AADE-03-NTCE-03

Rotary Steerable in 6” hole Key to Economic Wellbores

Craig Sidwell, Jim Jares, Marcus Durant – Schlumberger, Drilling & Measurements

Abstract

A 4 ¾” tool system was introduced in 2002 which enables rotary steering in 5 ¾” to 6 ½” hole diameters. This paper will discuss well design considerations to take advantage of this technology in mature field exploitation through more aggressive trajectories on development wells and cost effective cased hole sidetracks.

Sufficient experience has been gained worldwide in a variety of reservoirs and conditions to substantiate tool reliability and show the full range of tool capabilities. Demonstrated wellbore benefits include complex 3D well trajectories, the reduction of drilling time, cost savings in downsizing from 8 ½” hole and more horizontal reach than was previously possible compared to conventional directional drilling. This rotary steerable service has also been combined with LWD tools to give effective geosteering capabilities resulting in increased net pay in high angle and horizontal reservoir sections.

Introduction

Rotary steerable drilling systems provided a step change[1] in directional drilling performance both by extending wellbore reach and by reducing drill time in hole sizes from 8 ½” to 18 ¼”. Implementation of rotary steerable systems has been greatest in high cost environments and especially in deepwater directional and horizontal wells. Rotary steerable drilling is now becoming more accepted and economically viable in lower cost drilling environments. With the introduction of the smaller diameter 4 ¾” tools, the advantages of rotary steerable tools can now be applied to 6” hole sizes. Please note that 6” hole in this paper is used in a general sense to refer to the common range of hole sizes from 5 ¾” to 6 ½” suitable for drilling below 7” or 7 5/8” casing.

This paper will examine where and how 4 ¾” rotary steerable systems provide improvement over conventional directional drilling. The economic impact of these improvements will be discussed and suggestions made regarding implications to well design with 6” hole sections.

Limit of Conventional Directional Drilling in 6” hole

Prior to rotary steerable systems, directional assemblies generally used positive displacement motors to deviate the well trajectory by a combination of slide and rotary drilling. The disadvantage of sliding is a drop in overall penetration rate due to time required to orient and reduced instantaneous ROP compared to rotary drilling. Using motors, there is often a reluctance to drill 6” directional hole more than 1500 - 3000 ft horizontal displacement due to problems sliding and increased potential of stuck pipe.

One limitation to horizontal reach in 6” hole is helical buckling of drill pipe which leads to friction lock up when trying to slide. Figure 1 shows the axial force in 3 ½” drill pipe while rotating in a sample well. A weight of 6,000 lb is effectively transmitted to the bit without buckling of the drill pipe. Figure 2 shows the same case without pipe rotation during a slide with a motor. There is sinusoidal buckling occurring mainly in the upper half of the drill sting. In this condition it is still possible to slide although the directional driller will find it harder to keep a constant weight on bit. A more extreme case is shown in figures 3 and 4 for a theoretical new well at 20,000 ft MD using 3 ½” drill pipe in the 6” hole section. Figure 3 shows that there is no trouble rotating with 6,000 lb WOB but when attempting to slide in Figure 4, the drill string undergoes both helical and sinusoidal bucking. This helical buckling adds extra friction that in practice inhibits further sliding. Although there are advanced directional drilling techniques which can result in limited pipe movement and weight to the bit, the general result is that progress rate dramatically slows to the point where slide drilling is no longer economic.

Drill pipe buckling analysis is further complicated by the mechanical impediment of weight transfer due to hanging up on ledges while sliding. Weight transfer is also affected by changes in mud properties and cuttings characteristics which change the overall friction factor. Improper hole cleaning while sliding can also lead to an increased wellbore friction factor.

Reach improvements with Rotary Drilling

Problems with inability to slide are solved by rotating the pipe enabling effective weight transfer to the bit when drilling. This normally results in 6" borehole that is drilled farther and faster. A faster hole can result in direct cost savings. Drilling 6" hole farther can result in access to more reserves from a single well bore, less wells to exploit a reservoir and higher flow rate of the completions.

Another drawback to slide drilling is that it tends to create higher tortuosity than rotary drilling. This increase in tortuosity is thought to be a result of the multiple slide/rotate sequences with each slide sequence producing a localized micro-dogleg higher than the overall average. This in turn increases both drag and torque. With rotary drilled wells, dogleg severity is more constant throughout the length of each stand. Another effect of the micro-doglegs from sliding is that a horizontal drainhole will not be perfectly horizontal but have elevation changes at each slide sequence. Rotary steerable drilling can drill a "flatter" horizontal profile.

Rotating also makes it less likely to get the drill string stuck than slide drilling. First, because the pipe is moving, there is a reduced risk of differential sticking compared to even a single slide sequence. Secondly, hole cleaning is greatly enhanced with drill pipe rotation due to better cuttings transport. Cuttings beds on the low side of the hole are reduced in higher inclination wells resulting in less chance of packoff. Hole cleaning benefits increase with the rpm of drill string although the relationship is not linear.

Non-steerable rotary assemblies

Non-steerable rotary assemblies are occasionally used for directional drilling in tangent sections. They use stabilizer placement and WOB variation to manipulate inclination. The disadvantage is that frequent BHA changes are required if stabilizer geometry was not exactly right or if the formation type changes. Control of azimuth is not possible except by taking advantage of natural bit walk. Control of inclination can be enhanced by using variable gauge stabilizers (able to change gauge from surface) but BHA tendency is still limited just to build, neutral or drop responses. Additional frustration is experienced in the 6" hole size due the relative flexibility of 4 ¾" drill collars making directional response less predictable.

Rotary Steerable function

Rotary steerable systems enable control of both inclination and azimuth while rotating. Several brands of RSS tools are on the market with varying mechanisms to effect steering.

The Schlumberger 4 ¾" tool introduced in 2002 for 6" hole sizes is called PowerDrive Xtra 475. It is a scaled down version of the successful PowerDrive rotary steerable system proven over the last few years. A side force is applied by sequentially pushing pads against the opposite side of the hole to desired bit build. Changes to steering are given from surface by a series of changes in pump flow rate. Both bit direction and pushing force from the pads can be changed with surface commands. Changes to steering are made while rotating thus the drill string needs to be static only on connections. Confirmation of tool commands can be sent from the tool to surface via an optional link with the MWD system.

Sensors in the tool transmit inclination and azimuth from 7.9 ft behind the bit which aid in keeping to planned well profile. In addition, real time drilling mechanics information from accelerometers in the tool can be transmitted to give a better understanding of the near bit drilling environment.

The Schlumberger tool has a 4 ¾" body and is designed for use in 5 ¾' to 6 ½" hole sizes by varying the Bias Unit size. Larger hole size may be obtained by positioning an under reamer higher in the BHA. A North Sea run in August 2002 used a 7" under reamer positioned 73' above a 6" PDC bit to successfully rotary steer a 1754 ft section in 28.1 hours at planned inclinations from 75° to 86°. Bicenter bits are not suitable for use with the existing "push the bit" 4 ¾" tool.

Build rates with the Schlumberger 4 ¾" rotary steerable tool have been observed up to 10°/100 ft as determined by continuous inclination measurement. Rating of current design is 8-10°/100ft DLS build rate but the tool can pass through a 15°/100 ft curve while rotating and 30°/100 ft while tripping.

Rotary steerable systems can also be combined with straight motors to provide a higher rpm at the bit. The steering function comes only from the rotary steerable tool. It was envisioned that use of rotary steerable systems in future land drilling would require combination with straight motors for economic drilling of softer, rpm sensitive formations. Actual results in recent wells have shown tremendous improvements in ROP performance without the need for a mud motor.

Geosteering adds net pay

The ability to geosteer in 6" hole was not available with previous rotary BHAs. Rotary steerable systems now allow the drilling benefits of rotation to be combined with realtime LWD formation measurements to provide optimum wellbore placement. Since rotary drilling can reach farther than slide drilling, an increased area can be covered by geosteering techniques.

Geosteering is used in many wells to reduce the uncertainty for both directional and horizontal wells. When combined with 4 ¾" rotary steerable systems, a synergistic effect should be more net pay in each 6" borehole pay section.

Sidetrack Feasibility
Sidetracking from existing wells will be the major strategy in maximizing impact of rotary steerable technology in mature fields Rotary steerable 4 ¾” tools are suitable for sidetracking from 7” or 7 5/8” casing strings which represents a significant number of production casings. Schlumberger has current experience of 12 cased hole sidetracks out of a milled casing window using the 4 ¾” tool system as of January 2003.

Current experience indicates that when sidetracking from a whipstock, particular attention must be paid to the depth of the hole milled outside the casing and to make sure the mill completely exits the casing to correctly form the window. There should be ideally be 15 ft or more rat hole from the mill run to place the rotary steerable control pads below the casing window.

Wellbore design recommendations
Economic impact of 6” hole rotary steerable technology will come not only from lowering drilling costs, but also perhaps more significantly, from reaching additional hydrocarbon reserves through aggressive design of wellbores. Value can be created by rotary steerable systems in two phases of field development. First, new wells can be programmed for further reach and more accurate placement. Secondly, effective sidetracks from existing wellbores can extend the economic life of a field.

Rotary steerable systems remove the well design constraint of limited reach due to slide requirements of the bent housing motor directional assemblies. The limit to well horizontal reach, depending on well, will then become some other parameter such as pump pressure limitation, 3 ½” drill pipe strength or limits to surface torque from the drilling rig. In most fields, switching to rotary steerable for 6” hole size will provide significant increase to the horizontal reach.

To take advantage of rotary steerable, wells can be designed for farther horizontal reach, for more complex 3D well trajectories and to maximize use of geosteering as dictated by the reservoir geology. Additional benefit may come from downsizing wellbores to drill the pay zone with 6” rather than 8 ½” hole sizes. As increasing reliability of 6” wellbore is demonstrated, well designers can reduce contingency and instead plan for 6” final hole.

Drilling longer wells from a centralized land pad or an offshore platform is usually a strategic requirement. Economic drivers are environmental land use, a reduction in surface facility costs and an overall general reduction in the number of pads or wells required for development drilling. For example, horizontal reach on well design is extended from 4000 ft horizontal to 7000 ft, the area that can be covered drilling from a multi-well location increases by a factor of three.

Rotary steerable tools can also improve horizontal wells that have a shorter radius build section. The build section with rates of 12° to 30°/100 ft is first drilled with motor assemblies until the tangent or horizontal interval is reached. Then a rotary steerable BHA is run to drill the main horizontal section. This concept is being applied in USA land wells.

Rotary steerable systems can also be used to effectively keep a well vertical. This opens up possibility to sidetrack, gain horizontal offset and then bring the wellbore vertical though the desired pay zone. Vertical completion is advantageous in lower permeability when fracture stimulation is required.

The 4 ¾” tool size rotary steerable systems are suitable to use inside most 7” and 7 5/8” casing weights. As such, there is a large window of opportunity for use in land drilling and continental shelf wells, and not just for the high day rate deepwater wells.

More efficient rotary steerable drilling will not only impact the drilling team but also the completion engineer, production engineer, asset managers and reservoir management team. The advantages rotary steerable systems provide fall into the four main categories of direct cost savings, reduced drilling risk, more lateral access to reserves and a smoother wellbore for better completion and workover operations.

Direct savings to drilling costs
Drilling time and cost will be reduced because the time to orient and slide is eliminated. The higher the daily rig and associated equipment cost, the more cost saving rotary steerable systems in 6” hole will bring.

Depending on formation and BHA combination, there are quite often improvements in instantaneous ROP. An example of this in harder formations, where ROP is strongly sensitive to WOB, a 4 ¾” or 5” mud motor may stall at high WOB with a PDC bit causing WOB to be limited. There have been cases of ROP increasing a factor of 2 or 3 times by using a rotary system in 6” hole to provide a higher WOB in harder formations.

Drilling costs can also be decreased by reducing final hole size from 8 ½” to 6” in certain well design situations.

Reduced risk while drilling
As previously discussed, rotary steerable systems have less problems caused by poor hole cleaning and there is a reduced risk of differential sticking. This is particularly

important for reducing risk in depleted reservoirs or where higher mud weight is required to control wellbore stability in upper zones.

More reserves accessed by a wellbore

The basic premise is that we can drill a wellbore farther in horizontal displacement by using rotary steerable systems. Where reservoir depletion will benefit from longer horizontal reach, wellbores can be designed to expose more pay zone for better drainage or expose isolated pockets such as "attic oil" or other complicated structural traps.

The other avenue to access more reserves comes from extending the reach of geosteering by combining it with rotary steerable systems. As a result, an operator can drill more complicated 3D profiles potentially linking up multiple smaller sections of pay.

Better shape wellbore for completions

Completion and production engineers will find benefit in the well operations after drilling because the sections drilled with rotary steerable systems are smoother. There should be less micro doglegs than similar wells drilled with bent housing motor assemblies. Thus, when running sand control screens there is a greater certainty of getting screens to TD. Smoother wellbore will also reduce running forces for coiled tubing during workover or remedial stimulation and is especially desirable in deep directional wells.

One other production aspect is that rotary steerable can drill a flatter profile for horizontal wells giving less dips or low spots which accumulate liquids and act as down hole chokes to gas flow.

Conclusions

Rotary steerable drilling systems for 6" hole were commercially introduced in 2002 and have many advantages over conventional slide drilling. Well economics will benefit by direct savings to drilling cost, reduced risk while drilling 6" hole, the ability to access more reserves from a single wellbore and from better wellbore geometry for the completion. Benefits apply to both new well construction and to sidetracks from existing wellbores.

Asset and reservoir management teams now have increased latitude in well placement particularly in mature fields where precise well placement with geosteering, longer well reach in 6" hole size and use of existing 7" and 7 5/8" wellbores for side tracks is required to create the maximum value. Well designers should be aware of 4 ¾" rotary steerable system function for 6" hole and consider more aggressive wellbore trajectories as viable solutions for drilling optimization.

Nomenclature

3D = Three dimensional
BHA = bottomhole assembly
DLS = Dog leg severity
LWD = Logging while drilling
MWD = Measurement while drilling
MD = Measured depth
PDC = Polycrystalline diamond compact
ROP = drilling rate of penetration
RSS = Rotary steerable systems
rpm = revolutions per minute
TD=total depth
TVD=true vertical depth
WOB = weight on bit

References

1. Charlie Pratten, "Rotary Steerable Systems in the Gulf of Mexico – A Step Change in Drilling Performace", AADE Paper number AADE 01-NC-HO-22, presented at the AADE 2001National Drilling Conference, Houston, Texas, March 27-29, 2001.

Figure One – Pipe Axial force while Rotating at 15,000 ft in 6 1/8" hole

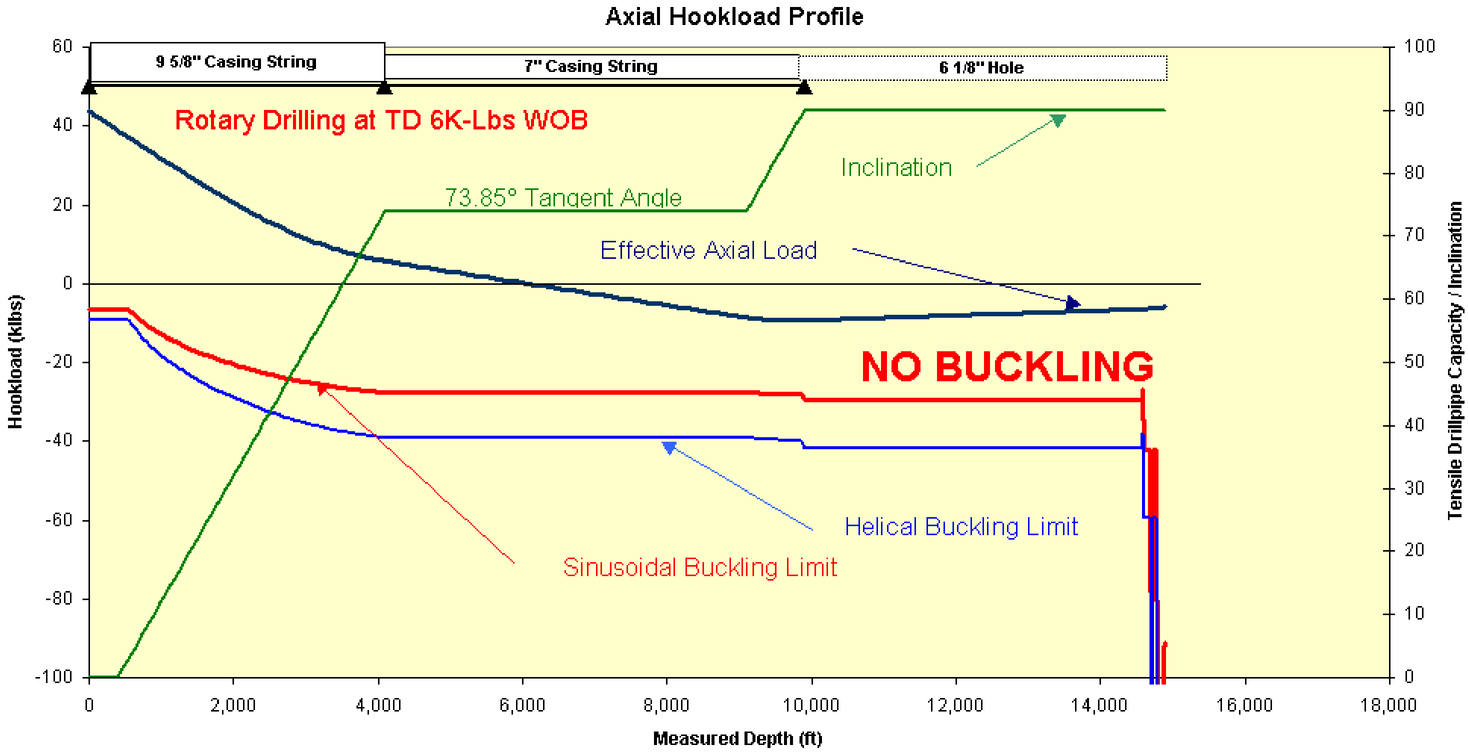

Figure Two - Axial drill pipe force while Sliding at 15,000 ft in 6 ½" hole. – Example Sinusoidal buckling

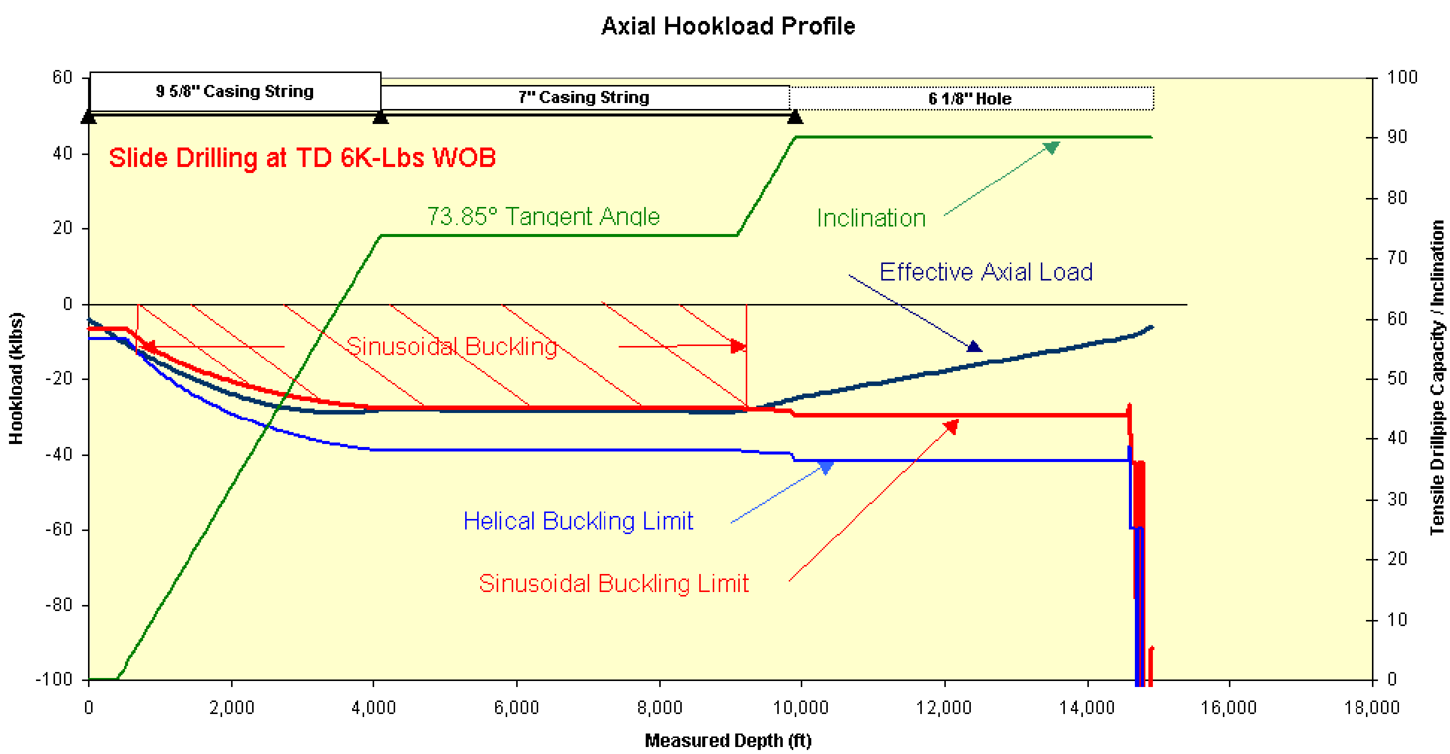

Figure 3 – Axial drill pipe force while Rotating at 20,000 ft in 6" hole

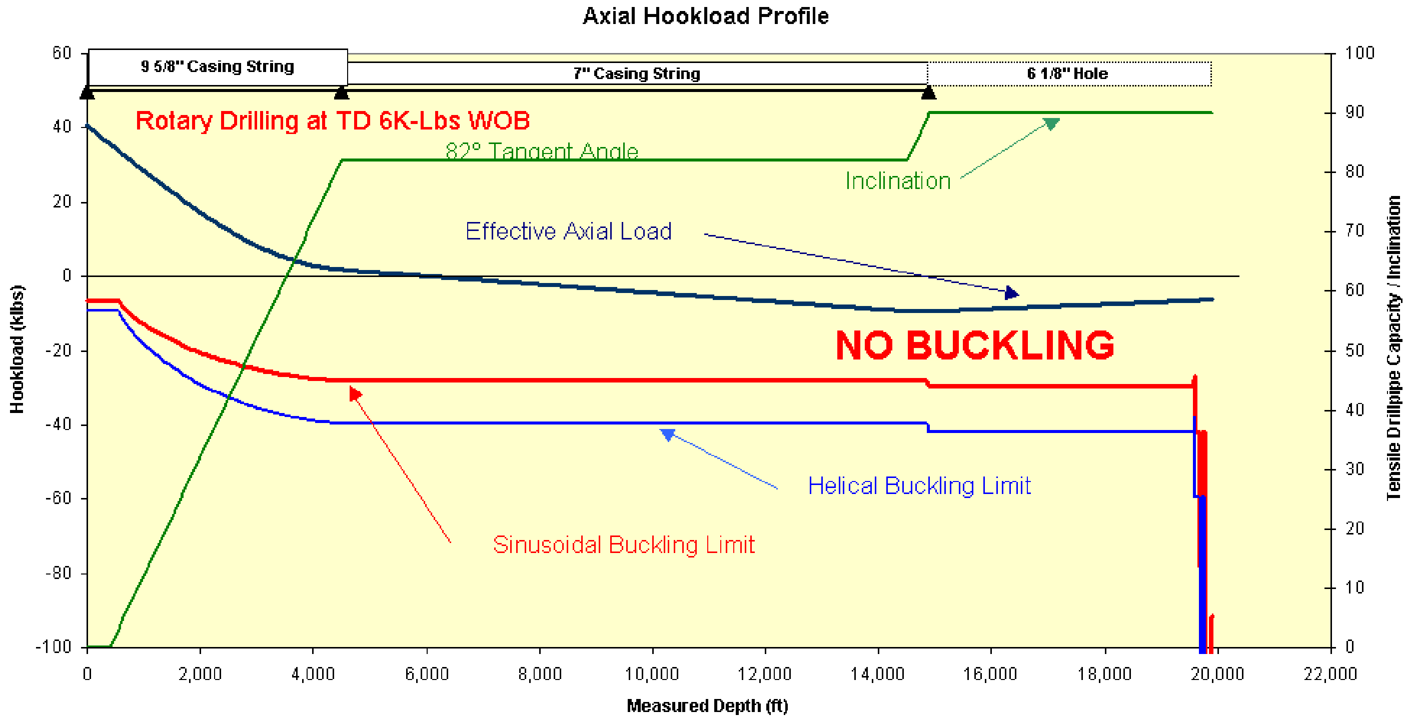

Figure 4 – Axial drill pipe force while Sliding at 20,000 ft in 6" hole – Helical and Sinusoidal Buckling example