MEASURING WELLBORE FRICTION DURING WORKOVER OPERATIONS (UPDATE)

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ABSTRACT:
The workover process provides a unique opportunity to directly measure wellbore friction as the rods effectively probe out the wellbore with various lengths. Measuring this frictional effect for each length of rods is challenging as no sensor exists that can provide an accurate, high resolution, high frequency measurement during the entire workover process. A new sensing device was developed to gather load and position data during the workover process, while handling rods. The normal rig crew process was unaltered beyond the initial installation and removal of the sensor. Detailed sensor measurements are recorded for each stroke of the rig and these measurements are processed to determine the overall behavior of friction acting on each different total length of rod as they are installed, removed, or otherwise moved through the wellbore.

BACKGROUND:

Common implementations of the wave equation, as currently practiced in the analyzing of running wells, do not accurately account for mechanical friction. Any friction occurring along the rod-string during the pumping stroke ends up (erroneously) in the calculated pump card resulting in a distorted plot. In other words, the wave equation coincidentally provides a cumulative measure of friction but does not attribute that friction magnitude to a specific depth. Briefly, a sensing tool is deployed on the rod-hook of a workover rig during the process of installing or removing rods.

The data and method presented in this paper illustrates a process where the wave equation calculation is repeated for all lengths of rods throughout the workover process and thus probes out the wellbore for a measure of cumulative friction acting across all depths. This can be applied to rods as they are installed or removed. A detailed background and motivation, including a discussion of the Gibbs Conjecture and the behavior of a deep rod part, which enables this analysis, can be found in the 2021 SWPSC paper by the same title.

WORKOVER RIG PROCESS:

The production rig services the wellbore by installing or removing equipment. In particular, the workover rig handles the rod string in “stands” of rods, making it analogous to a stoking pumping unit. The analysis presented here can also be applied to tubing, continuous rods/tubing, or wireline/cable, but the focus on this paper is on stick rods as they are installed or removed. **Figure 1** shows the sensor installed in-line with the rod-hook and **Figure 2** provides a step-by-step process for the workover. The rig bears the weight of the entire rod-string and moves this rod-string through the wellbore. This dynamic weight is affected by inertia, which can be accounted for through the wave equation, and by mechanical friction, which is what we intend to measure.

SENSOR CONFIGURATION:

The sensor is comprised of a tension link load-cell that is shackled in-line with the rod hook to read direct tensile loads at the top of the rod-string. The rod hook may contain a spring for absorbing shock loads, but with sufficient loads common during the process, this spring is fully extended and mechanically engaged to the stop during key periods of interest. The blocks above also include a large shock absorbing spring that is likewise fully extended during the loaded portion of the operation. The extension of these springs can be seen on the plot in **Figure 3** and is a useful feature when identifying a fully loaded stroke.

Position measurement throughout the stroke is difficult to obtain in the chaotic workover environment. The tool utilizes several sensors to derive position without the need for an externally dependent physical length measurement. More traditional approaches such as a length measurement from the draw works cables would introduce complexities in stretch and mass transfer. A laser distance sensor would be easily compromised by wellbore fluids. In short, while several methods to obtain position are available, none are suitable for the workover environment and so a new approach was needed.

The position sensing approach selected for this application primarily include a barometric pressure sensor (altimeter), an accelerometer, and load transfer points. Altimeters are good for a coarse height measurement, but drift over time as atmospheric pressure changes. A recent improvement in this regard is to introduce a synchronized, stationary barometric pressure sensor near the rig to provide a repeated measurement from a fixed location. This pressure compensation greatly improves the absolute accuracy of the altimeter on the tool over the course of the run, making it immune to overall ambient pressure changes. Barometric pressure alone is not nearly precise enough to determine position for the purposes of the wave equation. The accuracy of a barometric pressure sensor is only about 6 inches and is somewhat noisy at the desired sample rate but provides a very good general height measurement at any point in time.

A high precision accelerometer is included to supplement the altimeter readings. To determine position from acceleration, the accelerometer readings are integrated to velocity and again to position. This double integration process introduces small errors that accumulate over time. Combining the height derived from barometric pressure with the computed position from the accelerometer significantly improves accuracy.

A convenient side effect of the workover process is the load transfer occurs at a fixed position (the rod-table/wellhead), and the blocks are at an easily identified fixed distance from that point. This distance is positively determined from the known length of rods. The altimeter can identify the rough length of rod between these two heights. This can then be corrected to the exact rod length, which is typically within a few inches from the raw barometric pressure derived height. This exact distance can in turn be used to bound the accelerometer integration error accumulation.

In short, the accelerometer provides very accurate positional data, but for only short periods. The altimeter provides positional data accurate to about 6 inches, but drifts over time. Further, the localized barometric pressure is subject to wind gusts which may appear as false short-term position changes. The stationary-corrected barometric pressure compensates for overall ambient pressure drift over long periods. The accelerometer can identify these sorts of erroneous pressure changes. Likewise, the pressure can help identify periods of non-movement which are difficult to determine from an accelerometer alone. The load transfer points also provide distinct locations from which to further calibrate the combined positional derivation. The result is a surprisingly accurate position from a sensor with no external physical dependencies that would conflict with rig operations. Load and position sensing are effectively and completely self-contained.

DATA ANALYSIS:

The prototype tool generates a substantial volume of raw data which must be processed into a usable form suitable as an input to the wave equation. This section discusses some of the approaches and challenges involved in analyzing the data.

Data Processing:

In the current form, the tool primarily logs high frequency data over the entire run and is later post-processed. The tool also includes a live view via a Bluetooth connection to stream load and position data at a reduced rate. Currently this wireless connection is also used for synchronizing stationary barometric pressure readings. This wireless link could be utilized for additional purposes that may improve rig operations or to combine other remote sensor inputs.

Since the tool logs data during the whole workover process, periods of interest must be identified. These periods are when the rig is actively lifting or lowering a section of rods in the wellbore and the rod-string is actively subject to downhole mechanical friction. It is necessary to split the dataset into unique “strokes”. A stroke of the rig is defined as the point (height) where load is picked up and the following point (height) where that load is released. Future iterations of the tool may include some on-board processing or data reduction approaches, but the current implementation logs this data and is automatically post-processed into individual strokes. **Figure 4** shows a load plot over the entire run. Each spike on this graph represents a possible stroke of the rig and must be analyzed in the stroke splitting process.

Stroke Splitting:

Splitting the data into individual strokes involves observing hook load changes in combination with position changes. This process first observes whether substantial load is on the hook (through the load-cell). A change in hook load does not necessarily indicate the rig is bearing the full rod weight. In some cases, the rig may pull slight tension into the rods to stabilize the blocks for safety but may not actually pick up the rods at that point. For this stroke splitting step, a threshold load must be exceeded, and this threshold is a function of the expected rod weight for the number of rods in the well. Additionally, the position must also change while this weight is borne by the hook (and sensor) by some appreciable distance to be of practical use in the friction analysis.

The stroke splitting process observes the exact vertical position of the hook when the load is picked up, and vertical position when the load is dropped off. If these beginning and ending heights are the same, no rods were added or removed. In some cases, this may still be of interest but typically represents tension short of lifting the rod-string and should be discarded. When the start and end positions differ, this indicates rods were added or removed.

Rods run in:
If the blocks are high when the load is picked up, and then low when the load drops, this indicates a section of rods was installed, or lowered, into the wellbore. The actual height difference between these two points represents the footage of rods installed. For example, a rig handling 30ft rods as doubles, or 60ft total may encounter a worn rod box. In this case the lower rod will be installed, rod box replaced, and then the upper rod will be installed. This is evident in the data by observing the overall height at which the load was transferred on and off the sensor.

A variant of this case is when old rods are laid down. In this procedure, the rod is manually walked out by a person, as the rig operator lowers the blocks. In this case, the hook load would be that of 1 (2 or 3) rod(s) and would not trigger the stroke identifying threshold. In other words, the rods tailed out by the rig would not be identified as a valid stroke for the purposes of friction analysis or identifying items that were installed or removed from the wellbore. The loads and positions corresponding to the laid down rod would still be present in the recorded data and could be identified for other non-friction purposes like auditing which exact rod was laid down.

Rods pulled:
If the blocks are low when the load is picked up, and then high when the load is reduced, this indicates a rod section was removed from the wellbore. When a rod is in the wellbore, it can only come out through this process. The last rod, or pump is the exception where the pump is removed from the wellbore, tailed out by a rig crew member, and laid down. Aside from accounting for the equipment counts and lengths, the last few rods are likely in a vertical section and are unlikely to provide useful information regarding friction. In general, friction is additive when the rods are lifted. Understanding the direction of rod travel is also important when analyzing friction loads.

Rods moved without adding or removing sections:
The rod-string may be raised and then lowered back to the same position without adding or removing any sections, but this is easily identified from the data. If the rods have not moved substantially, this would be discarded as it may be unknown if friction was experienced. If the rods did move substantially, even if returned to the same position, this may be of interest as another friction measurement that could be performed intentionally at specific points of the workover process. In some cases, this may occur naturally as the rig crew handles the rods. For example, a crewmember or piece of equipment may not be ready, and so the rods are lowered back onto the wellhead/rod-elevator before proceeding. In general, this condition is not relied upon as part of the main analysis but could be intentionally performed to gather additional data.

Equipment Count:
As part of the Stroke Splitting analysis phase, a count of rods installed or removed is obtained. To process the data via the wave equation, this count must be cross referenced with the rod-string design to obtain the remaining rods and their properties (diameter, length, material, etc.). On subsequent strokes, this rod count is updated, and a new, or updated, rod design for the remaining rods is used for the wave equation input, for that specific stroke. This process is automated as part of the Stroke Splitting analysis and provides a unique rod-string for each stroke. Equipment counts can be used as a supplemental rod tally, but an accurate count should always be manually performed. A tubing tally could be obtained in a similar way, but there are limitations to that in the current tool configuration.

Stroke Analysis:
Once the strokes have been split into discrete windows and the correct rod configuration for each section is determined, those strokes can be further processed. The raw data includes a direct load measurement which is relatively straightforward. Position through the stroke is much more complex and deriving this from indirect sensor measurements requires careful analysis and processing. As identified in the stroke splitting phase, the individual stroke is determined to be an upstroke or downstroke by observing the barometric pressure derived height and load transfers. From this, a rod section length can be determined by rounding the pressure derived height to the nearest rod length. Typically, a rod length will be 20’, 25’, 30’, 37.5’, 50’, 60’, or 75’, and is easily identified by the barometric pressure as that sensor is accurate to about 6 inches. This can be further cross-referenced to the rod-string design if for example there are shorter pony-subs or other non-standard lengths in the rod-string.

Next, the accelerometer data is integrated to velocity and again to position over this interval. To properly integrate the accelerometer data, an initial position and velocity must be known. The initial (and final) position is known from the determined rod section length, but the initial velocity is not. The blocks are traveling at some speed when the load is picked up. Interestingly, the swivel spring allows the sensor to remain briefly stationary just before the instant the load is picked up. This minimizes the initial condition error on velocity but does not eliminate it.

The accelerometer derived distance can be compared against the expected distance to quantify inaccuracies. In general, the quicker and more consistent the stroke, the more accurate the accelerometer derived position, alone, will be. A long and irregular stroke, particularly one where the blocks remain stationary for an extended period, is where the accelerometer is likely to produce inaccurate results. The accelerometer data can be "fused" or combined with the barometric pressure readings and the known travel length to provide an accurate position measurement through the stroke, even if there are long periods of zero velocity.

Wave Equation Analysis:

Once a good hook load and position data set is obtained for a stroke, the wave equation processes the surface measurements into a downhole dynamometer card in much the same way a pump-off controller (POC) or analysis software would. This downhole card resembles that of a "deep" rod part. In the absence of mechanical friction this should be a perfectly flat load line. Depending on the wave equation method, the "expected" load could also be set at zero. This "zero" reference load is important, as the stroke is in only one direction unlike a typical pumpjack, where the dyno card consists of both an upstroke and a downstroke. When looking at a traditional cyclic dyno card, the "bottom" or downstroke section of the card is intuitively observed relative to the zero or neutral load. In the case of a RigDyno downhole dynamometer card, there will just be a single line and its distance from the zero reference is a cumulative measure of friction. Other potential factors such as incorrect rod weight and significant inertial effects may also be present.

It is helpful to identify a region where the surface motion is traveling at a constant linear speed. This is not strictly required, but greatly improves the quality of resulting analysis at later steps in the process. The wave equation addresses changing velocities and their associated inertial load changes, but there are cases where the inertial effects do translate through to the calculated downhole card. In particular, the velocity at the end of the rig stroke may abruptly change and this inertial effect may show up in the downhole card.

The wave equation does not require a cyclic stroke, only that there are sufficient surface samples to calculate the conditions at the far end of the rod-string. In a typical pumpjack, the stroke is assumed to be symmetric with the preceding and following strokes. This assumption "generally" works in practice for pump-off control but is flawed as pump conditions may change from one stroke to the next. In this analysis, we are primarily interested in identifying a stable section of the stroke, from which to derive cumulative friction. This typically occurs around the middle of the stroke where the rig is operating in a consistent manner. The ends of stroke and associated discontinuities that may arise are not a concern in this "middle-of-the-stroke" region as the wave equation will have stabilized.

FIELD DATA:

Field measurements were obtained from several workovers to improve the process and improve the hardware sensing approach. The data presented here is the most recent, representing the overall design improvements from earlier field trials. The analysis and interpretation of this dataset is preliminary and should be considered as a proof of concept. Conclusions drawn from this single data set should consider this as subject to interpretation error. The sensor and analysis process provides detailed calculated downhole dynamometer cards for each stroke of the workover rig, largely as expected. Further analysis of these individual downhole dynamometer cards into a detailed friction map of the wellbore is preliminary. This is a new method of friction analysis and so new findings, and insight are to be expected as more data becomes available through this process. Improvements to the process from earlier runs result in the dataset presented here. Several improvements to the process remain.

Correcting inputs to the downhole card calculation is one area of improvement. Of note, the tubing string may be partially empty, which alters the buoyancy of the partially submerged rods. The viscous fluid damping factor in the wave equation is substantially different in the context of an empty, or partially empty, tubing string. In the interest of the initial analysis, using an unaltered implementation of the wave equation, the fluid density and damping factors were set very low. Determining changes in rig factors may be needed. For example, a shifting rig may cause rods to drag on the wellhead, creating additional friction, and this may occur at different times during the operation. Improving these assumptions and better determination of partially filled tubing are sources of future work.

The deviation survey for the main test well is a coarsely spaced drilling survey from 1955. **Figure 5** shows this survey along with the point of highest DLS (Dog Leg Severity). The geometry of this wellbore should be considered when analyzing the friction results. The full length of rods is likely in the same configuration as when the well is pumping, but as the rods are lifted, they contact the tubing in different points, and this may alter the friction results.

The polished rod and pony subs were omitted from the analysis. The process for handling these pieces is slightly different in the logged data and so it requires a bit of manual attention to properly identify these components. The “normal” rig strokes of full rods can be automatically and reliably identified through the stroke splitting phase. Likewise, the final rod sections and pump were also omitted since their weight was negligible and they were in a vertical section. Data was captured as these items were removed and could be incorporated into the analysis, but for simplicity the presented charts represent stands of 60ft rods (double California rods at 30ft each). **Figures 6** shows data starting at the first full rod section just below the polished rod and pony subs, ending with about 500ft of rods and pump remaining. The pump is a large diameter mass at the end of the rod-string. This may alter friction measurements in some sections of the wellbore. This is also a source of further investigation in the analysis of wellbore friction derived from this method.

Selected strokes (**Figures 7** through **Figure 11**) are presented as a representation of the data gathered to generate the friction plot in **Figure 6**. These plots (**Figures 7** through **Figure 11**) resemble a traditional dynamometer, with the exception that it is only an upstroke, with a very small downstroke near the end. The pulling process overshoots the top of stroke so that the rod elevator may be installed, and the rod-string lowered down on to it.

Traditional dynamometer analysis will show a “nose” of the pump card and one will recognize this as possible mechanical friction. This “nose” is the very beginning of the downstroke and represents a change of upstroke load with friction working opposite the rods, and the downstroke load where the friction reduces loads as the rods travel down. In a qualitative analysis of the dataset, this “nose” does get shorter as the rods get shorter and are exposed to less downhole friction. This observation is qualitative as the last part of the rig stroke may vary due to the rig operator. This short downstroke section is also subject to static friction as the rods change direction. We are primarily interested in dynamic friction, but static friction is an interesting source of further investigation to be identified through this process.

The friction observations from a short downstroke may be leveraged in future test runs by prescribing the rig operate in a way that provides a small and consistent downstroke to compare upstroke friction to downstroke friction. This phenomenon was not considered in the friction analysis presented here but is something to consider in future analysis and operating procedures for this sensor. Further operations such as pulling (or lowering) very slowly might uncover further insight into the behavior of static friction in the wellbore. Normal, operations such as pump spacing, when installing rods, might automatically provide this interesting frictional data.

Friction Map Compared to Sideloading:

Figure 6 was produced from the average calculated downhole loads, plotted vs. depth, and provides an overview of friction acting on different lengths of rods. This is somewhat comparable to a sideload plot generated from a rod design program. Both have depth along the vertical axis and show a measure of severity at each depth. In general, a sideload plot shows the friction-induced effects from a normal force and created by tension from weight *below*. The friction map generated by the presented method shows cumulative friction acting *above* the depth shown on the plot.

The sideload and friction plots in **Figure 6** are inverse measures of each other and should be considered when interpreting this plot. Incorrect or inaccurate deviation survey will corrupt the sideload plot. The friction map is more of a direct measure of actual downhole conditions, but care should be taken when assessing shorter lengths of rod-string since the contact points will differ from the longer rod lengths and increased tensile loads present while pumping. While both plots show a similar intuitive concept, they represent two very different things: normal force in terms of sideloading, and friction-induced tensile force in terms of the friction map. There is a relationship between these two concepts, but the effect is different in terms of depth.

FURTHER WORK:

The friction measurement approach is applicable to several other wellbore operations. Continuous rods present an opportunity to gather load and position data to map the wellbore at a constant and consistent velocity. The existing load sensor may be installed on a continuous rod rig and position determined by a rotary encoder on the injector. A version suitable for deployment on a continuous rod injector is under development. In the short-term, the existing load sensor itself may be deployed on a continuous rod injector to gather only load. While this alone may provide useful information, the context of positional changes to correct for inertial load changes is critical for mapping friction.

A downhole version of the tool is under development to be run on a wireline or sand-line for directly measuring the friction imparted to a smaller, fixed length section of rods as they travel through the wellbore. This should provide a clearer view of friction, but frictional effects are limited to the length of rods traveling through the wellbore. Both surface and downhole tools could be deployed during a workover for a more comprehensive analysis.

The initial analysis preformed on the test run, and presented in the following plots and figures, may be greatly improved. Many assumptions were made for the initial results and further understanding will be improved by additional runs. Addressing these simplifying assumptions will improve the overall results. Improving the Damping Factor, determining partially filled tubing, and closer observation of the rod contact at the wellhead (during the workover), are near-term areas of improvement.

The positional sensing approach developed through this work, along with other sensing mechanisms may be implemented on traditional pumpjack operations. Position sensing on pumping units has long been a source of operational problems. Hall Effect crank-arm sensors are notorious for misalignment and inclinometers are difficult to maintain due to their placement high on the pumping unit and may be less sensitive through parts of the stroke. A low-cost solid-state position device incorporating this, and other sensors, suitable for permanent installation on an operating pumpjack is under development.

Applications in other phases of the workover process are under consideration. A live feedback mechanism for determining pump spacing, determining pump leakage, fishing operations, and several others may be of interest to rig operations.

CONCLUSION:

The surface sensor for monitoring load and position of the workover process performs as expected. Once shackled inline on the rig it is relatively safe from rig crew interaction as it is generally above any action on the ground or in the derrick. The only concerns are mechanical is overload, which can be mitigated by removing the tool if stuck rods are encountered, or by installing it after a stuck pump is freed. Physical damage to electronic components is another concern. Future versions of the tool will be sufficiently ruggedized. The current prototype electronic housing is a 3D printed plastic part, and no substantial damage was incurred in the 5 trial runs to date. The electronics housing will be converted to a machined metal part in future versions.

The structural capacity of the load-cell may be greater than that of the rod-hook, rod elevator, or rod itself. While the sensor may safely undergo excess loading, the strain gauges may be damaged. The current prototype version of the tool is not designed or intended for excessive loads or “jarring” operations. In addition to the strict load, the shock loads of jarring may negatively impact the sensors. Future versions of the tool may be designed for these adverse conditions. If such procedures are encountered, the sensing device should be temporarily removed and reinstalled once the procedure is complete. Removal and reinstallation of the RigDyno takes less than 5 minutes total since it is just shackled in place.

APPENDIX:

UTILITY BEYOND FRICTION MEASUREMENT:

The RigDyno sensor can be deployed on any rod service rig regardless of cable configuration to provide a live plot of rod loads. A service rig will typically run double cables to increase running speed while handling rods. This precludes a traditional cable mounted weight indicator as all cables are in motion, and so the rig crew operates without the aid of a load measurement. Load-cells may be incorporated into the rig pads, but these are not available on all rigs, are cost-prohibitive to retrofit, and may not provide the resolution required to identify certain load conditions. The friction analysis is trying to identify tens of pounds and so the load measuring device should be optimized for the expected range during that phase of operation. Load-cells incorporated into the rig pads are optimized for much greater loads, meaning their resolution is greatly reduced. Additionally, as rods are handled, they are hung in the derrick, which would also show in pad-mounted load measurements. This can be addressed but is an additional step that may be subject to erroneous measurements, at the required resolution.

In the typical rod lifting cable configuration (double cables), a lack of load indication is generally not a problem as the rig operator has a good sense of feel for the strain on the rig. Handling rods is well within the lifting capacity of the rig, and so there is a lot of room for error when assessing load by “feel” alone. This “feel” for rig strain is subject to skill and experience and can vary from one rig and/or operator to the next. It is also difficult to audit a workover to identify rods that may be mishandled or substantially overloaded. A direct load measurement on the rod hook can provide valuable real-time feedback for the rig operator and a detailed logged record to review which can increase safety and improve the overall process of returning a well to production.

Pump Tag Down & Spacing:

A necessary part of the rod installation process is proper pump spacing. Ideally the pump plunger is set at an optimal distance such that its pumping dynamics comes close but does not make mechanical contact during the pumping cycle. To accomplish this, the rods must be raised a pre-determined amount before being hung on the pumping unit. This process is somewhat of an art as the rig must first lift the rods from the point where the rods are tagged, or resting, on bottom, to the point where all slack is removed. This is the zero point where the rods are statically stretched and just barely touching the bottom of stroke. The rods are then lifted from this point to the desired pump spacing distance. Because there may be no physical load measurement, this zero-point is determined by skill and experience of the rig crew. This can be further complicated as the force wave travel time in a deep well may be lengthy. In other terms, it may take some time from when the surface rod is lifted to when its load effect is transmitted down to the bottom of the rod-string and felt back at surface. This may be delayed for a second or more depending on depth and rod material.

The live wireless data link provides a real-time load plot that can be positively and objectively observed for these downhole load transfers to identify the point at which rods are statically stretched. This can eliminate a significant amount to subjectivity in the process of identifying the proper pump spacing. When stacked out on bottom the total rod load at surface will be slightly less due to the bottom section of rods resting on bottom. This load may not even be perceptible due to friction from wellbore deviations. As the rods are lifted and slack is taken out, the load will increase to a point where the load plateaus and the rig bears the entire weight of the suspended rod-string. This is the point at which the pump is precisely spaced on bottom. The rig will then lift the rods above this point by the desired dynamic spacing distance for the given pumping system. This process is easily observed and repeated while looking at a real-time load plot but is very subjective when performed by skill and intuition alone. This general utility applies to both sucker rod pump spacing, as well as Progressing Cavity Pump spacing.

This pump spacing process may yield valuable friction results as it provides several readings of up-stroke load and down-stroke load. This provides a differential friction measurement and is obtained on the full length of rods. This is a source of further investigation. Data during such a pump spacing was gathered during a previous run, but sensor improvements have been implemented in the meantime. Results from that test are promising, but new data with the sensing improvements are needed.

Vertical Position Indication:

The self-contained sensor is ideal for measuring rod loads because the rod hook is a single point of measurement for both load and position. The load sensor is easily installed in-line with this configuration (**Figure 1**). When handling tubing, however, the lifting configuration utilizes bails on the tubing elevator which make a single point of load measurement difficult. The position measurement approach may be utilized alone as an alternative to drum-mounted rotary encoders. Since the vertical elevation sensing is fully self-contained and available over a wireless connection, it may be attached anywhere along the lifting assembly or placed on the blocks themselves. In some respects, this position measurement may prove more accurate than the drum encoder. Whereas a position derived from a drum encoder must account for cable stretch and layers of cable as it is wrapped around the drum, the sensing approach here provides a position measurement at the point of interest.

Torque & Drag Analysis:
A common procedure in drilling is the Torque Drag Analysis (TDA). There are undoubted similarities between and there may be overlap with the models and software available in the drilling domain, that are not commonly available to the production department. Likewise, the sensing approach here may have utility in drilling by providing a measurement closer to the equipment under measurement.

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FIGURES:

Figure 1: The RigDyno™ is placed in-line with the rod hook. A second shackle is required to complete the connection. Once installed, the load-cell observes all load placed below, on the rod hook. The sensor also determines position of the rod hook throughout the stroke. Because the load and position are gathered at the same physical location and time, they are directly suitable for use as inputs to an unaltered wave equation.

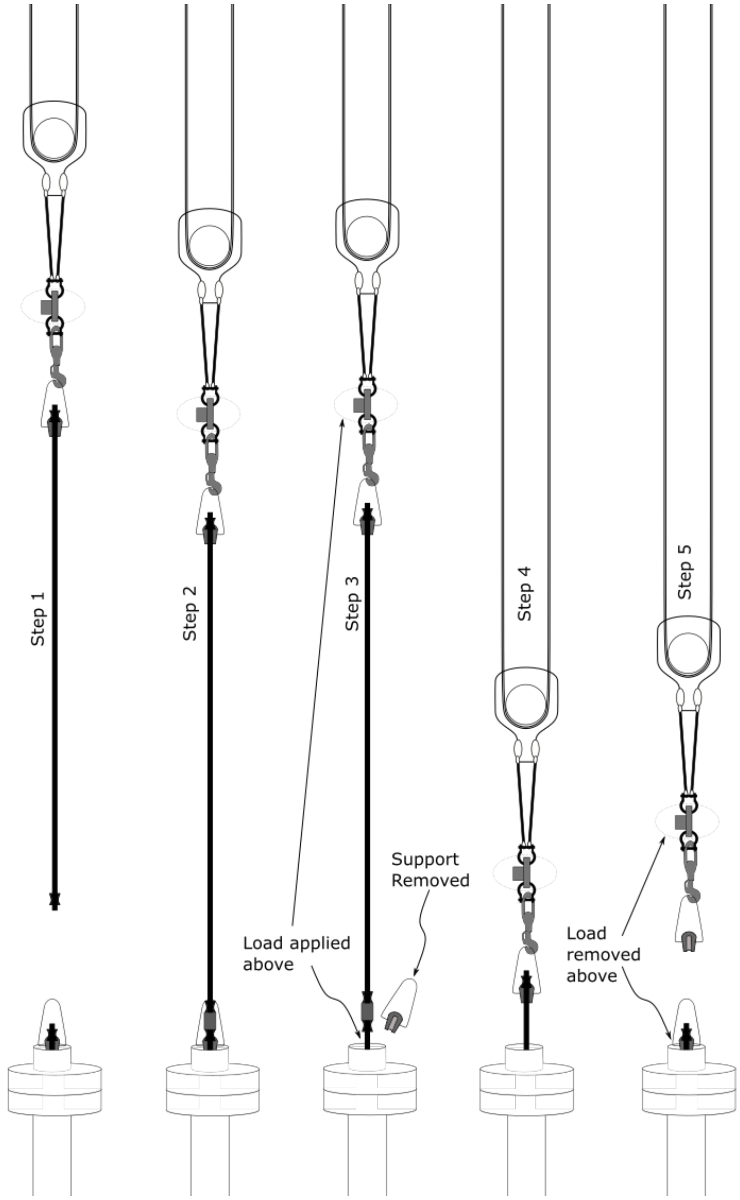


Figure 2: A typical workover process transfers rod load to and from the rod-hook as the rod weight is transferred on and off the rod table. This illustration shows rods going in the hole. The general concept is similar in reverse for removing rods. The load is transferred at exactly the same location on the rod table each time, the only difference is the elevation of the rod-hook, which in-turn indicates the direction of equipment being installed or removed. If load is picked up when the blocks are high, and removed when the blocks are low, a section of rods was installed. Conversely, if the load is picked up when the blocks are low, and released when the blocks are high, a section of rods was removed. The fact that load transitions at the same location, and that rod sections are a known length, allows the accelerometer to be calibrated for two fixed positions on each stroke.

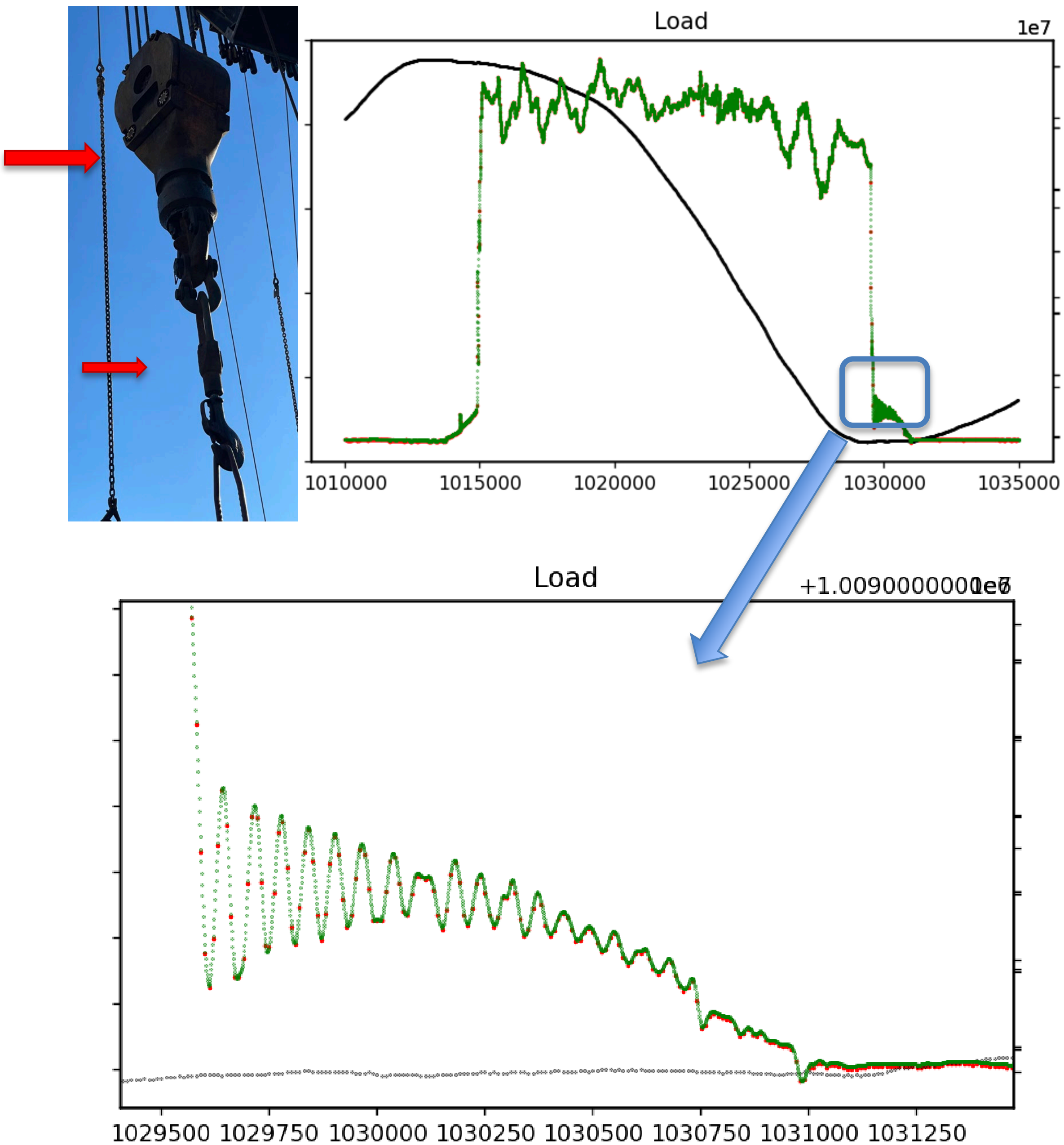


Figure 3: Shows a single stroke of the rig while installing rods. The end of the stroke is zoomed in, and the swivel spring compression (or relaxation) is visible. The horizontal axis is time in milliseconds. The Y axes are not to scale. This plot is for illustrative purposes only. The black line represents the vertical position of the sensor. Red dots show the load samples and green is an interpolated spline on the load data to better show the cyclic load values seen as the swivel spring relaxes when the load is transferred from the rod-hook, back on to the wellhead.

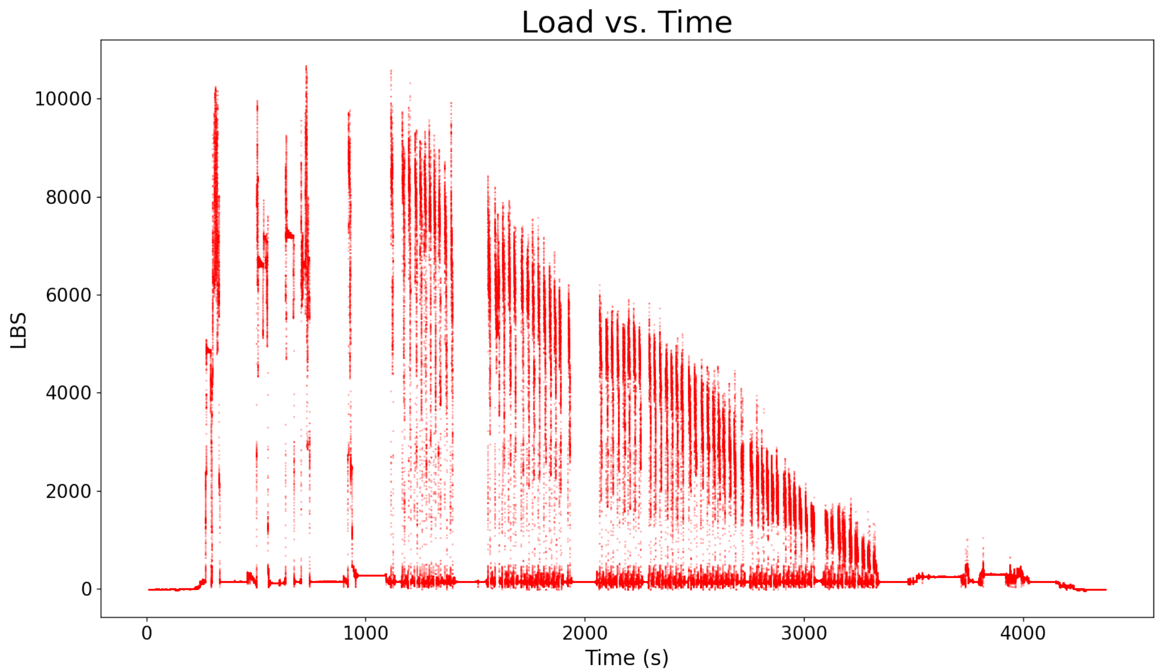


Figure 4: A plot of the entire run of hook load vs. time. This plot illustrated all activity of the rig throughout the operation. Each red dot on the plot represents a load sample and is sampled at 100Hz. The beginning of the process on the left involves removing the polished rod and several pony rods (0-1000 seconds). The pulling of rods then commenced (~1100 seconds) and proceeded consistently. The final section on the right (>3500 seconds) is handling the pump. Each spike on this plot represents a region of some interesting activity. To process this data, each section of load increase must be referenced to the position to identify strokes of interest. Individual strokes are then determined and processed individually. Figures 7 through 11 represent selected strokes from this run.

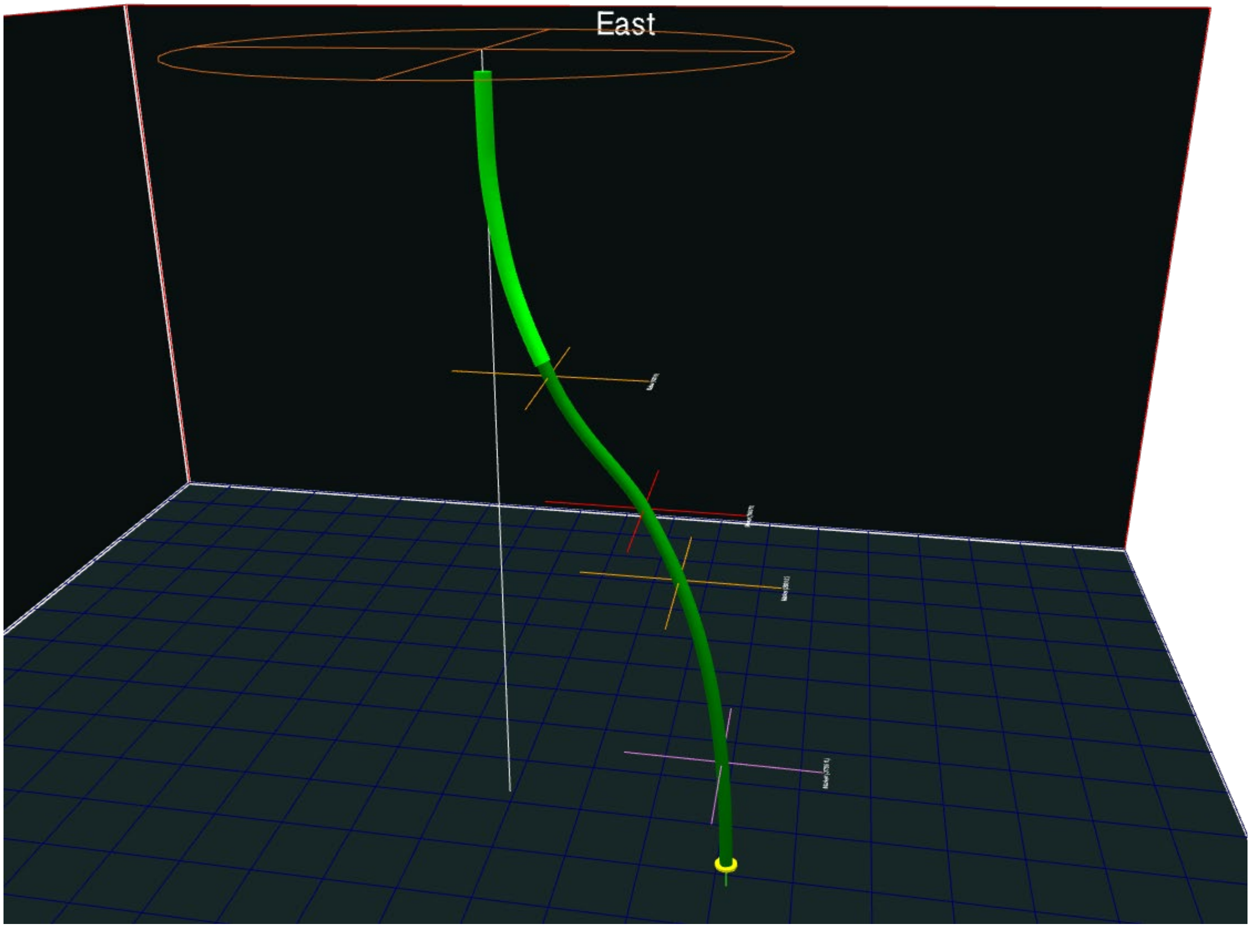


Figure 5: The drilling survey from the analyzed wellbore shows an "S" shape. The rod taper is shown in green. The point of highest DLS according to the survey is highlighted in red. Points of interest are also shown by the orange crosshairs and correspond to a range of apparent high friction. The purple crosshair also shows the upper end of a region of increased friction. This conclusion is speculative and requires more data to determine if this approach yields actionable information. This well does not have an anchor. The highlighted crosshairs above also refer to the reference lines on the following plot.

Rod-string details:

```
Polished rod 1.25"x22'
Pony subs 2x 6', 1x 4'
51x 7/8" (30')
95x 3/4" (30')
Pump 2.5"x1.75" 13'
```

Markers:

```
1620' Orange
2408' Red - DLS: 12°/100ft
2820' Orange
3780' Purple
```

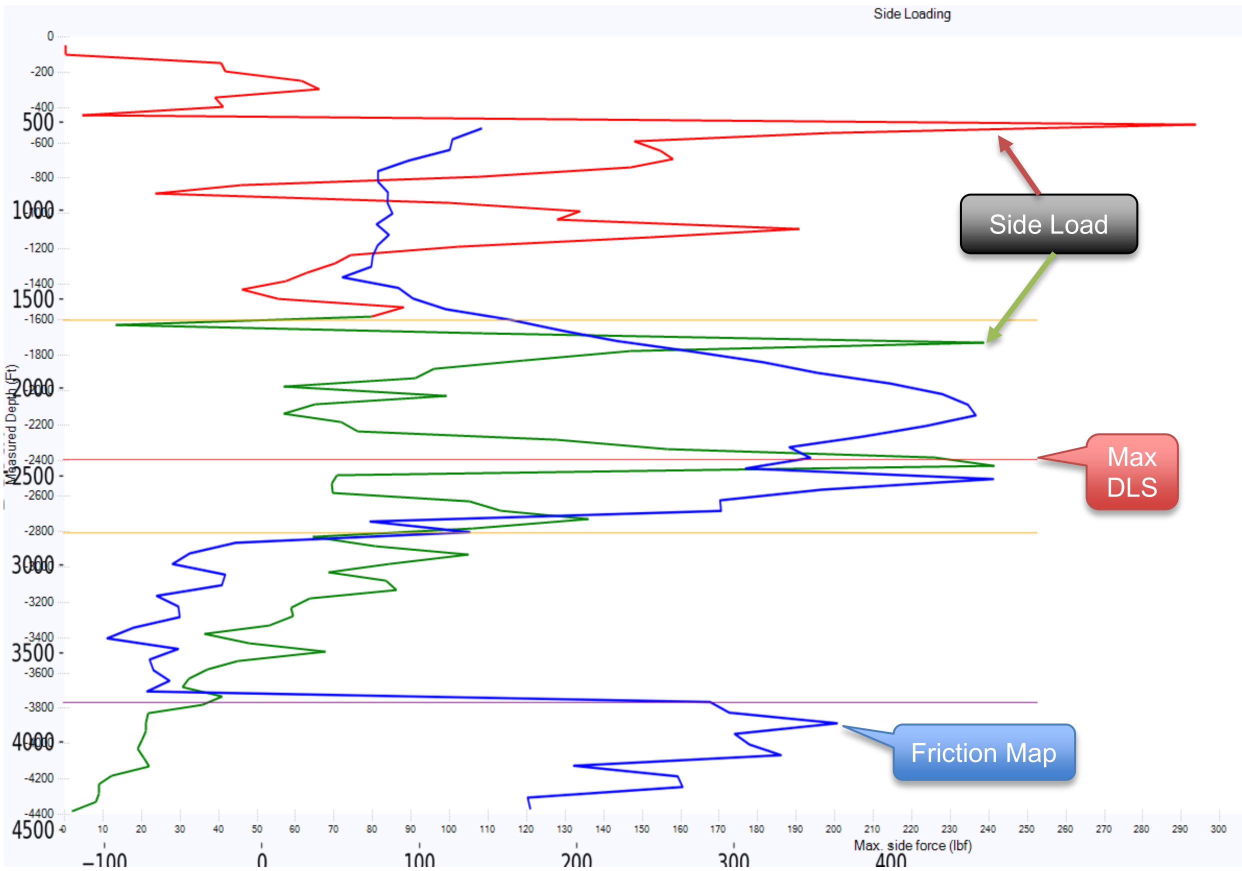
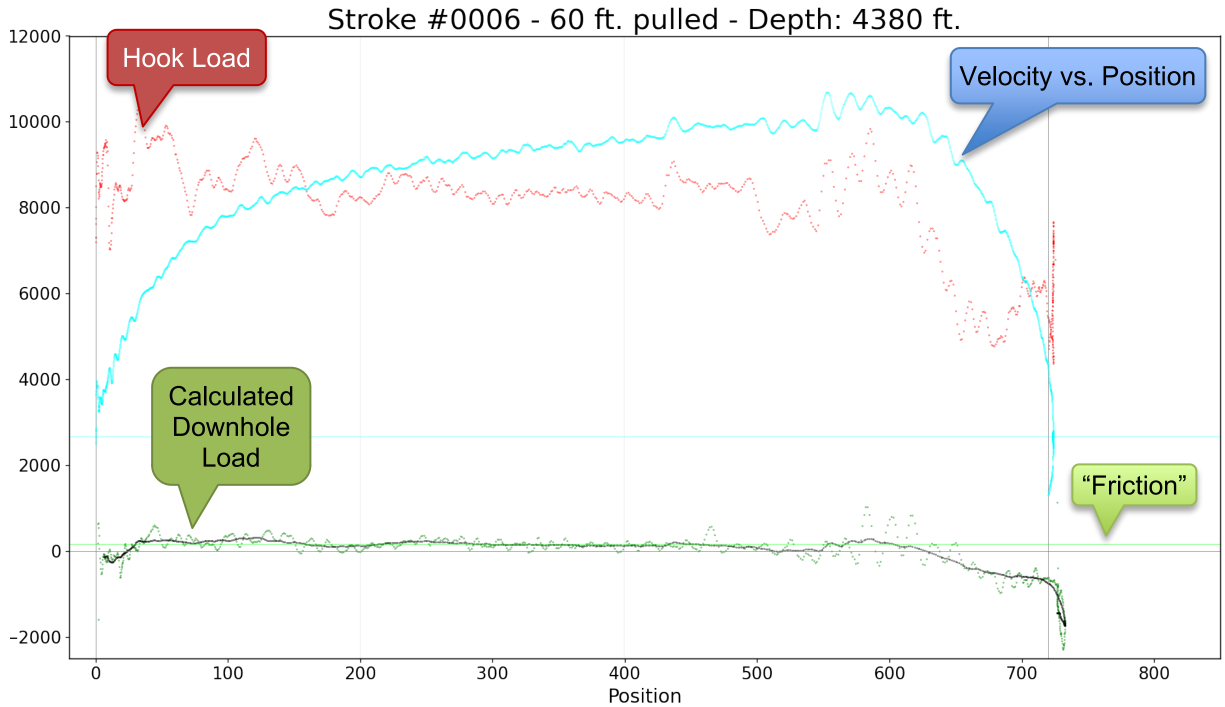


Figure 6: The friction map (blue) was overlaid on a sideload plot (red & green) using photoshop to align the depth axis. This is a preliminary analysis and should be considered in that light. More data is needed to fully understand the plot above and to determine if any correlation between the friction and sideloading values is merely coincidental. The friction map was generated using the average calculated downhole load between 200” and 400” on each stroke of the rig. The depth is the corresponding rod length in the wellbore for that stroke.

Sideload represents the normal force at a depth and is a function of the weight, or tension, *below*. The friction map obtained from analyzing rig loading is a measure of cumulative friction acting *above* that depth. These 2 plots are fundamentally different and serve different purposes. The horizontal scale was stretched to overlay the plot (this scale/axis is not equivalent).

The apparent correlation from about 2000’ to 3700’ and near the point of Max DLS could be an anomaly not yet identified in the workover or analysis process. For example, the rig may have shifted, causing the rods to drag on the wellhead. The location of the larger-diameter pump at the end of the rod-string in relation to wellbore deviation may also have a yet-to-be-understood effect on the plot above.



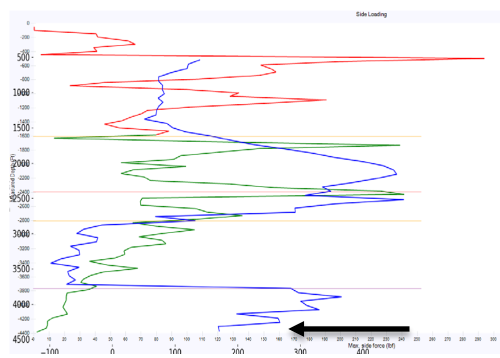
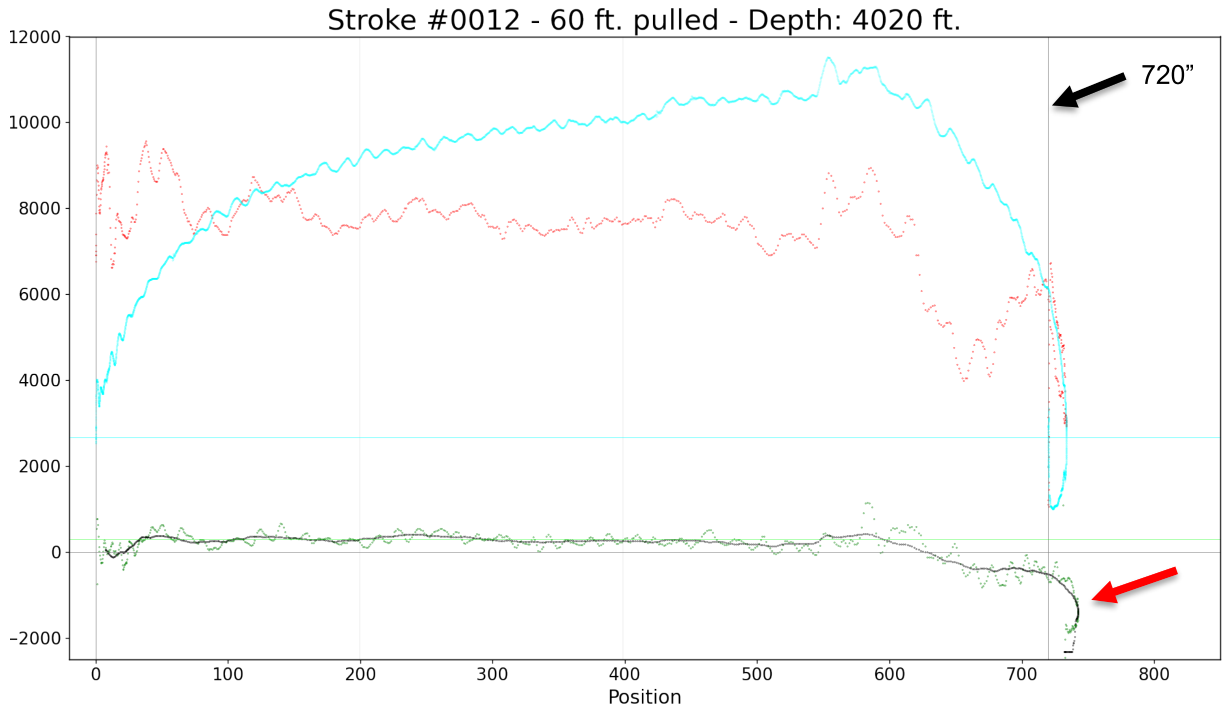


Figure 7: The following figures show selected strokes from the dataset. The surface plot begins immediately once the load is picked up and ends once it is released. Red (above) is the surface Load vs. Position and green (above) is the calculated downhole Load vs. Position in the same way as a traditional dyno card is presented. A running average of the downhole load plot is presented in black. This helps smooth out the noise in the downhole card. An inset of Figure 6 is provided to illustrate the length of rods from which the above dynamometer plot was generated.

Light blue (above) is a plot of surface Velocity vs. Position to help gauge dynamic inertial effects on the load. The average downhole load value is obtained from 200" to 400" for each stroke and is the basis for the resulting friction map (Figure 6). The horizontal light green line illustrates this value and is said to be "the cumulative friction acting on this length of rods" at that depth.

This is the first "full" stroke, but several shorter strokes were performed prior to this, including the polished rod, pony subs, and installing the rod table. Those smaller strokes were discarded in the following analysis. This stroke is with 4380ft of rods, plus the pump, in the hole. This represents friction over roughly the entire rod-string.



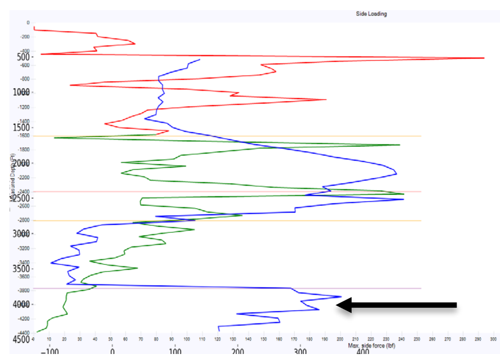


Figure 8: The length of the rods is 720”, but the rig overshoots the top of stroke a bit. This can be seen from the vertical reference line at 720” and where the load values continue passed this briefly and return. This creates a very short downstroke (red arrow) from which we can qualitatively observe friction. The height of this highlighted region (red arrow) is likely a qualitative measure of friction in both directions.

The length of this “downstroke”, and thus its usefulness in analysis, is dependent on the rig operator. This also represents somewhat of a dynamic overtravel of the unloaded rod-string since the overall stroke at the pump appears slightly longer than the travel of the surface stroke. It is unknown if this dynamic is detrimental to the rod-string or other wellbore equipment since the impact of this overtravel is then immediately transferred directly to the wellhead.

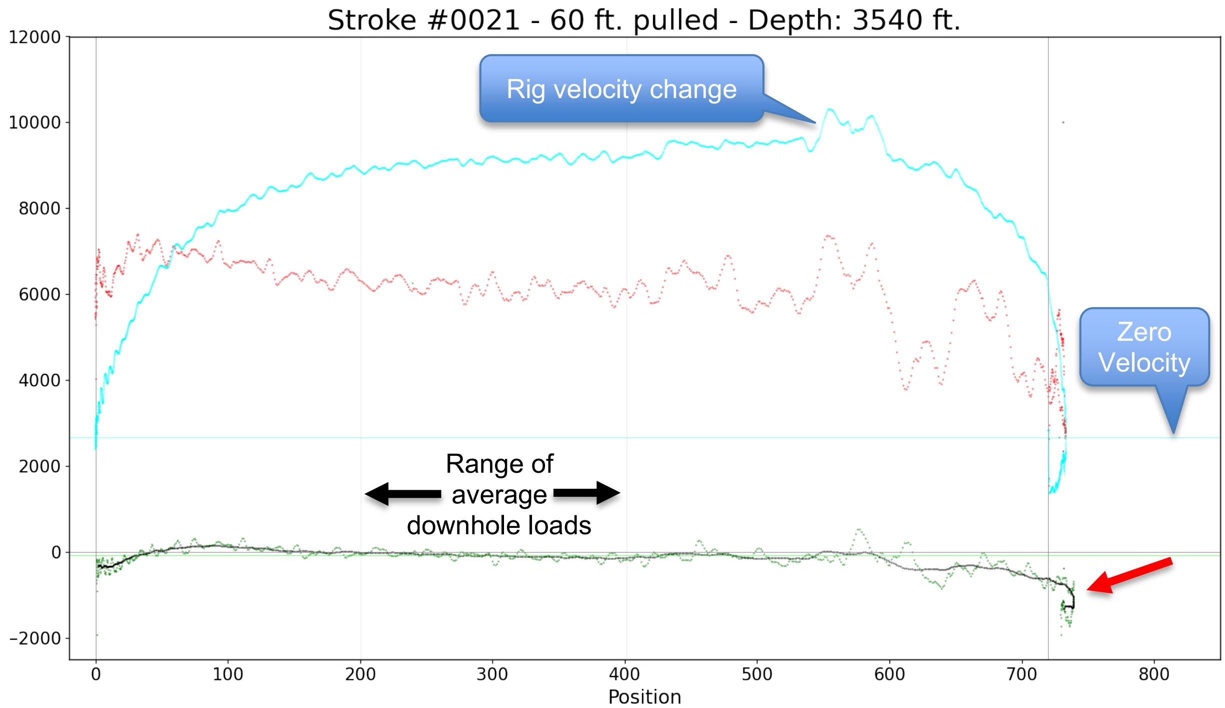
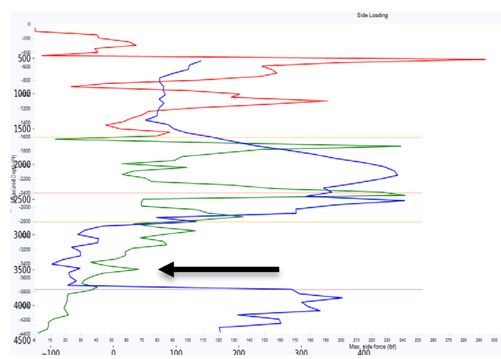


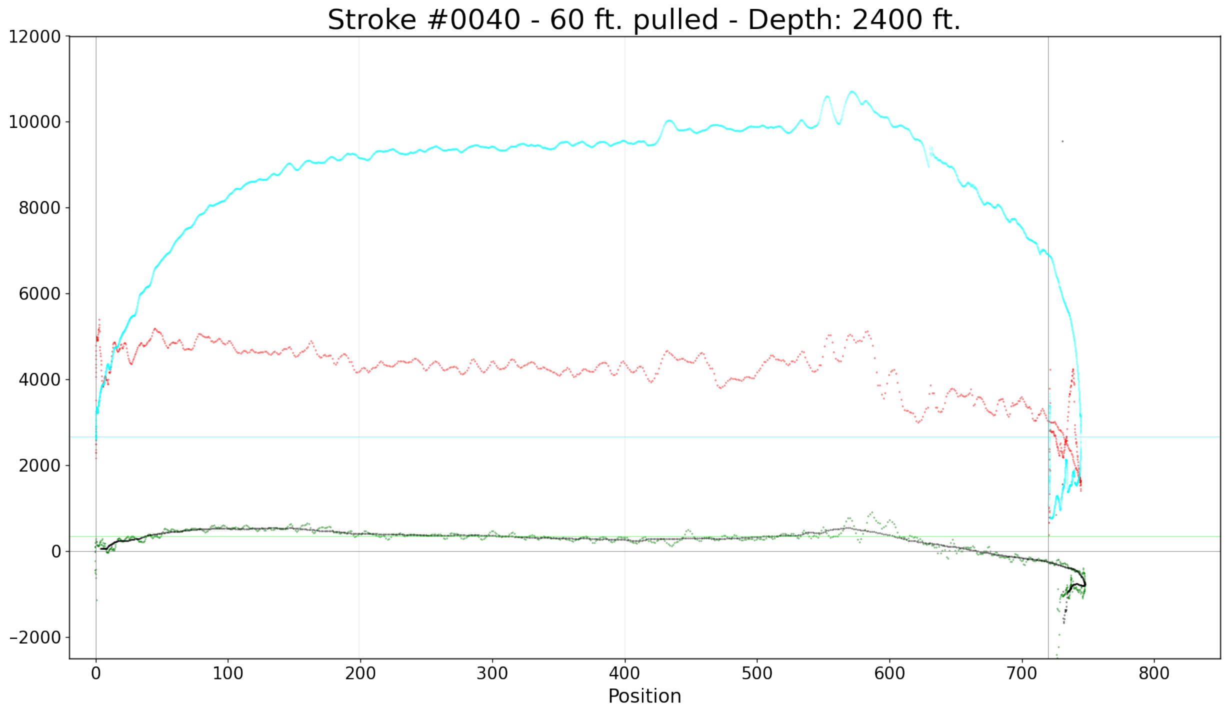
Figure 9: This stroke is from a range of apparently low friction between about 2900' to 3600'. It is not fully understood why this range drops in apparent frictional loads, or why the lower wellbore section increases in load (see Figures 6 & 7). The qualitative observation of the short downstroke (red arrow) also shrinks in this region.



The rig velocity change can be observed just before the system begins to decelerate. Inertial loads can be seen following this change and an echo of this dynamic is apparent on the surface load plot.

The range of interest in determining the average frictional value for the pump is illustrated from 200" to 400". This range was arbitrarily selected as a region of the stroke that consistently has stable dynamics. It follows the initial acceleration and is before the rig changes speed near the end of stroke. In other words, all the strokes look pretty much the same in this specific region.

This plot is from the region of apparent low friction, just above the purple marker (see Figures 5 and 6).



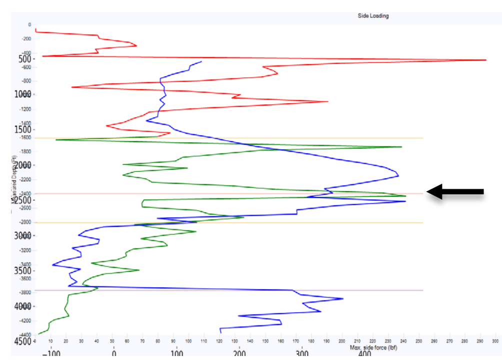
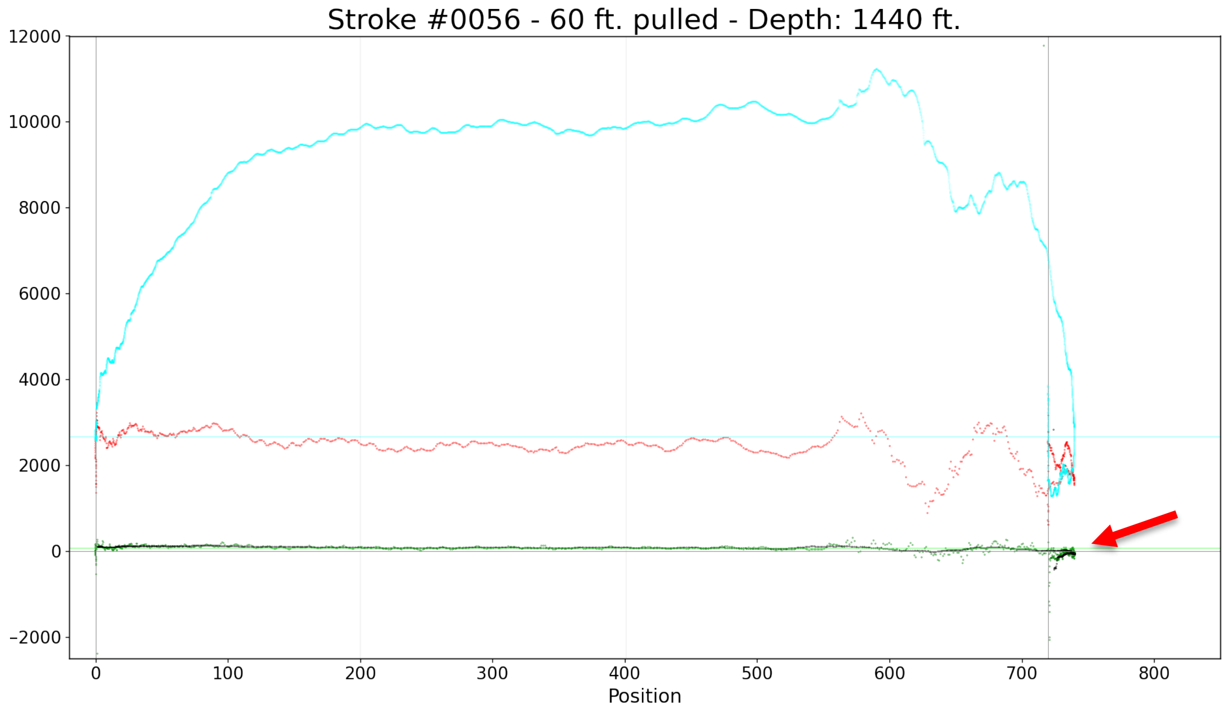


Figure 10: This plot is from around the point of highest DLS at 2408ft. This DLS is 12°/100ft according to the survey and was initially thought that this “may” represent an error on the drilling survey. Surrounding DLS values were <5°. Further investigation into the failures around this point may yield interesting conclusions. There is an apparent correlation in peak sideloading and a local peak in the friction in this vicinity. This is speculation at this point, but could for example, be used in justifying running a high-resolution deviation survey to better identify wellbore geometry in this region.



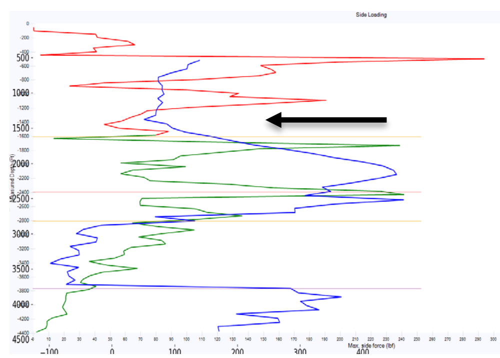


Figure 11: This plot is from the upper section of the wellbore, above the orange marker in Figures 5 and 6. Also note the height of the downstroke is smaller compared to Figure 8 indicating the friction is likely lower in this section. This makes sense because it is the upper section of wellbore, and the deviation (and this friction) is likely low. The rods are also shorter here meaning that there is less mass imparting a tensile induced normal force on any present deviations.

The sideload plot, conversely, shows higher values because there is more tensile load in this region. Interpreting a friction map in the context of a sideload plot requires a deep understanding of the values relative to depth because the forces of these two concepts are inversely related to depth. The longer (or deeper) the rods in the friction map, the higher the expected cumulative friction. The shallower the deviation on a sideload plot, the higher the value because of the cumulative tension forces acting below. Further work is needed to more intuitively combine these plots into a useful, actionable report illustrating friction present in the wellbore.