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A Conventional Steering Revolution: Use of a Rotational Steering Tool (RST) to Extend the Capabilities of the Conventional Steerable Bottom Hole Assembly

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Abstract

Despite capital constraints and rising service costs, operators and service providers in the U.S. drilling market continue to push the boundaries of well lengths, trajectories, and cycle times. Remarkably, much of this progress has been achieved using conventional technologies that have remained largely unchanged for over a decade. This raises a critical question: How much more can performance be improved before the only viable path forward involves increased reliance on downhole electronics and higher costs?

This paper introduces a Rotational Steering Tool (RST), an innovative approach that enhances conventional steerable bottom hole assembly (BHA) performance by bridging the gap between fixed-string assemblies and rotary steerable systems. The RST provides steering orientation, friction reduction, and improved weight transfer while maintaining continuous drill string rotation.

In collaboration, Bison Oil & Gas IV, LLC and Drilling Tools International have successfully implemented the RST in the Denver-Julesburg (DJ) Basin, achieving significant performance improvements. This paper details the tool's development, its implementation journey with an early adopter, and the resulting drilling performance gains across multiple stages of well construction.

Background

In today's drilling environment, operators face a choice between two distinct approaches: advanced Rotary Steerable Systems-based BHAs and conventional BHAs. RSS systems offer enhanced steering precision and real-time control but can pose challenges such as higher costs, availability constraints, and the need for specialized expertise, complicating risk management. Conversely, conventional BHAs, known for their robustness, can suffer from steering performance degradation particularly in extended laterals primarily due to well friction and the operational adjustments required to mitigate its impact. This section provides a brief overview of these challenges, setting the stage for a novel approach that reimagines the deployment methods of conventional BHA technology to mitigate these issues and serves as a third option for operators when evaluating their approach to lateral drilling.

RSS Systems

The RSS systems being deployed today are impressive technical achievements capable of delivering precise well placement in nearly all drilling environments. However, implementing RSS-based BHAs can bring significant challenges that span economic, logistical, and operational realms. From a value standpoint, several key factors must be considered to ensure these technologies deliver intended benefits to a drilling program.

Economics

RSS technologies utilize numerous integrated sensors and precise steering mechanisms that are costly to build and maintain. Naturally, these factors translate into higher operating costs which Operators must ensure are offset by the enhanced performance and time savings.

Supply and Vendor Constraints

A critical challenge lies in securing the necessary tools and expertise from preferred vendors. Availability can be limited, and not all providers may be able to supply tools for specific applications and hole sizes. Compounding this issue, existing personnel might lack the specialized training needed to effectively operate and manage RSS systems. This dual dependency on vendor-supplied tools and expert operational support can introduce management of change (MOC) challenges and elevate risk, particularly when considering RSS systems for well specific applications or as a secondary lateral BHA option to finish deeper laterals

Risk Management

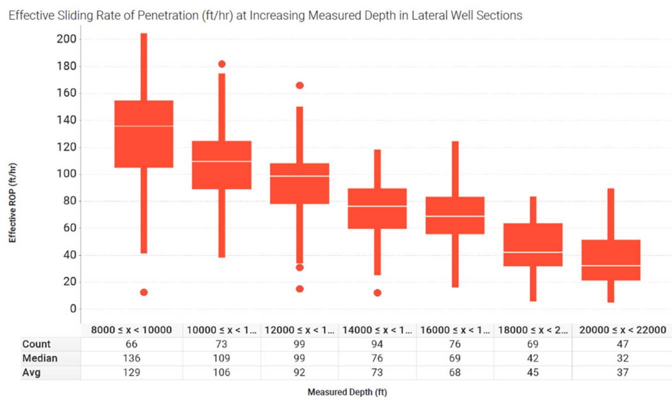
Beyond operating cost and supply issues, the overall risk profile of RSS deployments must be carefully managed. The potential for tool damages and losses as operational complexity increases with well depth should always be a consideration. While the initial risk assessments justifying the use of RSS systems may be favorable, they must also adequately account for the skewed risk probabilities and escalating costs deeper in the well. In instances where multiple BHAs are required to finish a well the risk/reward balance must remain favorable when opting to utilize these technologies, which may not always be the case for shorter runs in the deepest portions of some wells.

Conventional BHAs

Conventional BHAs have long been valued for their robust and proven performance. However, as drilling conditions become increasingly complex, several interrelated challenges have emerged that affect their overall efficiency and consistency.

Performance Degradation Due to Friction Effects

Extended lateral drilling exacerbates friction effects within the wellbore, leading to notable performance degradation in conventional BHAs (Figure 1).



	8000 ≤ x < 10000	10000 ≤ x < 1...	12000 ≤ x < 1...	14000 ≤ x < 1...	16000 ≤ x < 1...	18000 ≤ x < 2...	20000 ≤ x < 22000
Count	66	73	99	94	76	69	47
Median	136	109	99	76	69	42	32
Avg	129	106	92	73	68	45	37

Figure 1 Effective Steering ROP's aggregated over 2000 ft lateral intervals showing the decreasing steering performance of conventional BHAs in deeper portions of the lateral sections

As friction increases, performance while slide drilling to maintain wellbore trajectory diminishes, potentially resulting well placement challenges and cycle time increases. This friction-induced degradation is a critical factor that operators must manage, particularly in longer lateral sections where the cumulative impact is most pronounced.

Friction Reduction

In conventional drilling operations, surface oscillation systems (SOS) and friction reduction tools (FRT) are commonly employed to mitigate friction challenges, though their integration can add complexity and operating costs.

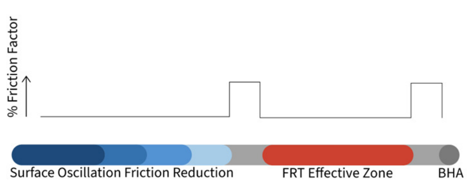


Figure 2, Simplified SOS and FRT friction profile illustration where SOS and FRT effectively used to minimize friction (for more detail, see Mahjoub et al. 2022)

SOSs leverage top drive controls to oscillate the drill pipe at varying speeds and distances, overcoming the static friction resisting pipe rotation along the drill string. This oscillatory action reduces the effective length of pipe subject to axial friction, enabling smoother pipe translation along the wellbore and improving the ability to orientate the bend housing on a conventional BHA. While these systems offer an effective, low-cost friction reduction solution, their performance diminishes in longer lateral sections as physical and operational limits are reached as seen in Figure 1.

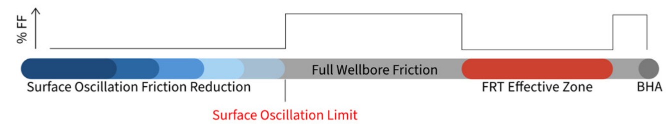


Figure 3, SOS and FRT friction profile. As well length increases and SOS reach effective limits the portion of the drillstring experiencing the full wellbore friction increases with each foot drilled

In cases where SOS alone cannot provide sufficient friction reduction along the drillstring or when additional steering performance is required, friction reduction tools (FRTs) may be integrated into the system. These tools harness energy from the drilling fluid to create targeted mechanical agitation along specific intervals of the drillstring, thereby further reducing wellbore friction. However, their use introduces financial and operational costs. Because FRTs draw energy from the fluid system, employing them, especially in multiples, can significantly increase pump pressure. This, in turn, may necessitate reductions in the total flow rate toward the end of lateral sections, resulting in diminished power generation from drilling motors and potentially causing issues with MWD telemetry.

Skill Dependence

Effective steering with conventional bottom hole assemblies (BHAs) requires precise control of multiple drilling parameters. Balancing rate of penetration (ROP) while slide drilling and maintaining tool face orientation necessitate continuous adjustments to top drive orientation and autodriller (AD) settings.

Figure 3 provides a simplified view of friction reduction achieved using a SOS, suggesting a consistent relationship between oscillation and wellbore friction reduction. In reality, the extent of friction reduction depends on dynamic factors such as string loading, autodriller parameters, and the manner or sequencing in which oscillation settings are adjusted. These complexities make steering with a conventional BHA highly dependent on personnel expertise, introducing variability into the performance of the operation.

Operational Challenges

Slide drilling with conventional BHAs presents mechanical and operational challenges, due to pipe buckling, squat, and pickup height uncertainties. Friction exacerbates these issues, increasing directional non-productive time (NPT) and the risk of tool damage during transitions between rotary and slide drilling (Fonseca, et al. 2023).

Higher wellbore friction in slide drilling leads to pipe buckling, increasing side loading and string shortening, requiring high rotary torque to restore rotation. Depth uncertainty, combined with increased rotational energy, has been identified as a leading cause of downhole tool failures. Additionally, positional uncertainty due to pipe stretch when hoisting the BHA off-bottom often results in excessive pickup heights to ensure bit disengagement, further increasing directional NPT and risks such as whirl and torsional oscillations while rotating the BHA with limited formation engagement (Marland, et al. 2022)

New Approach to Lateral Well Challenges

Operators today face a choice between rotary steerable systems and conventional bottom hole assemblies, each with distinct challenges in extended lateral wells. While rotary steerable systems offer precise well placement, they come with high costs, supply constraints, and reliance on specialized expertise. Furthermore, as laterals extend deeper, the risk of tool failures and escalating costs increases, making effective risk management critical.

Conventional BHAs, while cost-effective and widely used, struggle with friction-induced performance degradation and require complex friction reduction strategies such as surface oscillation systems and friction reduction tools. These methods can help mitigate some of the steering challenges but introduce the operational constraints previously discussed all while adding more reliance on the skill and experience of personnel leading to performance variability.

The need to address these risks and limitations has led to the development of a new category of steerable drilling assembly that provides the friction abated reach of RSS while utilizing existing, time-tested conventional BHA components. By bridging the gaps between rotary steerable systems and traditional methods, this innovation provides a cost-effective and efficient alternative, reducing performance variability and improving drilling outcomes in extended laterals.

Rotational Steering Tool Introduction

The Rotational Steering Tool (RST) enables wellbore steering corrections while maintaining continuous drill string rotation at the surface, improving directional control and performance in conventional bent motor assemblies. By harnessing rotational energy from the drill string, the RST transmits torque across decoupled sections within the tool with enough force to counteract motor reactive torque and the rotational drag of components below.

Functioning as a progressive cavity pump, the RST harnesses torque generated at the bit/rock interface to induce rotation and generate pressure at the rotor/stator interface, effectively transferring torque. When a steering correction is required, the rig operator reduces right-hand surface rotational speed until it matches the speed at which bit torque drives the lower section of the pump in the left-hand direction, bringing the relative rotation of the bottom hole assembly to zero. This process is similar to walking the wrong way on a motorized walkway at an airport. If you walk at the same speed as the belt, you remain stationary relative to the terminal. Similarly, by balancing these rotational forces, the RST enables precise steering corrections while preserving friction reduction from full drill string rotation.

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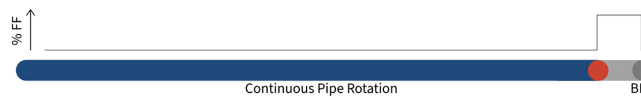

Figure 4, RST friction profile compared to Figures 2 and 3 from earlier. The friction is a known and consistent amount between the tool and the bit

Once the steering correction is complete, the rig operator simply increases surface RPM to reestablish the desired right-hand BHA rotation and resume normal drilling operations. Using the airport analogy again, after temporarily matching the walkway's motion to remain stationary, increasing your walking speed allows you to move forward again. Similarly, as surface RPM increases, the BHA returns to rotating, enabling continuous drilling. The result is a step down in RPM between the drill string above the RST and the BHA below—just as the rate at which you move forward on the walkway is the difference between your walking speed and the speed of the moving belt.

RST Overview

The tool consists of four sub-assemblies: a bearing pack, transmission, pump, and TCS. (Figure 10) The pump section features a rotor and stator. The RST is fully bored, generating only a minor pressure drop—roughly equivalent to the pressure drop of the tool's internal ID reduction.

Tool Placement

The RST is simply incorporated into the BHA, with a recommended weight below the tool of approximately 20 klb. To achieve this, HWDP is recommended, typically positioning the RST 200 ft to 400 ft behind the bit. Earlier tool iterations placed the RST directly above the MWD tool for closer proximity to the bit; however, this resulted in unmanageable input reactions for toolface control. Adding weight below the tool acts as an inertial damper, stabilizing and dampening reactive torque generated by the PDM. This reduced the number and degree of adjustments needed to maintain tool face while sliding.

Tool Execution

Transitioning from rotary to steering mode is significantly simplified compared to traditional methods. While drilling, ROP is slightly reduced, and WOB/DP drill-off is initiated. RPM is then lowered to the target value, ensuring consistent weight transfer in this process is critical. Once a consistent toolface is established, differential pressure can be increased to turn the BHA left, or RPM can be gradually raised to induce movement. This process simplifies the inputs needed to execute a slide, as RPM and consistent slack off.

To end a steering interval, ensure that weight is not stacking out, then gradually increase RPM. This portion can follow any predetermined Slide-to-Rotate guidelines, such as reducing RPM until the bend of the PDM is fully buried in newly drilled hole.

The process of transitioning into and out of steering intervals without disengaging the bit can be a divisive topic. Given the function of the tool to reduce the friction while steering and the manner in which it decouples the BHA, this process has not been seen to result in high torsional oscillations or shocks. RST was run with two high frequency sensors positioned on opposite ends of the tool. One on the input shaft of which rotates at drill string speed and the other attached to the bottom sub which rotates at BHA RPM. An example of rotating to slide back to rotary is seen in (Figure 11)

Early Adoption

Bison IV Operating identified a use case for the RST to reach TD in a single BHA, eliminating the need for a trip to pick up an FRT and increasing sliding efficiency deeper in the lateral section. Initial discussions began in Q4 2023, but at the time, DTI was uncertain whether inventory levels could keep pace with Bison IV Operating's drilling program. By late Q1 2024, after evaluating and expanding capacity, DTI re-engaged with Bison IV Operating to move forward with field implementation.

At the start of the project, Bison IV Operating's average well delivery time from drill-out to TD was 5.5 days (Figure 5). The sample set utilized typically slowed down towards the end of the well dealing with typical sliding degradation towards the end of the wells.

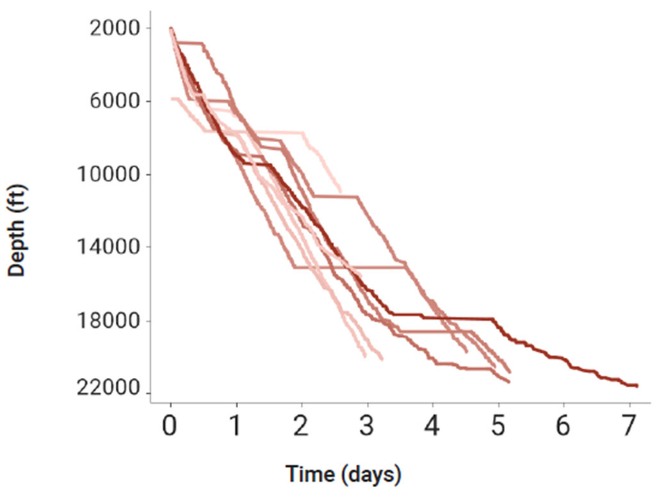

Figure 5 – Days vs Depth for Offset Wells (8) prior to implementation of RST

With the initial runs focusing exclusively on the lateral, where known sliding issues could be corrected with this technology the RST had not previously been used to drill vertically, a step-out, or curve section. The BHA was short-tripped after the curve to install the RST, following the same operational approach typically used for an FRT pickup. The first two wells confirmed that the tool significantly improved sliding efficiency in the lateral, achieving the desired performance gains when compared to conventional offsets (Figure 6). As the BHA went further into the lateral there was notably less drop in ROP compared to typical conventional BHAs performed. The drop is much less pronounced getting further out into the laterals.

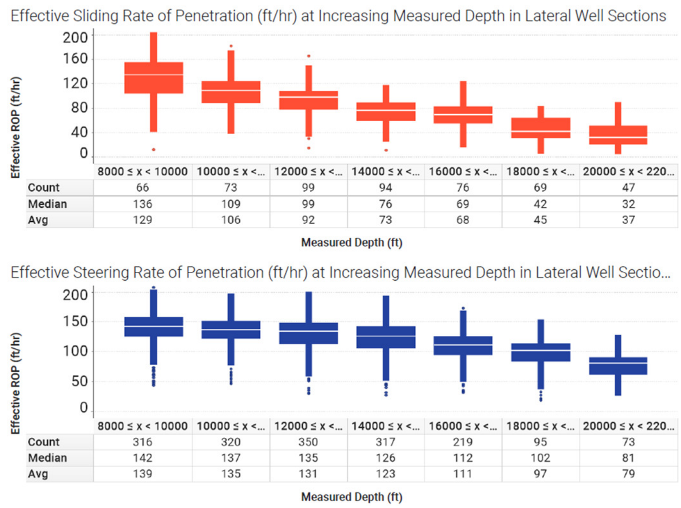

Figure 6 - Effective sliding ROPs over 2000ft intervals through the lateral section of conventional vs RST sample wells. Red is conventional blue is RST.

The next objective was to drill the entire well from casing drill-out to TD using the RST without tripping. One early challenge in the trials was ensuring downhole RPMs remained within target parameters. To address this, the team implemented collar RPM monitoring from the MWD tool at regular intervals to verify that downhole RPM limits were not exceeded. This approach proved effective, allowing for real-time performance optimization as differential pressure increased. Adjusting surface RPM accordingly ensured the BHA maintained the desired rotational speed throughout the run.

Through consistent RST implementation wells were drilled at a steady rate with little drop off towards the end of the well from sliding degradation, less transitions and other benefits that the RST provides. (Figure 7)

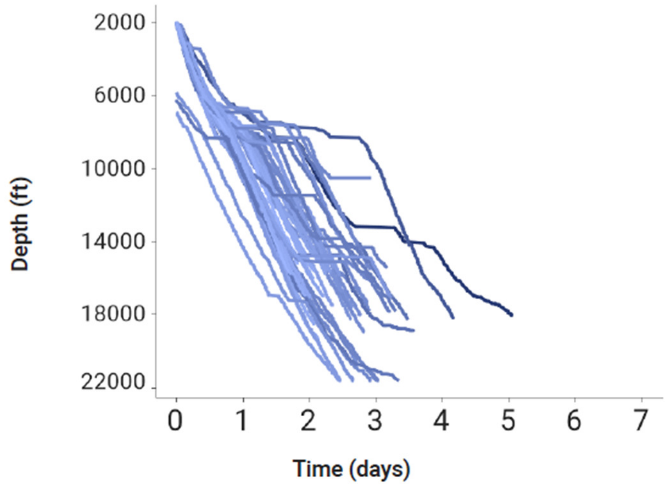

Figure 7 – Days vs Depth for 43 Wells Drilled utilizing the RST

Another benefit observed which helped improve cycle time was a reduction in unplanned trips in the lateral (Figure 8). Over the course of 43 wells utilizing the RST, the total tripping time for unplanned trips in the lateral was equivalent to that of the 8-well sample set. This was attributed to improved tool reliability, potentially due to decoupling the BHA from the drill string, consistent slide execution, elimination of the FRT, and smoother slide to rotate and vice versa transitions.

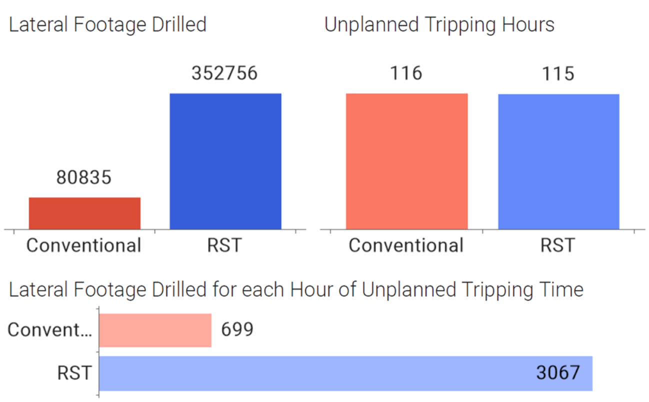

Figure 8 – Well sample set aggregated into lateral footage drilled, Unplanned trip hours and lateral footage drilled per unplanned tripping hour.

Conclusions

Bison Oil & Gas IV, LLC's willingness to be the first adopter of the RST in the DJ Basin has established them as a leader in drilling innovation. Their early investment in this technology not only improved operational efficiency but also set a new performance benchmark for the region. As a result, other operators have taken note and begun incorporating the RST to replicate Bison IV Operating’s success, demonstrating the tool’s effectiveness and industry-wide value. This widespread adoption emphasizes Bison IV Operating’s reputation as a forward-thinking company that embraces cutting-edge solutions that enhance efficiency and performance

With consistent tool application and a commitment to continuous improvement, the average well cycle time between drill-out to TD was reduced by two days (from 5.5 to 3.5 days, Figure 9). Most performance improvements occurred in the lateral section, with even greater gains in its second half.

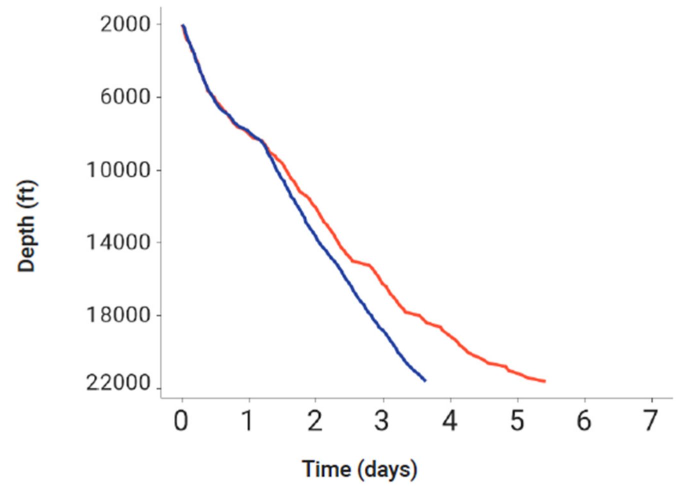

Figure 9 – Days vs Depth data aggregated by depth in 100 ft intervals from sample wells for conventional and RST BHAs. RST is blue, conventional is red.

As the industry progresses, the application of innovative downhole tools like the RST will be crucial in shaping the next generation of drilling technology. By pushing the limits of conventional BHAs and extending their capabilities, operators can achieve greater efficiency, lower costs, unlocking new opportunities for complex well designs.

Acknowledgments

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Nomenclature

BHA = Bottom Hole Assembly
DD = Directional Drillers
DJ = Denver-Julesburg
DOC = Depth of Cut
DP = Differential Pressure (PSI)
DTI = Drilling Tools International

DvD = Days vs Depth
FRT = Friction Reduction Tool
PCP = Progressive Cavity Pump
PDM = Positive Displacement Motor
RPM = Rotations Per Minute
RST = Rotary Steering Tool
SOS = Surface Oscillation Systems
TCS = Torque Control Sub
TD = Total Depth
TDS = Top Drive System
WOB = Weight on Bit (Klbs)

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Additional Figures

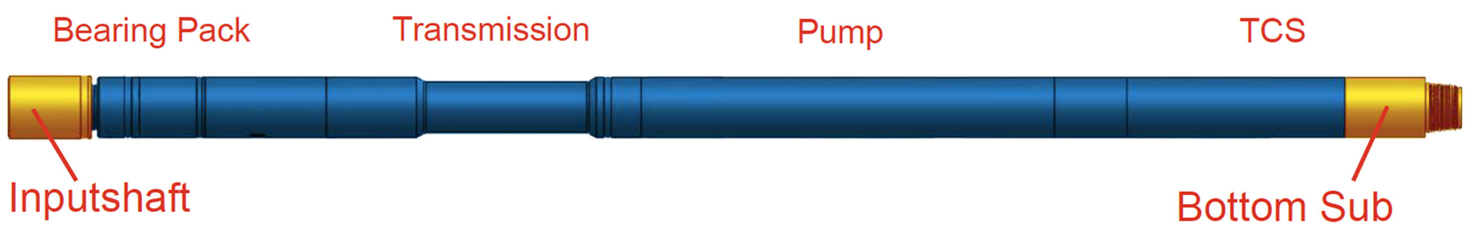

Figure 10. RST with downhole end towards the right. The tool's sub assemblies are broken up on the top. The Inputshaft & bottom sub are denoted for location of sensors.

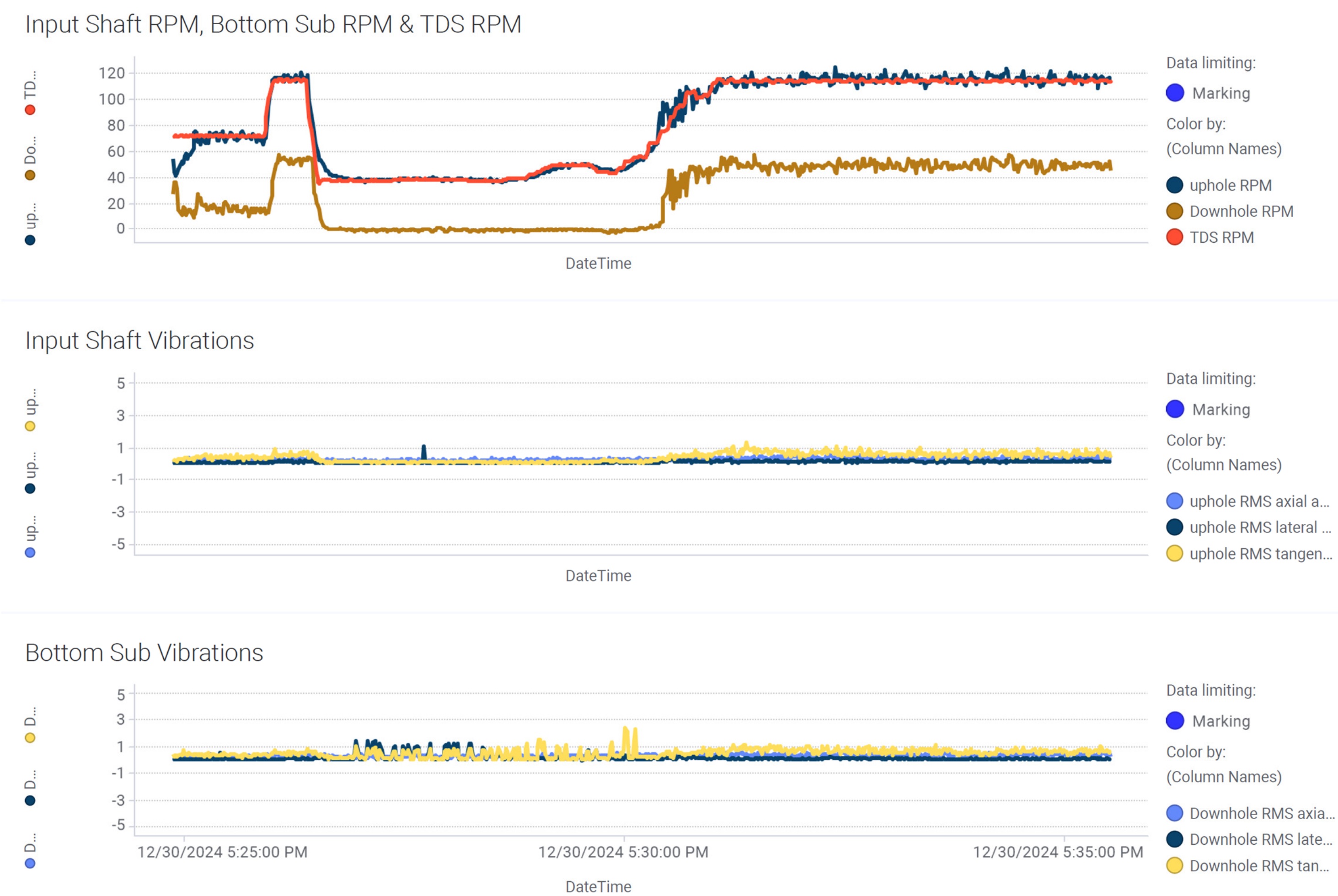

Figure 11 - 1 second senor data from rotate to slide, then back to rotary. All 3 charts are time synced together over a 12 minute interval. The first chart shows downhole RPM of the two sensors withTDS RPM matching closely to the top sensor. The other two are average vibrational data at opposite ends of the tool.