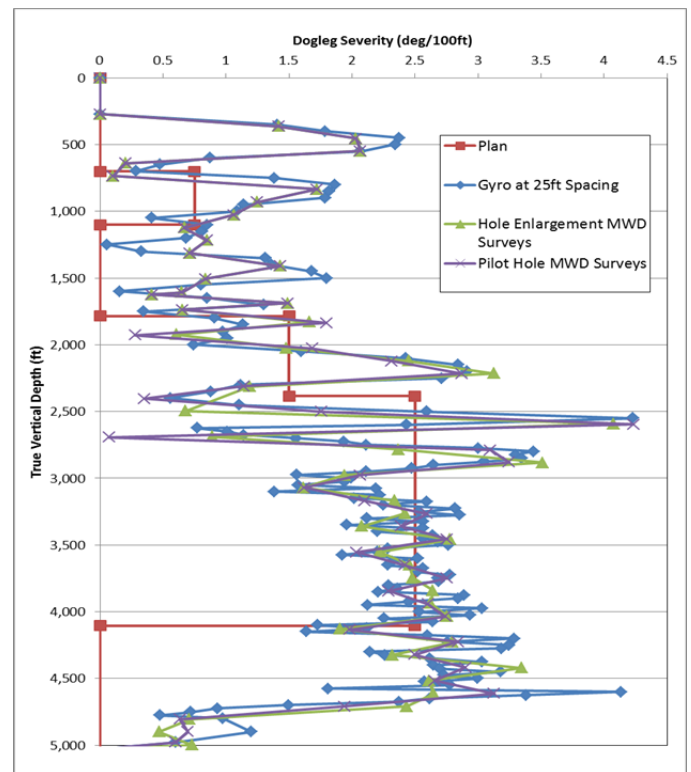


Figure 4: Well 2 Intermediate Section Planned and Measured DLS

Lack of gyro data in the horizontal section prevents the same sort of analysis, however static MWD survey inclination data is available from the 12-1/4" pilot hole BHA and the 14-1/2" x 17" hole enlargement BHA. Additionally, continuous inclination data is available from the RSS as well as the MWD's in both runs.

Figure 5 shows good correlation between the continuous inclinations of both the MWD and RSS with the MWD static surveys while drilling the pilot hole, which is generally to be expected. The MWD in the hole enlargement BHA was placed between the 14-1/2" staged hole opener and the 17" underreamer. While this is not optimal MWD placement, there is generally good agreement between the static and continuous measurements from the two BHA's.

No clear smoothing of changes in inclination can be seen in the continuous inclination of the hole enlargement BHA MWD, and figure 6 shows that in sections there is some deviation and in others, better apparent overlay with the RSS continuous measurement.

Comparison of tortuosity from the higher accuracy static measurements is affected by the staggered spacing of the survey stations. As will be discussed later, this can impact DLS calculations and provide a distorted analysis.

This example is obviously not definitive, but shows that in this case no consistent localized changes in inclination are seen simply through hole enlargement. Furthermore, the challenge of data analysis with variable survey spacing is illustrated as previous studies have shown (Stockhausen and Lesso 2003).

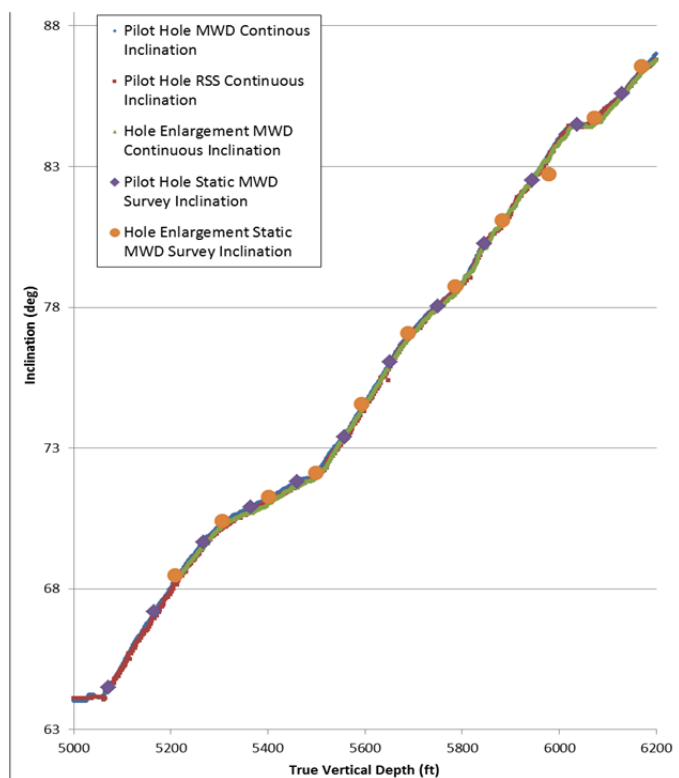


Figure 5: Well 2 Surveys and Continuous Inclination

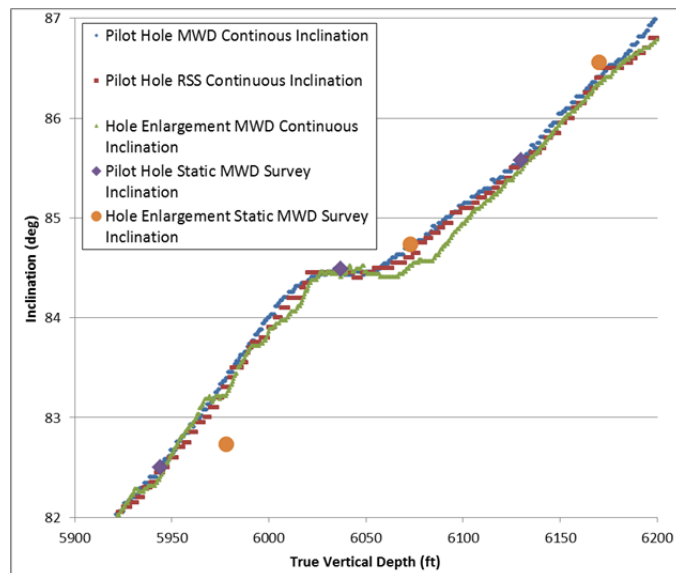


Figure 6: Well 2 Surveys and Continuous Inclination (Enlarged)

Build Section Case Study

Even without hole enlargement, it is worth considering whether the stiffness of casing will reduce local tortuosity in a relatively large hole. Well 3 is an example of a 12-1/4" hole drilled with a motor and subsequently cased with 9-5/8" pipe, and then cemented to surface. Numerous hard stringers were encountered while drilling and these were reamed prior to making connection. Additionally, the drilling assembly was backreamed out of hole. Following the casing run, a gyro was run on wireline.

Figure 7 shows a comparison of the gyro and MWD DLS measurements. With a single exception, there is no reduction in DLS despite reaming while drilling, backreaming out of hole, and running casing.

The outlier at 2,776' TVD is notable as it is taken at an irregular interval of 70'. The gyro survey stations are all at a 100' spacing and the MWD stations are mostly at a 90'-100' spacing. This places the survey in the middle of a slide, which can amplify the apparent DLS and suggests it is not a representative data point.

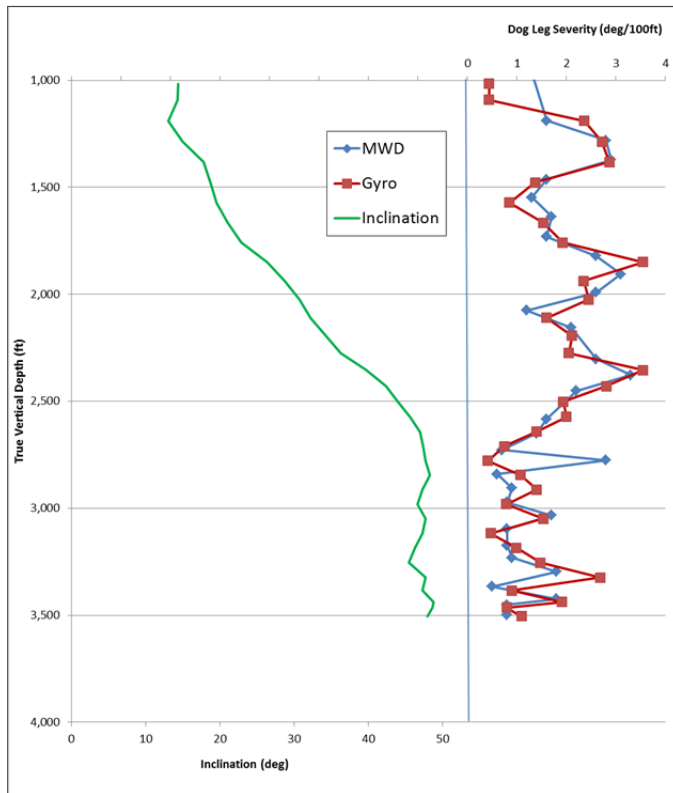


Figure 7: Well 3 Surveys Inclination as well as MWD and Gyro DLS

Impact of Backreaming

In some instances, concern about the impact of sections of high DLS is sufficient that remediation is undertaken. Often this takes the form of backreaming through the area of concern. More generally, entire stands may be reamed up and down with the intention of smoothing and elimination of ledges. Following the reaming, surveys are can be taken to assess the change in DLS.

With the increasing prevalence of rigs with top drives, and increasing well complexity, backreaming has become a common tool to address a number of hole problems (Yarim et al. 2010). It is common to backream out of the hole when cuttings beds remain in horizontal wells, when tight-hole conditions are expected, and generally when it could be problematic to simply trip out of hole.

The data review by the authors indicates that reaming activity does not clearly reduce tortuosity. However, as it is on the critical path, there is associated expense. Furthermore, rotating off bottom often subjects a BHA to additional shocks and vibrations as it is no longer stabilized by the bit being on bottom. Some operators have found that backreaming has continued as a best practice despite not being applied in the manner originally intended (Akers 2009). The time and drawbacks of remedial reaming should be considered critically to evaluate the cost/benefit trade off.

Deepwater Case Study

DLS in upper hole sections is of particular concern in

some deepwater designs due to casing wear concerns. RSS are typically utilized and build rates are modest. However, these casing strings may be exposed to hundreds of rotating hours and that may ultimately lead to reduction in the sealing capacity of connections.

In the following example, DLS outside of design parameters was observed while drilling a 16-1/2" x 19" hole section with a RSS BHA. At 11,002' a DLS over the 1.5 deg/100' criteria was measured by MWD survey.

Five and a half hours of critical path reaming and resurveying was performed. Table 1 shows the impact of reaming and then casing on the DLS of concern.

As- Drilled Surveys				
MD (ft)	Incl (°)	Azim Grid (°)	TVD (ft)	DLS (°/100ft)
10761.00	3.02	328.01	10748.69	0.29
10848.00				
10892.00	2.37	310.43	10879.54	0.80
10950.00				
11022.00	0.09	106.05	11009.51	1.89
Checkshots after Reaming while POOH				
MD (ft)	Incl (°)	Azim Grid (°)	TVD (ft)	DLS (°/100ft)
10761.00	3.02	328.01	10748.69	0.29
10848.00	2.30	332.51	10835.59	0.86
10892.00	2.10	317.36	10879.56	1.39
10950.00	1.01	320.17	10937.54	1.88
11029.00	0.04	69.34	11016.53	1.30
Cased hole Surveys (Inclination Only Surveys)				
MD (ft)	Incl (°)	Azim Grid (°)	TVD (ft)	DLS (°/100ft)
10761.00	2.99	328.01	10748.69	0.31
10848.00	2.41	332.51	10835.59	0.71
10892.00	2.13	310.43	10879.56	2.07
10950.00	0.99	320.17	10937.54	2.01
11022.00	0.08	106.05	11009.53	1.47

Table 1: Well 4 Surveys After Drilling, Reaming, and Casing

It can be seen that despite the time spent, there is no reduction in the maximum DLS. The reaming was undertaken with a surface rotation of 65 RPM and torque spikes were reported when working the stand. The lack of change in DLS suggests that the torque may not have been related to cutting action as much as vibrations acting on a large, unstabilized BHA with a 19" underreamer. Potentially this was magnified by the tortuosity, but the evidence suggests that the reaming had minimal impact.

Furthermore, the DLS remained after running 16" casing inside the 19" borehole. Given the near vertical wellpath, this suggests that large casing follows the localized DLS in vertical

hole as well as the high angle examples previous presented.

Discussion

To help understand why little or no change is seen despite reaming, enlarging, or casing, it is instructive to consider the geometries involved. Take the following example of a 100' interval with three curvatures as seen in figure 8. All three start and end at the same locations with the same angles, representing survey stations with the same depths and measurements.

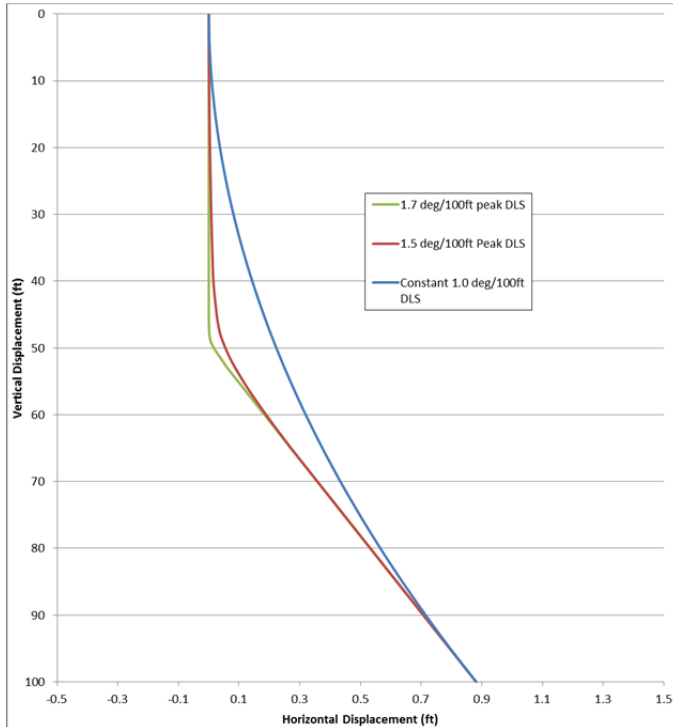


Figure 8: Example Changes in Wellpath and DLS

The first line (green) with a sharp change in angle will represent the initial well as drilled. Perhaps the intention was to drill vertical and due to formation or parameter change, the well kicked off and then continued to hold its new inclination. Upon reviewing survey data (continuous MWD or 1' gyro) the operator finds a few feet of DLS at 1.7 deg/100ft. A decision is made to ream and attempt to reduce the dogleg. If the operation is successful and reduces the peak dogleg to 1.5 deg/100ft, there is less than 1/2 of an inch physical shift, as seen by the second line (red). This is not likely to impact operations in a drilling environment. If the operator desires to achieve line 3 (blue), a smoothed path with a constant 1 deg/100ft dogleg, a significantly greater change is required.

To shift from line 1 to line 3 requires an additional 14% of hole volume to be drilled. This proportion is independent of hole size, and is a significant volume of rock to drill with only the side cutters of a bit or reamer. Given the generally reduced off bottom rotating speeds, cutting action, and energy transfer efficiency, it would not be surprising to need as long to ream and achieve the desired correction as it took to drill the stand in the first place.

The above example assumes that it is possible to direct reaming to cut on the desired side of the hole at the needed curvature. The authors contend that this cannot be taken as a given. In a near vertical hole, there will be a tendency for gravity to keep the BHA on the low side. Overcoming this to remove rock on the high side necessitates a drag force in front of the cutting action and a nearly full gauge cutter. This is problematic as sufficiently high drag would also be seen while drilling and reduce ROP. Furthermore, if the removal of rock from the high side accidentally exceeds the initial build rate of the desired curve, two more opposing curves are required to end up at the survey station with the correct inclination. Deviated and horizontal wells are more complex, but the assumption that off bottom rotation with cutters designed to drill down (not sideways) will remove a significant quantity of hard rock in the correct place and with the correct geometry should be challenged unless demonstrated with field data or adequate modeling. The data reviewed by the authors appeared to indicate that little change is made to hole geometry and probably the rock that is removed is along the path of least resistance.

Geometry also helps explain why surveys after casing do not seem to find significant reduction in DLS. Continuing with the example, if we assume that line 1 is the wellbore and line 3 is the desired casing path, the casing must have at least 2 inches of space between its OD and the wellbore ID on the high side to be free to follow the desired path. In this example geometry, the required space is independent of bit and casing size.

Many common casing configurations do not permit the needed space for this example and assuming the casing starts in the center of the well:

- 6" casing in a 8-1/2" wellbore
- 9-7/8" casing in a 12-1/4" wellbore
- 13-3/8"/14" in a 16-1/2" wellbore
- 16" casing in a 19" wellbore

Standard configurations that do work geometrically (though this does not mean they will necessarily follow the desired path) are either very large, such as 22" casing in a 26" hole or very small, such as 3-1/2" tubing in an 8-1/2" hole.

This analysis does not consider the impact of centralization that could further limit casing movement, not complex three-dimensional phenomena like RSS spiraling in a near vertical hole

Survey Practice Considerations

The implications on apparent tortuosity of varying the distance between survey stations has been reviewed in depth (Bang et al. 2015). This is a consideration in evaluating if any reduction in DLS has taken place.

High resolution gyro data collected at a 1ft interval is useful for detecting small scale phenomena, but challenging to interpret when comparing to MWD surveys as can be seen in figure 9.

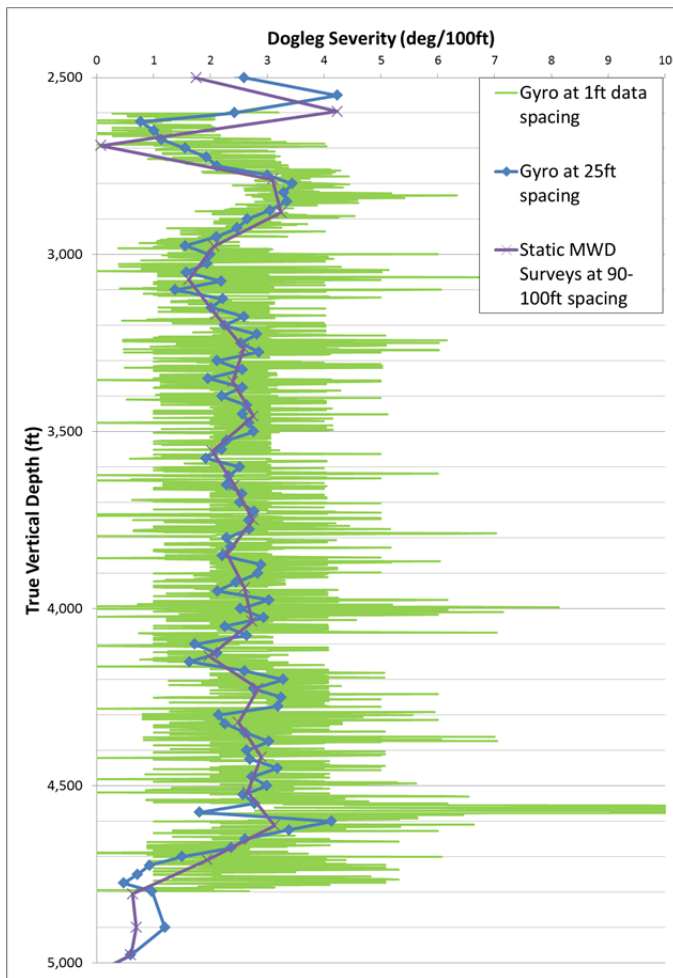


Figure 9: Well 2 Surveys and Continuous Inclination (Enlarged)

Simply comparing the 1ft surveys to the MWD surveys could suggest that there very significant micro-doglegs that are far in excess of the designed 3.0 deg/100ft. Filtering the gyro data to 25ft spacing provides a much clearer picture, one that appears to suggest that the cased hole DLS is very similar to the as drilled DLS.

Both the 1ft and 25ft gyro data are correct in that they are accurate representations of the tool measurement. However, the 1ft does not provide for easy comparative analysis or indication of wellpath quality. In the example of well 2, hookload measurements taken during the 16" casing run indicated a low friction factor, and not one typically associated with a DLS above 10 deg/100ft as shown by the 1ft gyro data.

When extrapolating 1ft data to deg/100ft DLS, an extremely noisy picture is created. Furthermore, what are actually fluctuations within a tool's range of accuracy can be magnified. A commonly listed inclination accuracy for downhole survey tools is 0.1 deg. If two successive 1ft survey stations had this degree of error in opposite stations, the implied DLS would be 20 deg/100ft. At 100ft spacing, the DLS appears to be 0.2 deg/100ft. This is an extreme and unlikely example, but helps to illustrate how inconsequential changes can be magnified at a high sampling frequency.

The selection of the exact survey point can make a difference in the measured DLS by changing the length that is being measured. It may be that a high DLS is seen in the normal survey, which raises concerns and reaming is performed in an attempt to mitigate the dogleg.

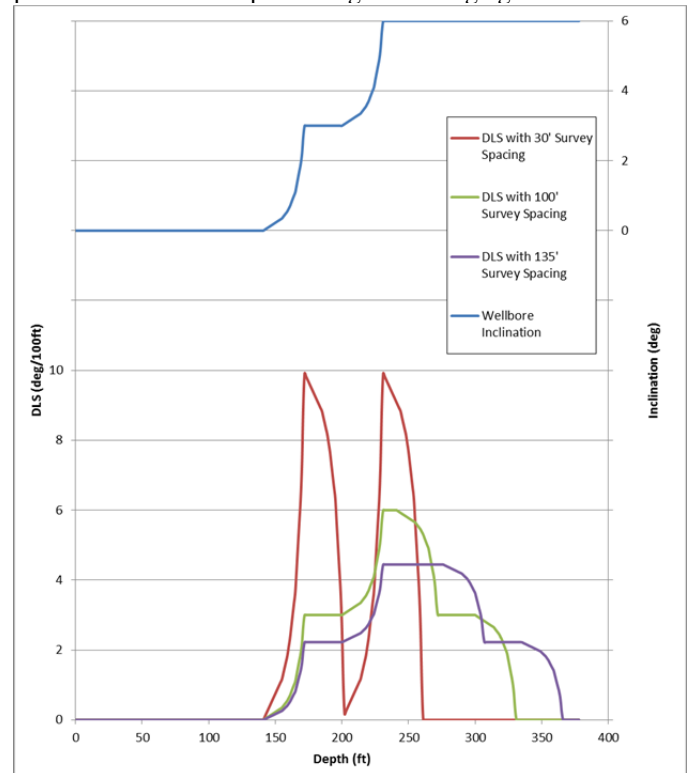


Figure 10: Calculated DLS Based on Survey Spacing and Location

However, having finished the reaming, the new survey location is a few feet different, resulting in a different measured DLS. If the dogleg is lower, the conclusion is that the reaming has reduced the tortuosity while in fact it is simply measuring a different interval of the well.

Figure 10 shows a hypothetical section of wellbore with two identical slides with increasing turn radii that add 3 degrees each. The bottom three lines show the apparent dogleg for a given survey spacing if taken at the given location. As previously noted, the survey spacing impacts the observed DLS, with the greater the spacing, typically the lower the measurement. It is worth noting that the mathematics that underpin survey accuracy and uncertainty calculations generally stipulate 100ft survey spacing (Williamson, H. 2010).

What is also relevant is the impact of moving a survey point forwards or back a few feet. Moving even 2ft can reduce DLS by apparently meaningful amounts. With 30ft spacing DLS can change by more than 2 degrees, while with a more typical spacing of 100ft or 135ft, DLS changes of 0.8 and 0.6 degrees respectively are seen.

This means that evaluating the effectiveness of reaming can be strongly impacted by the location of a follow up

survey. In the field this sometimes manifests itself as the “better” of the before and after surveys being used. This can also reinforce the perception that remedial activity can be effective. In the cases where the follow up survey is randomly better, it is seen as the effect of reaming, while when the survey is worse, it is discarded as noise.

Conclusions

The examples presented do not support reaming, hole enlarging, and/or casing as reducing DLS. They are not meant to be all inclusive, but rather typify situations where the ability to reduce DLS may be overestimated. The evidence suggests that in these cases of relatively large wellbores with large casing, the dogleg as drilled will essentially be the dogleg seen by all subsequent drill and casing strings that pass through.

This has several practical implications:

- Minimizing tortuosity while drilling is paramount if DLS is a concern for well construction as post drilling activities will likely have limited impact on tortuosity
- Reaming to reduce DLS is unlikely to be effective in large hole sizes and should be considered only if a specific discontinuity is targeted (e.g. sharp formation change)
- Casing needs to be significantly smaller than drilled hole size to effectively change DLS
- When evaluating DLS before and after an activity, it is important to try and match the survey station locations as closely as possible to provide meaningful comparisons
- Continuous MWD inclinations and 1ft gyro measurements are useful for relative DLS assessment, but can be challenging to directly compare to normal surveys without data filtering or weighting

The authors do not feel that, on the basis of the evidence presented and what is currently published, reaming is warranted as mitigation for micro-tortuosity. While the activity may benefit hole cleaning, it usually does not impact DLS and time taken to perform reaming specifically to smooth the wellbore is likely time that will not help well construction and may actually contribute to down time due to tool failures from vibrations incurred while reaming and wellbore instability from additional open hole time.

Nomenclature

<i>BHA</i>	= <i>Bottomhole assembly</i>
<i>DLS</i>	= <i>Dogleg Severity (typically deg/100ft or 30m)</i>
<i>ID</i>	= <i>Inner Diameter</i>
<i>MWD</i>	= <i>Measurement While Drilling (tool)</i>
<i>OD</i>	= <i>Outer Diameter</i>
<i>RPM</i>	= <i>Revolutions per Minute</i>
<i>RSS</i>	= <i>Rotary Steerable System(s)</i>
<i>TVD</i>	= <i>True Vertical Depth</i>

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