MEASURING WELLBORE FRICTION DURING WORKOVER OPERATIONS

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ABSTRACT:
Deviated wellbores, whether intentional or unintentionally drilled, are becoming ever more common. Rod-on-tubing friction occurs as a result of these wellbore deviations. This friction has a detrimental effect on the longevity of the equipment through accelerated mechanical wear. Downhole friction can also obscure analysis and optimization as the friction distorts the calculated downhole conditions. The only methodology currently available to account for this wellbore friction is by way of a wellbore deviation survey. Deviation surveys have varying degrees of resolution, from coarse 100+ foot surveys during drilling, to high resolution gyro surveys which can resolve one foot or better along the wellbore length. Geometry derived from the deviation survey is then used to infer mechanical points of contact between the sucker rods and inner tubing wall in conjunction with the wave equation methodology, tensile and side loads are determined. These are idealized calculated values because the geometry is indirectly measured, and rod-on-tubing contact points are not exactly known or understood. The work presented here attempts to directly measure friction along the wellbore.

Two fundamentally similar approaches are discussed. The first utilizes an instrumented rod-hook to measure load and position during a workover. Wave equation methods are then applied for each “stroke” of the rods by the workover rig while pulling rods out of the hole to determine dynamics along the remaining section of rods in the wellbore. A friction map can then be computed over the entire length of the wellbore as individual rod sections are installed or removed. A second approach utilizes a downhole tool, that measures axial load and acceleration, that is run inside/through the tubing on the sand-line or wireline. Because this tool is designed to run through tubing that is still installed in the wellbore, this operation would be performed after the rods are pulled. This is an optional approach relative to the instrumented workover method. If the sand-line or other wireline is used at this point, this tool can be added with minimal overall impact to the general process. A section of weight-bars of a desired length below (and possibly above) the tool provides an opportunity for friction to act during the trip through the wellbore. Correlating loads measured by the tool with position along the wellbore and eliminating dynamic forces due to acceleration of the tool itself, provides a directly measured friction map of the wellbore at or near the points of friction. Both approaches require little additional interaction from surface personnel as the work necessary to gather the data is already performed. All that is needed is to capture and process the data from those existing operations.

DEVIATION SURVEYS:
Deviation surveys (otherwise referred to as “directional” surveys) are primarily used for wellbore placement and to determine mineral rights. Modern advancements in surveying technology have greatly improved accuracy and have enabled a very detailed view of the wellbore and nuanced geometries that can impact rod-on-tubing wear. Because of wellbore constraints, the deviation survey is performed through observing orientation of a tool at discrete positions along the wellbore. Tool inclination, or angle from vertical, and tool azimuth, or compass heading, are used to provide a 3-dimensional *direction* at a given measured depth along the wellbore. It is virtually impossible to determine 3-dimensional *location* directly, and so the position must be inferred from measurable values, namely direction vectors of gravity and compass heading (or inertial reference in the case of gyro-based tools). Adjacent survey stations are used to create a mathematical model of an arc connecting the direction of the tool from one location to the direction of the tool at the next, given the arc-length (or measured depth) between survey locations. There are a number of mathematical methods to calculate the 3-dimensional Cartesian coordinates [X,Y,Z] from these survey

samples (MD,INC,AZI). These methods include “Tangential”, “Balanced Tangential”, “Average Angle”, “Radius of Curvature”, “Minimum Curvature”, etc. The Minimum Curvature method is generally accepted as the most accurate of the common methods. Each of these approaches assumes a smooth path between survey locations.

Of particular note in the surveying methodology is that, in order to obtain cartesian coordinates [X,Y,Z] for the wellbore path, survey derived coordinates are progressively added. In other words, to obtain the [X,Y,Z] coordinates of a given measured depth, the change in position (ΔX, ΔY, ΔZ) between each previous survey measurement and associated direction-to-position calculation are cumulatively added. This means that any error in survey measurement, or any error in applying the assumption of a smooth arc between samples, will accumulate with depth. Higher resolution surveys can reduce this error by minimizing the impact of the smooth arc assumption. As the distance between the sample points is reduced, the chance of mismatch between actual wellbore path and an ideal arc is reduced. Still, any measurement errors will compound into erroneous [X,Y,Z] coordinates. The drift of this error is somewhat limited by the independent nature of the survey measurements and is generally accepted as adequate for the purposes of wellbore placement.

In terms of wellbore geometry that can impact rod-on-tubing contact, the centerline of the wellbore (which is the general assumption of the survey) likely differs from the path of the rods. The centerlines of the wellbore, casing, tubing, and rods are not perfectly in alignment. This discrepancy can be on the order of a couple of inches. Other factors such as tubing tension can also significantly alter the path of the rods relative to the survey. Through-tubing deviation surveys are possible but may not match actual operational conditions. **Figure 1** illustrates a case of inadequate tubing tension in a mechanical anchor. In this case, a high-resolution through-tubing survey was performed at the existing tubing tension, and again at a higher tension. When calculating the two surveys independently, the *calculated* bottom coordinates were off by approximately 6 feet (Phillips, 2016). This is impossible because the physical casing is bounded, and the true coordinates could never deviate more than a few inches (or the diameter of the casing). This example shows compounding errors in the survey calculation methodology and that rod-on-tubing contact points may change from the “true” centerline of the wellbore. The ability to accurately resolve nuanced geometries that could impact the location and magnitude of rod-on-tubing is problematic. Surveys are certainly adequate to determine an overall geometry of the wellbore which may be sufficient to *understand* overall behavior of friction. To accurately *quantify* friction in the context of a rod pumped well a more direct measurement of actual friction is required. Adding this direct measurement to geometry derived from a deviation survey can greatly improve the understanding of friction in the wellbore.

WAVE EQUATION:

The wave equation is a well-known method for determining downhole conditions of a rod pump system. A detailed discussion of the mathematical underpinnings is beyond the scope of this paper, but numerous resources are available (Gibbs S. G., ROD PUMPING Modern Methods of Design, Diagnosis, and Surveillance, 2012). Of significance to this discussion is the understanding that the wave equation eliminates dynamic effects present in the stretch and acceleration of the rods during a pumping stroke. As a result of eliminating these dynamic factors, it is then possible to see the conditions present at the far end of the rod-string in terms of calculated load and position over the course of a pump stroke. In an ideal frictionless environment, the calculations are relatively straightforward. There are however two fundamental sources of friction present in a pumping well.

The first type of friction is a viscous fluid damping that removes energy from the rods. This frictional force is from fluid flowing in the tubing around the rods and is largely velocity and direction-of-travel dependent. The wave equation includes a term to handle this viscous damping, and is relatively well understood, primarily because this damping affects the rods along the entire length.

The second source of friction is mechanical contact between the rods and tubing. This friction is not well understood in the context of down-hole geometry and conditions and is primarily due to the lack of measured downhole load and position data from which to compare against calculated data. Mechanical friction is a function of the applied normal force and coefficient of friction. This friction only acts where there is a mechanical contact between rods and tubing. Factors such as rod and tubing type, size, and configuration, as well as surface finish and fluid properties all affect the friction experienced. Furthermore, this friction is also dependent on whether the local segment of rods is moving relative to the tubing or not. Static and dynamic friction behave very differently.

The current methodology of applying a deviation survey to the wave equation involves determining points of rod contact given gravity, tension, orientation, etc. Gibbs presents the free-body diagram of the rod segment (Gibbs S. G., 6-9 October, 1991) as a way to illustrate how the applied sideload is a function of applied tension and local geometry, gravity, etc. If the geometry is perfectly known, this method is reasonable. In practice however, and as discussed above, minor errors in the deviation survey can compound since applied sideload is a function of applied tension, and applied tension is impacted by other path deviations through the wellbore, which may also be in error. One example would be a coarsely spaced drilling survey, with a significant, but unrecorded deviation between survey locations. Such a discrepancy between calculated geometry relative to actual wellbore geometry can corrupt the friction models derived from those erroneous spatial coordinates.

GIBBS CONJECTURE:

Sam Gibbs pioneered the use of the wave equation in rod pumping design and analysis in the 1960's. During this period, wellbores were largely assumed to be vertical and so the 1-D damped wave equation could be applied to determine downhole conditions without considering mechanical friction. Additionally, with the increased water volumes of secondary recovery, the lubricity between the rods and tubing has dramatically changed the impact of downhole friction. In the 1980's and 1990's, deviated wellbores (whether intentional or unintentional) became more common. Gibbs again pioneered the understanding of how geometry and friction impact the pumping system and corresponding mathematical models. Gibbs presents a key observation that is vital to the methods presented in this paper. The Gibbs Theorem, or "Gibbs Conjecture" states that unaccounted friction will show up in the resulting calculation of the diagnostic downhole pump card from a measured surface dyno (or conversely, the calculated surface card of a predicted dyno will lack this additional friction).

> **Gibbs' Theorem**: *Solutions of the wave equation that match measured time histories of surface load and position will produce the exact downhole pump card if the friction law in the wave equation is correct. In computing the pump card, no knowledge of pump conditions is required. Any error in the friction law will cause error in the computed pump card.*

Of importance to the discussion below is friction *will be present in the calculation*, but we cannot determine *where that friction is acting* along the rod-string. The result is erroneously calculated pump load and position, which in turn distorts the pump dyno card, making accurate qualitative and quantitative analysis of the downhole conditions impossible. During a workover, we have a unique opportunity to gather surface "dyno cards" at varying depths. As sucker rods are pulled out of the wellbore, friction can only act on an ever-decreasing section of rods. We can therefore speculate the only difference between one "stroke" and the next (where a section of rods was removed) is due to friction no longer acting on the bottom section. The reality is slightly more complicated, as contact points, contact surface finish, lubricity, fluid level and several other conditions may vary. Nevertheless, when viewed cumulatively and processed to account for these variables, the resulting analysis is a map of friction acting at various depths. This friction map is directly measured and can greatly improve the friction model used to calculate pump cards. Utilizing this friction map can reduce errors in the friction applied trough the wave equation, and in accordance with the Gibbs Theorem, better friction models will improve the quality and accuracy of the calculated downhole cards. Improving the accuracy of downhole friction models applied to the wave equation will help engineers better address this friction.

FRICTION DISCUSSION:

Friction in general is well understood. The behavior of friction, as it pertains to downhole conditions, however, is not thoroughly understood and so a brief discussion is presented. Friction can occur as fluid drags on the sucker rods during the stroke. This is referred to as viscous damping and is generally handled in the common wave equation implementations. Viscous damping is velocity and directionally dependent and is reasonably understood in pumping wells. Methods to calculate damping are available (Everitt & Jennings, 1992). A different type of friction also occurs between the mechanical contact points along the rod-string and tubing wall. The scope of this paper discusses the mechanical friction, also referred to as Coulomb Friction.

Mechanical friction is directly proportional to the normal force applied, and independent of the contact area. The force caused by friction opposes the force applied in the direction of travel. In the case of a rod-string, friction-induced resistance is related to the normal force applied to the contact surface, in this case the rod on the inner tubing wall. This resistance force is affected by tensile-load-altering friction above and below depending on the direction of travel. The magnitude of a friction induced force acting on the rod-string is complex and dynamic. Mechanical friction is a product of the material interface, known as the coefficient of friction. This coefficient of friction depends primarily on the material interface, but also on whether the two surfaces are stationary (static friction) or sliding (dynamic or kinetic friction). **Figure 2** illustrates a typical friction plot where static friction resists initial movement. Once the static friction is overcome, the resistance transitions to a sliding friction which is generally less than that of static friction. While most of the stroke in an operational well experiences dynamic friction, it does experience static friction on every stroke when the rods change direction. In addition, harmonic vibrations can cause the rods to experience static friction multiple times during the stroke, and at different depths. Because the rods are elastic and dynamic, the seemingly straightforward problem of static vs dynamic friction becomes increasingly complex in both time and space.

Typical rod design and analysis software reduce the complex friction problem to a single coefficient of sliding friction in vertical wellbores. Under some conditions this may be a reasonable simplification as the static-to-dynamic friction transition occurs rapidly, at different depths and times during the stroke. As a result, the overall magnitude of the “additional static” friction force is relatively small compared to the overall tensile load. There are however an increasing number of wells with significant deviations, which in turn cause a substantial side-load, making the magnitude of that static-to-dynamic friction transition more significant. This, as pointed out by the Gibbs’ Conjecture, results in calculated downhole conditions that are not accurate, and in some cases misleading.

Better understanding of the behavior of friction in a well can improve analysis, but moreover can aid in prescribing mitigation actions to help address this downhole friction. The effectiveness of those mitigation actions can also be assessed through an improved friction model. Changing well conditions can also contribute to changing friction. Examples of this changing friction are worn rods vs. new rods, changing fluid properties, solids in suspension, etc. While this paper does not discuss these in detail, the location of these rod-on-tubing contact points, and the quantitative measure of friction acting at these contact point, can be helpful in diagnosing these changing conditions on future operations.

BEHAVIOR OF A DEEP ROD PART:

The key concept in this approach is the behavior of a deep rod part on a pumping well. This condition is functionally identical to the case of pulling (or installing) rods with a workover rig. In these cases, the rods do not experience the cyclic loading caused by pump action. Furthermore, the load experienced at the bottom of the rod string is known to be zero which allows for us to clearly see the frictional effects present on the entire rod-string on the pump card. This non-zero load value is directly related to friction. Unfortunately it is substantially small compared to the overall loads experienced by the lifting equipment. This requires very accurate sensing on the load to properly quantify. **Figure 3** shows a typical rod part as a “mostly” flat line set at zero (depending on the method used for calculating the wave equation). If the well were perfectly frictionless, the calculated pump card load would be exactly zero, and the only dynamic variation would be present in the positional data over time. As the well does have friction, small non-zero loads can be observed on the pump card in this case. Friction manifests in erroneous load and position data shown in the downhole pump card. We are primarily interested in the non-zero *loads* present in the calculated pump card as this is evidence of friction. Note, this is somewhat of an oversimplification because the position variation is also particularly important. It is however less easily observed relative to a fixed position at a given time. Load is much easier to observe relative to zero, which is known to be zero at the unattached end of the rod-string. The general method discussed is to gather these non-zero loads at varying depth to those non-zero calculated downhole loads at varying depths.

WORKOVER RIG SENSING DEVICE:

In order to apply the wave equation method, time synchronized surface load and position data is required. Pump-jack automation has largely solved this problem in operational wells, but no such sensing device is readily available to gather this high-frequency, high-accuracy load and position data during a workover. Recall the reason to perform these calculations during the workover procedure is to capture the friction effects at varying depths. In theory, one could reattach the remaining sucker rods back to the pump-jack and gather data in between each rig pull. This is of course impractical, and so a device that can seamlessly interface with the rig during normal pulling operations is preferred. The goal is to gather this data without slowing or altering the rig crew's process.

There are a multitude of ways to instrument a workover rig to obtain both load and position of the rod-hook. One such example would be to utilize the weight indicator for rod load. This presents a problem as the weight indicator is generally not sensitive enough for the friction values we wish to measure, and is potentially affected by forces other than the strict load on the rod-hook. There is also a concern about varying cable weight added to the load measurement as the cable is unwound from the drum. For load measurement, a tension link load-cell was selected to be placed at the rod-hook to measure a clean and direct rod weight. See **Figure 4**. This provides a direct measure of rod weight without external influence. The drawback is an additional link in the lifting assembly. This could be eliminated in future iterations by instrumenting the rod-hook or shackle directly, providing a seamless integration with the rig.

With regards to position, a rotary encoder could measure the extension of the drill line to determine position of the rod-hook. A substantial amount of cable of varying length is present between the stationary rig floor (or draw-works drum) and the rod-hook. The wave equation input would need to account for the substantial elasticity of the cable as well as the varying length. The existing implementation of the wave equation does not account for removing material during a stroke, and so significant modifications would be required to handle position measurement at the cable. Additionally, spatial separation of the load and position measurement would also present a challenge. In order to mitigate these concerns and afford a simple design, a position measurement method utilizing an accelerometer is incorporated into the same load-cell placed at the rod-hook. This allows position and load to be gathered at the same time and place without the additional complexities of cable variations.

In short, the prototype sensing device developed for this application measures both load and position at the rod-hook and is completely self-contained. This is accomplished through a sensor fusion approach, but primarily dependent on an accelerometer and a traditional load-cell. A convenient dynamic of rig operations when pulling or installing rods is that the load transfer always occurs at the same location on the rod table (wellhead). The rod section, being installed or removed, is a known length and therefore provides two distinct points in vertical space which can be used to calibrate the accelerometer for absolute position on each stroke. See **Figure 5**. This is vitally important in the double integration required to convert accelerometer data to velocity and then position. The ability to re-calibrate or "zero" position at the beginning and end of each stroke of the rig greatly improves accuracy. Several other sensors are also incorporated into the device to further aid in the accuracy of the position through the stroke.

The prototype sensing device, RigDyno™ is ready for testing on real world conditions.

RIG OPERATIONS:

The sensing device is placed in line with the rod-hook. In the current form, the sensor is placed at the shackle between the bails and rod-hook. A standard tension link load-cell is used, which requires a second shackle. In the common operational case, the acquisition of data does not significantly alter rig crew operations. The ideal load-cell would be sized to the loads desired to be measured, specifically the weight of the rod-string under dynamic conditions. The capacity of the load-cell may limit some rig operations, such as jarring, or shearing downhole equipment; conditions which are not useful for friction measurement. Under such conditions, the rig crew would simply remove the load-cell until the rods are freed. This is only a limitation in the current configuration as an off-the-shelf load-cell was used for the prototype. The device can be re-engineered to increase the over-load capacity for the safety and convenience of the rig crew while preserving a narrow sensing range without damage to the load sensing components.

The general procedure for running this prototype device is to install the sensor above the rod-hook, turn the sensor on, and proceed pulling or installing rods as normal. The sensing device logs high frequency load and positional data onboard and must be downloaded at the end of the job. A Bluetooth interface is provided to monitor live data, but the rate at which raw data is generated, and the reliability of the wireless link in this initial prototype necessitate on-board data logging. The downloaded data is post-processed to derive the friction map, but it is conceivable to process the data in near real-time. This processing involves identifying the individual strokes of the rig, tallying the equipment remaining on the wellbore, and calibrating/calculating the position through each stroke. The processed stroke load and position data, along with the rod-string parameters are then fed through the wave equation to determine the downhole conditions for each stroke. Recall that the downhole calculated conditions will contain the cumulative friction acting along that length of rods for that stroke. Each stroke and its cumulative friction values are then plotted vs. depth to reveal the friction map through the wellbore. Friction is quantified in terms of tensile load. To be useful, this load value needs to be converted to a coefficient of friction, which can then be used in further design and/or analysis.

Additional Rig Crew Procedures:
Data acquisition during normal workover operations gives friction measurement largely under dynamic/sliding friction conditions. This allows the rig crew to proceed with minimal alteration to their existing processes. It is possible, with a slight and brief change in the rig crew workflow to measure static friction. This can greatly improve the friction map because it provides a distinctly different dynamic to the buildup of friction. Briefly, this procedure would have the rig pull the rods very slowly in an attempt to get them to stick and slip on the downhole static-to-dynamic friction transition. From this stick/slip, a depth can be determined from known rod properties.

The knowledge that static friction imparts a higher oppositional force can be used to help map friction in the wellbore. Under certain conditions this phenomenon can be observed in operational wells (Rowlan, Taylor, & Skinner, 2019). **Figure 6** shows an example of this in a running well. In short, static friction via rod stretch can be quantified through Hooke's law by observing rod stretch at surface and correlating the slope of the load vs position to a corresponding k_r of a length of rods. This can identify the depth of probable deviation-induced friction. It can also help to assess the magnitude and severity of this friction. Unfortunately, in an operational well, the transition between static and dynamic friction occurs rapidly due to the stroke rate. To properly observe this phenomenon, the rod velocity needs to be slowed, or the magnitude of the static friction needs to be substantial.

When we are attempting to measure static friction, the rods need to be moved sufficiently slowly to observe the buildup of tension before it is released by the downhole frictional resistance as the friction transitions from static to dynamic. In other words, the downhole sticking is released once the tensile load overcomes the resistance. While this is largely impractical in an operational well, due to motor and torque limitations, it is quite easy for a workover rig to pull rods very slowly in order to observe and measure this downhole "sticking". Again, the common case is to pull the rods at normal speed without restricting rig crew operations. This "slow pull" procedure can be performed occasionally or repeatedly at specified intervals or specific points of interest to improve the friction mapping. This "slow movement" of the entire rod-string using the workover rig can also be preformed in the downward direction to further observe frictional resistance.

<u>ALTERNATE DOWNHOLE SENSING METHOD:</u>
The approach of measuring the rod load and position at surface, to in turn measure friction acting along the remaining rods, can be applied downhole as well. A modified sensing device (See Figure 7), using largely the same core components, can be deployed on a wireline, or more conveniently, the rig's sand-line. In this case, a small section of rods is hung from a load-cell, which is in-turn hung on the sand line. The entire assembly is run through the tubing in the wellbore while load and position data are collected on the downhole sensing device, or in conjunction with surface sensors such as a cable line payout measurement.

The weight of the rods below is known and so any change in this load is measurable by the integrated load-cell. Change in load can occur from dynamic forces, which can be accounted for, given the corresponding positional data. Specifically, the integrated accelerometer can identify movement of the assembly and this information can be used to correct for dynamic motion. Additional changes in observed load, once dynamic forces are removed, are likely due to friction acting on the section of rods below the device. The overall position of the tool when those resistances are observed gives a map of friction vs. depth.

In highly deviated wells, some of the rod weight will rest on the tubing. This is an interesting case because friction will impact the tensile loads seen by the loadcell, but the reduced weight component will also affect the load. In this case, the inclination of the well in that section can be utilized to determine the expected tensile component of the rod weight. The deviation survey, or more conveniently the integrated accelerometer can be used to determine the wellbore inclination. The important observation is the multitude of sensing opportunities during a workover can all be leveraged to provide a more comprehensive view of downhole friction and this can be done with minimal impact to overall workover processes.

Optimally sizing the length, type, and weight of the rod section in this approach is dependent on the wellbore geometry and friction to be observed. The case of the load-cell on the rod-hook is an ever-decreasing (or increasing) length of rods, but from a fixed measurement location. The downhole tool approach is a fixed length of rods with an ever-changing measurement location. Either of these approaches yields frictional data and can be implemented independently. Combining these two approaches, along with a high-resolution deviation survey can yield a good friction map.

FUTURE WORK:

The prototype surface sensor has been constructed and is awaiting field deployment. Surface safety concerns with regards to the rig crew have been addressed as the current iteration is an additional link in the critical lifting assembly. Future iterations will either eliminate this additional link through directly instrumenting existing components or will provide additional mechanical overload protection to meet or exceed lifting component load capacities.

The electronics for the surface tool have also been altered to be compatible with insertion into a downhole tool. The downhole tool is currently under construction and are nearly ready to be deployed on a wireline or sand-line.

Because this is a new dataset, existing implementations of the wave equation would need to be altered to accept a friction map directly. This should not be overly difficult as the 3-dimensional implementations already determine some notion of friction through geometry inferred from the directional surveys. Integrating friction map into existing “3D” rod design and analysis software should be straightforward. Implementing a more comprehensive model involving static and dynamic frictional components and the varying transitions vs depth and time may be challenging because most rod design and analysis packages use only a single coefficient for friction.

CONCLUSION:

In conclusion, the tools and concepts presented here can help augment existing practices, of inferring downhole friction, through direct measurements. The necessary procedure and process for measuring friction is already performed by existing well workover operations. All that is required is to capture and process data from that activity. This results in a convenient and relatively low cost supplement to directional surveys for the sake of rod design and analysis for a given well.

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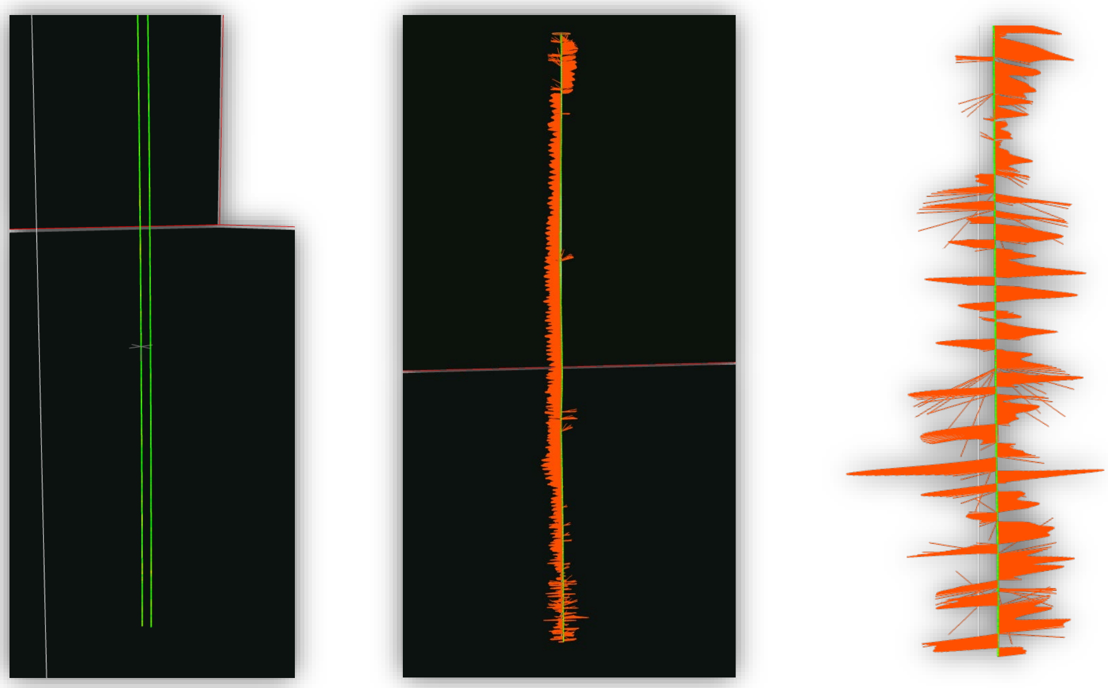

Figure 1: Comparison of through-tubing deviation surveys differing by only applied tubing tension. Errors compound to result in [X,Y,Z] coordinates that are off by 6½ ft. over the length of the wellbore. The illustration on the left shows both surveys plotted from surface and the resulting spatial difference (6½ ft.) at the bottom of the survey. A method of comparing surveys over a shorter interval was presented and vector “arrows” were overlaid to illustrate the magnitude and direction of the survey differences over subsequent 25ft intervals. The center illustration shows the localized differences between surveys over the entire wellbore. The illustration on the right shows (what is thought to be) tubing slack being pulled down to the bottom of the well by gravity on an improperly tensioned mechanical tubing anchor.

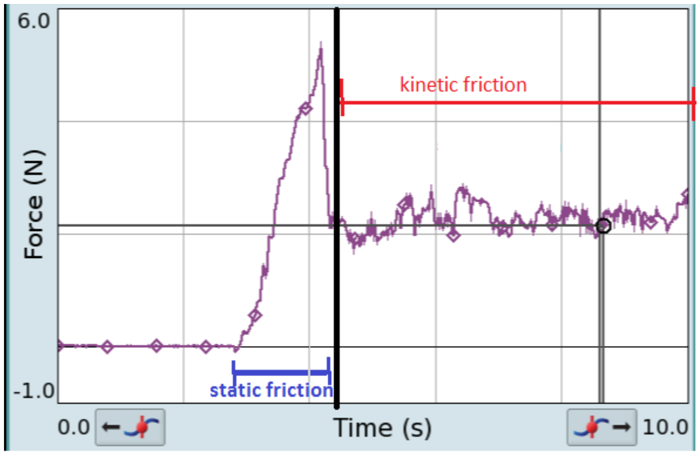

Figure 2: Friction plot of force applied vs. frictional resistance over the static (non-moving) and dynamic (moving) phases. In general, the force required to start moving an object subject to friction is greater than the force required to keep it moving. This results in two coefficients of friction. This transition occurs rapidly in a pumping well, and occurs at different times and locations through the rod-string. This typically means the effects of static friction are minimized, or at least unobservable at the sample rates and resolution typically available to rod pumping diagnostics. (Image source: Wikipedia)

Figure 3: The pump dyno card of a deep rod part, in the absence of friction, would be a perfectly flat line with zero load. In practice and following the Gibbs Conjecture, the calculated load at the bottom of the rod-string is non-zero and indicates friction acting somewhere along the rod-string. Other factors such as incorrect damping or incorrect rod count can also impact that load. (Image source: Echometer TAM example “RodPart_NoPlunger”)

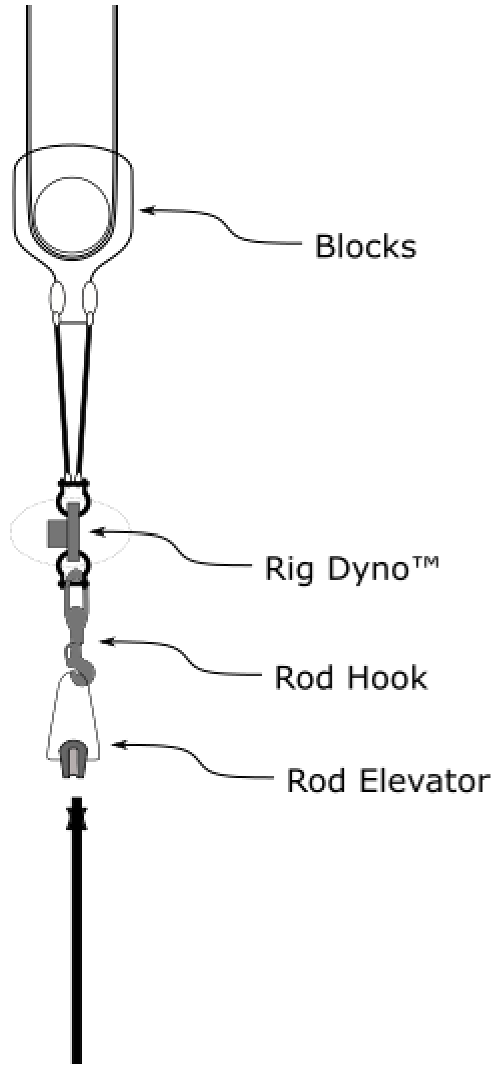

Figure 4: The general configuration of the sensing device on a typical workover rig when running rods. Ordinarily, the rod hook is shackled directly to the bails. The prototype device is inserted into this connection with a second shackle. Other load sensing devices, such as a directly instrumented rod hook or shackle, could simplify the installation.

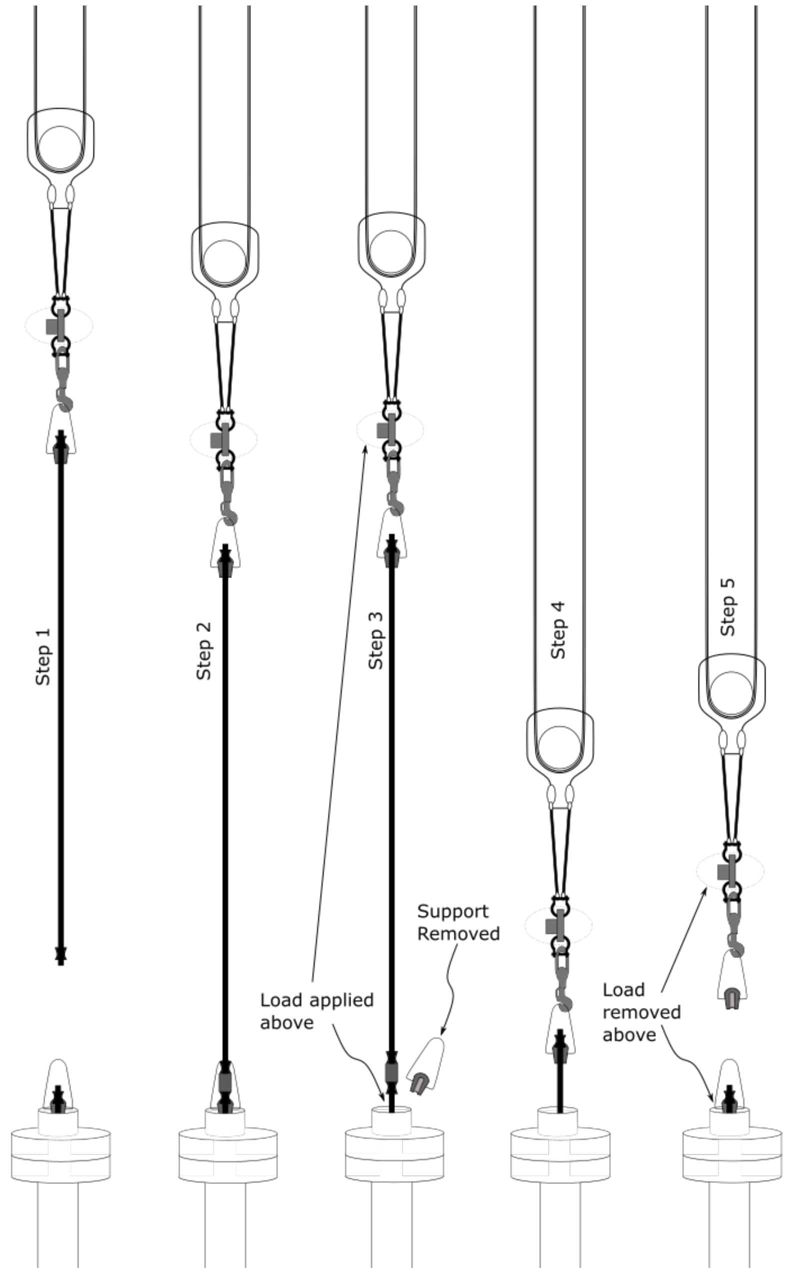

Figure 5: A typical workover process transfers rod load to and from the rod-hook as the rod weight is transferred on and off the rod table. This illustration shows rods going in the hole. The general concept is similar in reverse for removing rods. The load is transferred at exactly the same location 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.

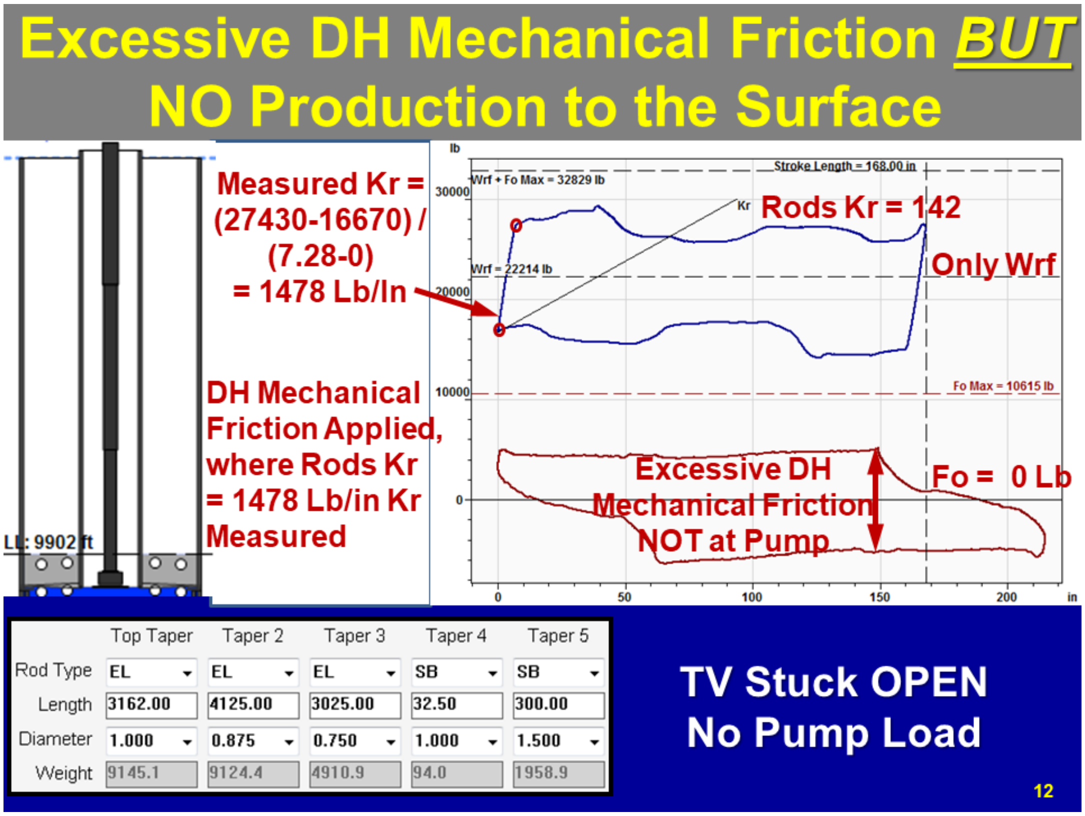

Figure 6: Plot of a dyno card on a running well exhibiting the transition from static to dynamic friction. The depth and relative magnitude of this friction can then be calculated from the rod properties. (Rowlan, Taylor, & Skinner, 2019)

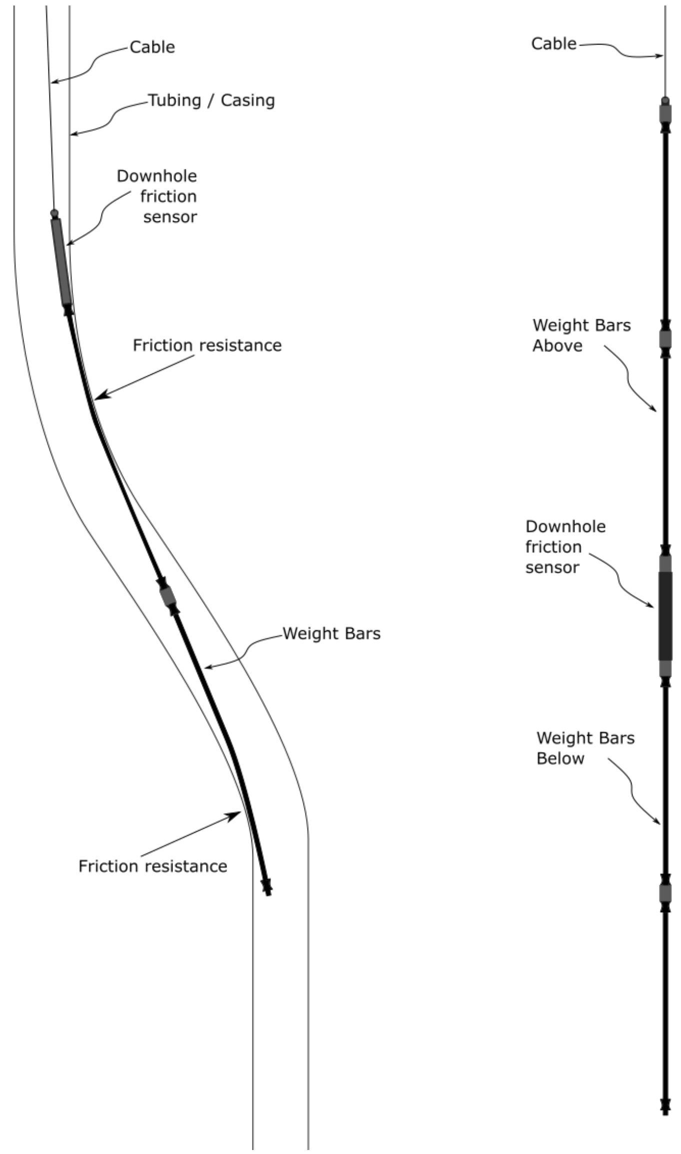

Figure 7: The concept of measuring friction over the entire wellbore at surface can be applied to a shorter rod section, traveling through the wellbore. The general self-contained sensing device for load and position can be placed in a downhole tool configuration where a length of weight bars are attached below (and possibly above) to sense friction as the tool is traveling through the wellbore. This provides a more localized measurement of friction compared to strict surface measurements. With weight bars below, friction can only be adequately sensed when the tool is pulled upwards. With a combination of weight bars above and below, friction acting on the lower weight bars can impart a compressive force on the load-cell. This allows friction to be sensed when the tool is traveling in either direction.