

“Field Lubricity Measurements Correlate with Improved Performance of Novel Water-Based Drilling Fluid”

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Abstract

A significant function of drilling fluids is reduction of frictional forces between the wellbore and the drill string. New techniques in drilling and completions are being used to drill horizontal wells in unconventional resources. Because these frictional forces can potentially limit the lateral length of a well, it is especially important to manage friction to avoid excessive torque and drag on the drill string. A high-performance water based fluid has been developed that reduces torque and drag to levels normally associated with non-aqueous fluids (NAFs).

A lubricity tester is often used to evaluate and predict the impact made from the use of a drilling fluid additive on friction. The most common tester, the Fann or OFITE Model 212, is normally used in a laboratory setting. This EP (Extreme Pressure) and Lubricity Tester is designed to simulate contact between a drill string and casing and consists of a rotating ring and stationary block, which are immersed in the drilling fluid. Since an exact load under wellbore conditions is hard to determine, typically fixed levels of contact forces are used.

While the EP and Lubricity Tester has been used in drilling fluid laboratories for many years, it has not been used as an instrument in the field on a regular basis until now. When the results of lubricity tests are measured and reported daily, the fluid can be modified with additives to maintain a target Coefficient of Friction, or CoF. Because fluid lubricity is affected by changing drilling fluid properties and wellbore conditions, infrequent laboratory lubricity tests provide little benefit, whereas field measurements made on a regular basis can help to ensure that the lubricity of the fluid stays on target. Regular field measurements also allow for detailed statistical analysis of the lubricity and its relationship to other fluid properties.

Controlling the drilling fluid lubricity within specified ranges and comparing the CoF to wellbore torque and drag achieves the results required of a high-performance fluid in critical applications. Post-well analysis with industry-accepted software can be used to find a corresponding wellbore friction factor on the final casing run. In this study, over 50 casing runs made with the high-performance drilling fluid were analyzed and correlated with the measured CoF. By doing so, the benefits of the high-performance water based fluid system could be quantified and its performance optimized for future applications.

Introduction

With the explosive growth of drilling into unconventional shale plays, operators have found that it is imperative to have an effective solution to manage the frictional forces seen in long horizontal laterals. Although conventional NAFs (oil-based and synthetic-based drilling fluids) usually provide sufficient lubricity, they also have significant disadvantages, especially high cost, expensive infrastructure, and growing environmental concerns. To manage the frictional forces experienced without using NAFs, a high performance water-based fluid was developed that focuses on reducing friction in long laterals.

The concepts associated with friction have been explored by scientists including da Vinci and Coulomb.¹ One useful parameter, the coefficient of friction (CoF), is a unitless number that serves to indicate the mechanical interaction between two surfaces. The static CoF is the ratio of the force required to initiate movement to the normal force holding the surfaces together. The kinetic CoF is the ratio of the force required to continuously move the surfaces to the normal force holding the surfaces together. Generally, it is the kinetic CoF that is measured and is thought to provide a measure of the frictional forces encountered while drilling ahead. When the contact surfaces are immersed in a fluid, such as the drilling fluid, the force required to move the surfaces is usually lower. Thus the drilling fluid acts to lubricate the drillstring. The reduction in CoF provided by the drilling fluid is a function of fluid composition. CoFs measured for water-based drilling fluids generally range from 0.15 to 0.45, but typically vary from 0.20 to 0.28. CoFs measured for NAFs generally range from 0.05 to 0.15, but typically vary from 0.07 to 0.14.

The lower the CoF, the easier it is to initiate or sustain movement of the two surfaces. In oil and gas well drilling, a reduced CoF will allow an operator to easily move and rotate the drill string in the wellbore. Every well encounters losses of transitional power to drill the wellbore. This occurs whether the well is directional or vertical. These losses of power are usually lumped together and labeled torque and drag and combined in the term “friction factor.” The friction factor and the CoF are thought to track each other. Overcoming some of the negative forces exerted on a drill string while drilling a well can provide better weight transfer to the bit and increase the rate of penetration. Once the well is complete, the power from the drilling rig must overcome the axial forces to retrieve the pipe from the hole. Reducing the friction factor can result in longer laterals; less expensive equipment, reduced wear on tools, reduced casing wear, increased tool life, and reduced vibration.

CoFs can be measured with devices as simple as a sliding block on an inclined plane to high pressure/temperature systems which have the capability of measuring effects of solid and liquid additives and periodically replenishing the additive between the contact surfaces. In this study, CoF measurements were made in the field with a simple ambient pressure and temperature device that measures the force required to maintain rotation of a steel ring in contact with a steel block immersed in the drilling fluid. Lubricity tests were conducted on 50 wells, and the results were compared with friction factors derived from torque and drag data collected while running casing. The latter were determined using industry-accepted torque and drag software. The analysis results in a friction factor that can be compared to industry-accepted values as well as used for design purposes in well planning.

Reducing Friction

There have been numerous mechanical methods proposed to reduce frictional forces in wellbores. While the advances in mechanical tools to reduce friction have proven successful, adding this hardware can increase risk from mechanical failure or change the flow pattern and increase the risk for packing off the annulus with drilled cuttings. In addition, most of these aids are not available when the casing is run in the wellbore. Since this analysis utilizes data from casing runs without mechanical aids, their effect cannot be investigated.

Additions to drilling fluids to reduce the frictional forces that are present at contact points between the well bore and drill pipe have mixed success. Solid materials like beads made from glass or plastic are used with the idea that the beads act essentially as ball bearings between the drill pipe and the wellbore. Most successes with solid materials have been in horizontal wells using smooth, hard materials. However, size degradation of the beads from high speed ejection through bit nozzles and grinding between the drill string and casing or open hole can be

problematic, as will the increase in surface area of the solids.. Drilling beads add to the fluid expense, and in most cases a significant fraction is removed by solids control equipment at the surface.

Liquid lubricants added to drilling fluid have successfully achieved a reduction in torque and drag but effects are generally short lived and or affect the mud properties. Most effective use has been spot applications and slug treatments on an as needed basis for temporary relief. This allows the lubricant to effectively wet the surface and maintain a film with some strength. However, the effect is fleeting, because the film strength is usually not great enough to withstand the large forces exerted between the drill string and casing or open hole. Furthermore, liquid lubricants generally lose their effectiveness as they are increasingly emulsified by shear or by chemical additions needed to maintain drilling fluid properties.²

With the advent of extended reach horizontal wells, it became increasingly clear that water-based drilling fluids would need to undergo a step change in lubricity. Because of the limitations of solids and liquid lubricants, it was decided to focus on developing a WBM that had an intrinsically low CoF and possessed some of the other attributes of NAFs, especially high levels of shale inhibition. Thus, the development efforts focused on a high-performance (highly inhibitive, highly lubricious) WBM. Furthermore, since extended reach wells are becoming increasingly deeper, the drilling fluid would also need to be rugged and versatile to handle unforgiving environments like elevated temperatures and high fluid densities. A newly developed clay-free polymer fluid with a liquid lubricant was designed to resist harsh environments and still perform equivalently to or outperform conventional NAFs.³ This high-performance water-based mud enhanced with the liquid lubricant was designed to provide greater than normal film strength and resist excessive emulsification. Since its introduction, this high-performance WBM has been used on over a thousand wells.

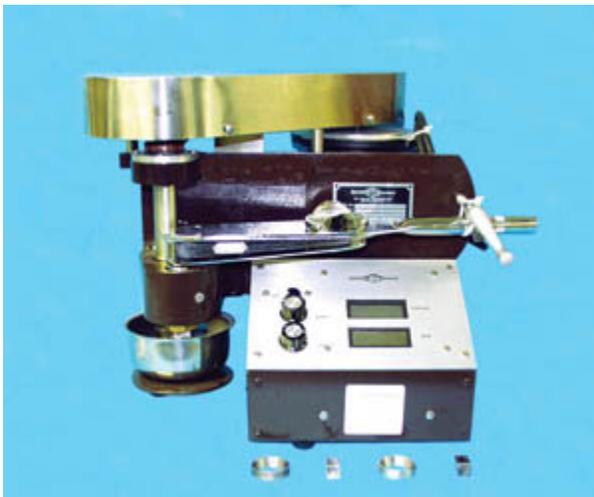


Figure 1. OFITE 112 EP & Lubricity Tester

Onsite measurements of CoF of the high-performance water-based drilling fluid were made with the OFITE 212 EP (Extreme Pressure) and Lubricity Tester (see Fig. 1). These were conducted in Lubricity Test mode by measuring the amount of force required to continuously rotate a hardened steel ring in contact with a hardened steel block while immersed in the high-performance WBM.

Establishing Measurement Criteria

A comprehensive assessment of 50 wells drilled with the high-performance water-based fluid was randomly chosen from a data set of over 100 wells. A program to obtain data from casing runs for analysis was established in

2011. This data is used with industry-accepted software⁴ to analyze the casing runs to determine an equivalent wellbore friction factor. The information obtained includes CoF and friction factor, which provides a basis for establishing system performance and future fluid property goals. These wells encompass regions in the United States where the high-performance fluid has been used. Every well is unique in that there is variability in lateral lengths, build angles, formations, drilling fluid, etc. As expected these inputs affect the wellbore friction as evidenced by the hook loads when running casing. Under ideal circumstances, the friction factor should be independent of the depth, well path, casing size/weight and formation.

In most analyses, two friction factors are utilized, one for the cased portion of the hole and one for the open hole section. This analysis used a single friction factor for both casing and open hole. This is an acceptable simplification because the bulk of the frictional forces in horizontal wells are found in the build and lateral sections, which are open hole. Table 1 gives typical values used for friction factor for various types of drilling fluids. The values given for the “high-performance water-based” system analyzed for this work of 0.10 – 0.30 will be discussed at length later. Typical values of CoF for steel on steel are also given in Table 1.

Table 1. Typical Friction Factors and CoFs Used in Modeling Torque and Drag

Drilling Fluid	Open Hole Friction Factor⁴	Steel on Steel Coefficient of Friction (CoF)
Air	0.40 – 0.60	--
Foam Water-Based	0.35 – 0.55	--
Lignosulfonate Water-Based	0.20 – 0.30	0.20 – 0.28
Polymer Water-Based	0.20 – 0.30	0.20 – 0.28
Oil-Based	0.15 – 0.20	0.07 – 0.13
High-Performance Water-Based	0.10 – 0.30	0.04 – 0.10

The protocol followed for the lubricity tests included rotation of the test ring at 60 rpm and application of 150 in-lb torque to the block, which generated 720 psi between the two steel surfaces. The surfaces are a hardened steel block and a hardened rotating steel Timken ring. Though the use of a steel block does not exactly represent the wellbore, it reduces variability and increases reproducibility of the measurements. Though the CoF observed for steel on rock is expected to be higher than for steel on steel, the trends are expected to be similar. T.C. Mondshine found in his experimental lubricity tests that many lubricants which performed well in lab-built fluids did not perform as well in the field.⁵ Once contaminants and mud additives (solids, crude, emulsifiers, thinners, etc.) were incorporated into the drilling fluid, these lubricants were rendered less effective. The high-performance drilling fluid used in the wells of this study is unique in that the mud lubricity is maintained fairly well throughout the drilling process. This was proven by recording similar values of the mud CoF over extended periods of time using the EP and Lubricity Tester. Nevertheless, as will be shown below, solid additives like lost circulation materials (LCM) can still affect the friction factor without showing a similar effect on the CoF, a phenomenon that we believe is an artifact of the EP and Lubricity Tester.

In the field applications used for this study, CoF was measured as part of every mud check throughout the interval where the high-performance drilling fluid was being used. The CoF values reported in Tables 2, 3, and 5 are averages over the high-performance mud interval. The CoFs measured during the casing runs are also reported.

The friction factor is calculated from the force required to move the pipe up and down within the wellbore. When running casing, this is done during the collection of the pick-up and slack-off loads. Along with these data, casing size, type, weight, standoff devices, and the surveys for the well path are used to model the casing run. This information is entered into the computer modeling software to obtain a friction factor that generates curves that model closely the actual pick-up and slack-off load data. The output of the software is a graph relating the axial loads

required to move the string (see Figs. 5-7). Slack-off values are considered to be most reliable for obtaining friction factors due to the fact that many times the casing is not fully picked up when running casing and may only be picked up enough to release the casing slips.

Friction Factor and Lubricity Data Analysis

The aim of this statistical analysis was to determine the significance of mud lubricity and the impact it has on the friction factor in the wellbore while running casing. In Table 2 and Fig. 2 below, it is seen that, on average, the resulting friction factor with the high-performance fluid was 0.21.

Table 2. Friction Factor and CoFs for Fifty-Well Data Set

	Friction Factor	Average CoF	CoF while Running Casing
Average	0.21	0.11	0.09
N	50	50	50
Standard Deviation	0.07	0.03	0.03
Mode	0.30	0.10	0.10
Median	0.20	0.11	0.09
Minimum	0.10	0.05	0.04
Maximum	0.30	0.19	0.19

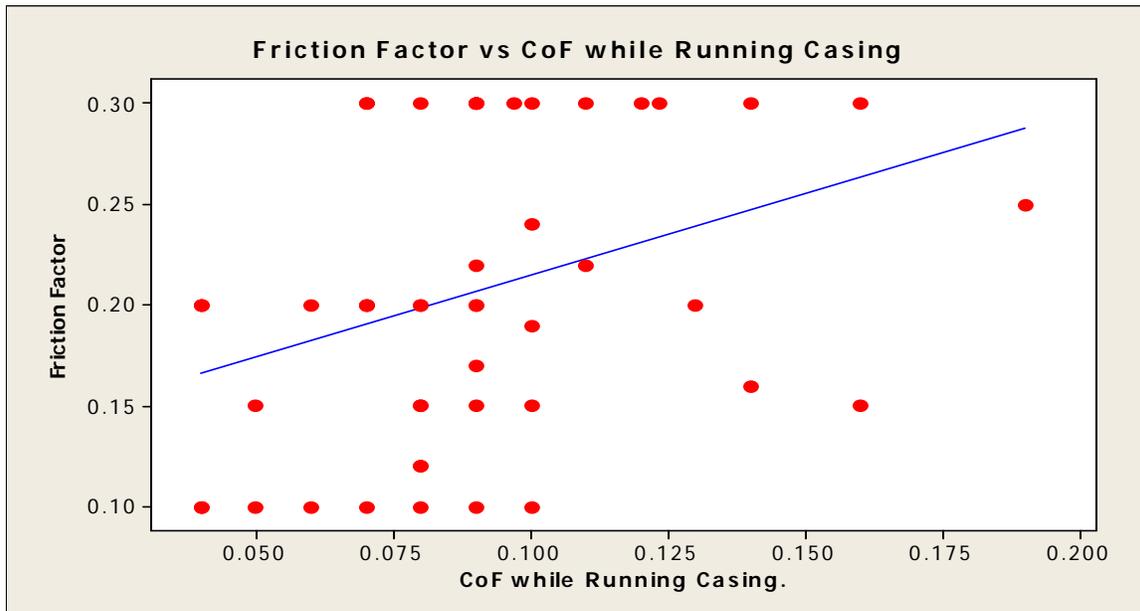


Figure 2. Friction Factor vs. CoF in the Open Hole (Wells with and without LCM). Note that some of the symbols represent two data points.

When a scatter plot of the data is examined, there does not appear to be a strong correlation of CoF with friction factor. This is confirmed with statistical analysis of the 50-well data. Even though on average the friction factor is nearly the same as is typical for NAFs (see Table 1), the spread between 0.10 and 0.30 suggests caution is needed if one were to design wells on the

basis of the average friction factor. Another way of describing this situation would be that if a design factor of 0.20 had been used, on 38% of the wells the friction factor would exceed the design factor. If achieving a 0.20 friction factor or less on the casing run were critical to success of the well, this would not be acceptable. It should be noted that for all the wells in the data set, casing was run successfully to bottom, so the higher friction factors experienced were not detrimental to well performance.

Discussions with field personnel suggested that at least some of the variability might be associated with lost circulation material (LCM), which was carried in half of the wells. Consequently, the wells drilled without LCM were re-analyzed in the same manner. The results are shown in Table 3 and Fig. 3. The average friction factor for these wells is 25% less than the data for all 50 wells, and the standard deviation for the friction factor is almost half of the value of that for the 50-well data set.

Table 3. Friction Factor and CoFs for Wells without LCM

	Friction Factor	Average Lubricity	While running casing
Average	0.15	0.10	0.08
N	25	25	25
Stand Deviation	0.04	0.04	0.03
Mode	0.20	0.09	0.08
Median	0.15	0.11	0.08
Minimum	0.10	0.05	0.040
Maximum	0.22	0.18	0.16

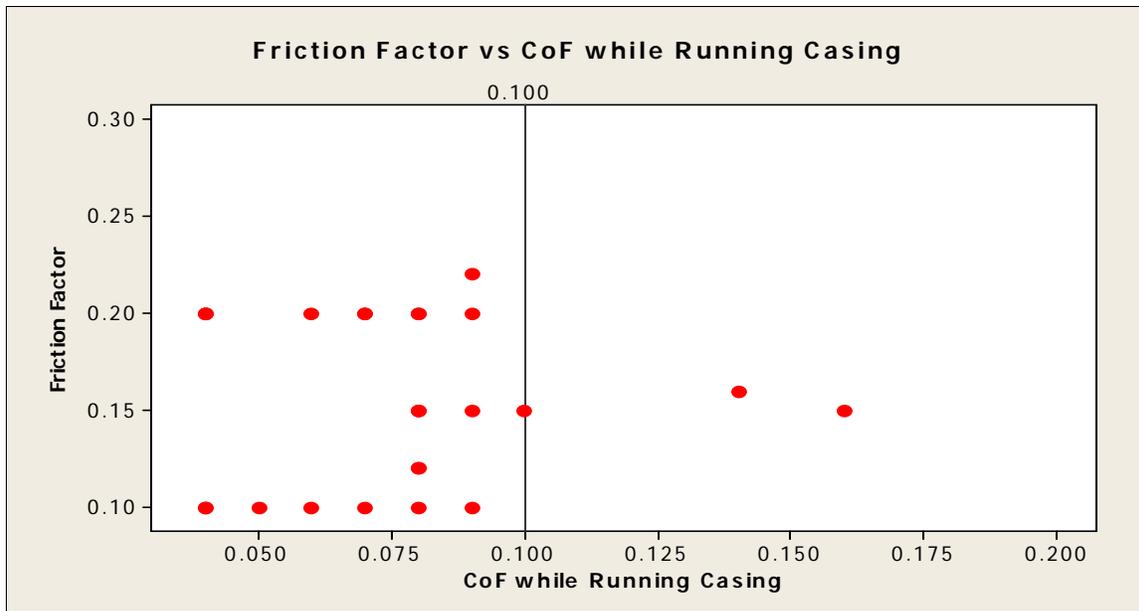


Figure 3. Friction Factor vs. CoF in the Open Hole (Wells without LCM). Note that some of the symbols represent two data points.

Removing wells in which LCM was used drastically reduces variability in the friction factor. It also suggests that setting a specification for CoF while running casing in the absence of LCM is possible. If the CoF were specified to be 0.10 or less, the friction factor without LCM would be

0.20 or less most of the time. Indeed, 96% of the wells drilled without LCM would meet these criteria. It is interesting to note that the specification of 0.10 or less had informally evolved as a design criterion for many of the wells drilled with the high-performance fluid. The data described here support that experience-derived “rule of thumb.”

Table 4 below lists some of the main variables of the wells in the data set. Not only did the base drilling fluid vary, but also mud density, concentration of lubricant (drilling performance enhancer, or DPE), well depth and lateral length. The high-performance WBM also used various types of shale inhibitors.

Table 4. General Well Information for Fifty-Well Data Set

Mud Description	High-performance WBM with drilling performance enhancer (DPE) ranging from 1.5 to 4 vol %, with inhibition as required Field brine with DPE ranging up to 4 vol %
Shale Inhibitor in high-performance WBM	Sodium chloride Potassium silicate Potassium carbonate Amine compounds Asphaltic materials Note: Selection and concentration depend on the application requirements
Mud Density	8.5 to 16.3 ppg (1.02 to 1.96 SG)
True Vertical Depth	6,500 to 14,500 ft (1,980 to 4,420 m)
Measured Depth	10,500 ft to 20,300 ft (3,200 to 6,200 m)
Lateral Length	3,500 to 9,600 ft (1,070 to 2,930 m)

Table 5 shows the friction factor, CoF, dog leg severity, tortuosity, and lost circulation material concentration used for the 50-well data set. The data are conditionally formatted with the smaller more desirable values in green graduated to the higher, less desirable values in red. There does not seem to be any relationship between friction factor and the survey-derived data. This indicates that the friction factor as determined from the modeling software is independent of the wellbore path and its variability. Correlation analysis of the survey data and friction factor confirms this.

Table 5. Fifty Well Dataset, Conditionally Formatted

Friction Factor	CoF while running casing	Well	Average CoF	Max Dogleg Severity %/100ft	Average Dogleg Severity in build %/100ft	Difference of Max to average Dogleg severity	Average absolute Tortuosity %/100ft	LCM while running casing lb/bbl	Field
0.200	0.040	1	0.053	19.74	9.65	10.10	0.73	0.00	Region 1
0.100	0.050	2	0.050	10.09	7.30	2.79	0.83	0.00	Region 1
0.100	0.040	3	0.052	17.98	10.06	7.92	0.80	0.00	Region 1
0.100	0.040	4	0.065	19.74	8.37	11.37	0.75	0.00	Region 1
0.300	0.110	5	0.108	13.78	7.78	6.00	1.13	3.00	Region 2
0.150	0.050	6	0.159	10.04	6.85	3.19	0.82	5.00	Region 2
0.150	0.080	7	0.179	10.93	6.94	3.99	1.13	0.00	Region 2
0.100	0.100	8	0.156	11.55	7.26	4.29	1.14	5.00	Region 2
0.300	0.080	9	0.099	12.80	8.62	4.18	1.23	2.00	Region 2
0.150	0.100	10	0.158	12.26	8.30	3.96	1.11	7.00	Region 2
0.100	0.090	11	0.133	10.93	8.63	2.30	0.89	4.00	Region 2
0.200	0.070	12	0.143	11.31	7.70	3.61	1.01	0.00	Region 2
0.300	0.070	13	0.104	11.20	6.77	4.43	1.09	4.00	Region 2
0.200	0.070	14	0.156	11.57	7.27	4.30	0.94	0.00	Region 2
0.300	0.123	15	0.174	11.06	7.09	3.97	1.31	7.00	Region 2
0.200	0.130	16	0.125	10.73	7.95	2.78	1.23	6.00	Region 2
0.150	0.080	17	0.120	11.03	7.49	3.54	1.29	0.00	Region 2
0.100	0.070	18	0.089	14.21	8.49	5.72	0.87	0.00	Region 2
0.120	0.080	19	0.109	13.47	9.43	4.04	1.56	0.00	Region 2
0.220	0.090	20	0.089	15.97	9.83	6.14	1.30	0.00	Region 2
0.240	0.100	21	0.107	12.74	6.84	5.90	1.26	0.00	Region 2
0.300	0.100	22	0.109	24.32	7.86	16.46	1.00	4.00	Region 2
0.200	0.090	23	0.093	11.22	7.49	3.73	1.19	0.50	Region 2
0.170	0.090	24	0.100	19.29	8.61	10.68	0.93	4.00	Region 2
0.300	0.090	25	0.090	11.95	7.56	4.39	1.03	2.00	Region 2
0.300	0.090	26	0.109	12.07	7.19	4.88	1.39	1.00	Region 2
0.300	0.120	27	0.134	14.55	6.65	7.90	1.31	8.00	Region 2
0.160	0.140	28	0.128	12.38	7.82	4.56	1.05	0.00	Region 2
0.300	0.090	29	0.101	13.40	7.46	5.94	1.06	1.00	Region 2
0.200	0.080	30	0.107	11.60	8.35	3.25	1.11	0.00	Region 2
0.100	0.080	31	0.116	13.81	8.63	5.18	1.31	0.00	Region 2
0.300	0.090	32	0.098	10.63	7.12	3.51	0.89	7.00	Region 2
0.190	0.100	33	0.100	12.97	7.23	5.74	1.50	1.50	Region 2
0.120	0.080	34	0.118	14.06	7.41	6.65	1.14	1.00	Region 2
0.200	0.070	35	0.068	10.47	8.43	2.04	0.95	0.00	Region 2
0.220	0.110	36	0.151	10.32	7.23	3.09	1.05	3.00	Region 2
0.300	0.160	37	0.171	13.61	7.15	6.46	1.20	5.00	Region 2
0.250	0.190	38	0.191	13.06	7.20	5.86	1.40	8.00	Region 2
0.300	0.097	39	0.127	12.01	7.00	5.01	1.19	6.00	Region 2
0.300	0.070	40	0.135	10.72	7.44	3.28	0.94	2.00	Region 2
0.300	0.090	41	0.108	11.89	6.98	4.91	1.17	4.00	Region 2
0.300	0.140	42	0.111	12.00	7.23	4.77	1.25	6.00	Region 2
0.200	0.080	43	0.106	15.07	10.70	4.37	0.98	0.00	Region 3
0.200	0.060	44	0.057	17.82	8.99	8.83	1.05	0.00	Region 3
0.150	0.090	45	0.107	18.75	10.48	8.27	1.03	0.00	Region 4
0.100	0.060	46	0.070	14.63	7.92	6.71	0.65	0.00	Region 5
0.200	0.040	47	0.047	15.76	9.93	5.83	0.92	0.00	Region 6
0.200	0.040	48	0.096	12.81	7.42	5.39	1.10	0.00	Region 6
0.200	0.090	49	0.089	14.21	10.89	3.32	1.17	0.00	Region 7
0.150	0.160	50	0.137	13.36	9.52	3.84	1.15	0.00	Region 7

Reducing Variability When Using LCM

The variability associated with the use of LCM does suggest that if well designs change, particularly to longer laterals, steps should be taken to reduce the variability of the friction factor. Possible actions could include evaluation of LCM concentration effect on friction factor, removal of the LCM prior to running casing, and alternative LCM materials. An alternative is to use a different lubricity tester. It is well known that the action involved in measuring CoF with the EP and Lubricity Tester sweeps solids away from the contact surfaces. Consequently, the effects of solids larger than a few microns in size are not observed. Other lubricity test devices are available which retain the solids in the space between the contact surfaces. These have been shown to be useful for measuring effects of solid lubricants on CoF.⁶

While the high-performance fluid with LCM continues to be used successfully in this area and is resulting in reduced well costs, efforts to identify sources of variability are needed in anticipation of future changes to well design. Closely working with field personnel, including fluid service technicians, drilling fluid engineering supervisors and operator's representatives, can help to improve performance, of course. With this technical support, sources of variability can be identified and uncertainties can be reduced. A robust program of monitoring performance, determining and communicating lessons learned, and training in analysis techniques has been implemented to continue to improve performance through evolution of the fluid technology.

Improving Performance While Drilling

Reducing the axial drag and the rotational torque from contact due to the weight of the pipe against the wellbore will enable drilling longer horizontal laterals. Since the longer horizontals expose more formation, there is a tendency to maximize lateral length. If the torque limit on the drill string is approached, then drilling cannot proceed without greatly increasing the risk of drillstring failure. Modeling these forces is important to prevent problems and to predict the results of all operations associated with the wellbore.⁷ Relating results from a field instrument can help with evaluation of fluid-treating strategies, such as treatment with an appropriate lubricant like the drilling performance enhancer (DPE) designed for the high-performance water-based drilling fluid.

The impact that the DPE has on the friction factor can be discerned by analyzing the on bottom and off bottom torque. In the example shown in Fig. 4, the lateral of a well in Area 1 that was being drilled with produced brine began experiencing increasing torque. By the time drilling had progressed to 13,600 ft (4,150 m), the rate of torque increase was such that it was obvious that the torque limit of the drill string would be exceeded before reaching planned total depth. The base CoF of the brine was 0.12. DPE was added at that time in 1 vol % increments. With the initial addition of DPE, the CoF was reduced to 0.04, but shortly thereafter began increasing and reached 0.05 by the time the next addition was made. These periodic treatments proceeded until the nominal DPE concentration (assuming no depletion) reached 4 vol%. At this time, the torque remained at a sustained low level until reaching a total measured depth of over 20,000 ft (6,100 m). The torque limit on the drill string was not reached. Use of produced brine to replace NAFs as drilling fluids has been successful in this application at least in part because of the lubricant DFE.

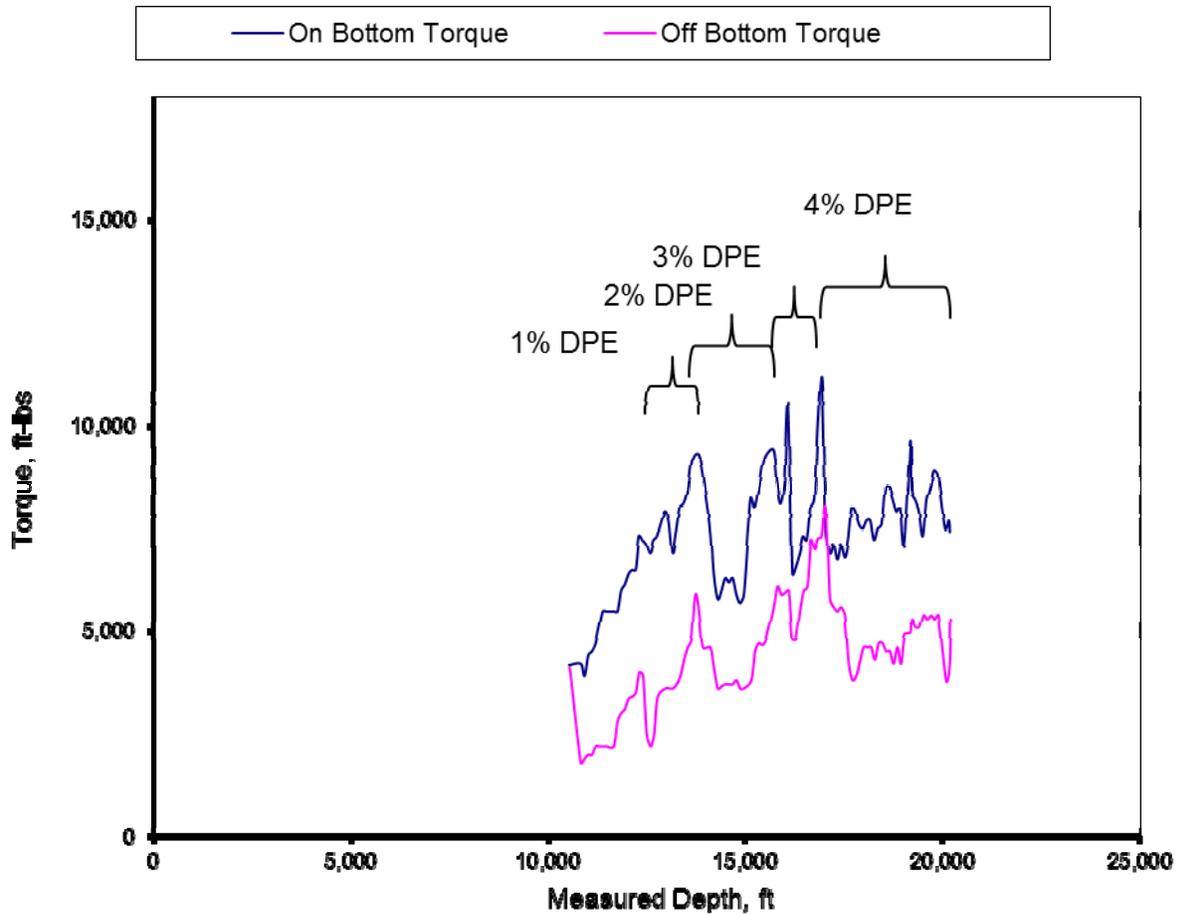


Figure 4. Sustained Torque Reduction While Drilling

Example Casing Runs

After drilling the well discussed in the previous section, a complete analysis of the casing run was carried out by recording the hook load after every 20 joints of casing. The hook load was then compared to a computer generated hook load with a 0.20 friction factor. Fig. 5 below is an example graphical representation of the data collected during the casing run. The "Actual Tripping Out" values are much lower than expected because the string was not picked up completely while running casing. The string was only picked up sufficiently to pull off of the slips. Correlation of the friction factor to the pickup weight is not possible since full pickup loads were not recorded and may not have occurred.

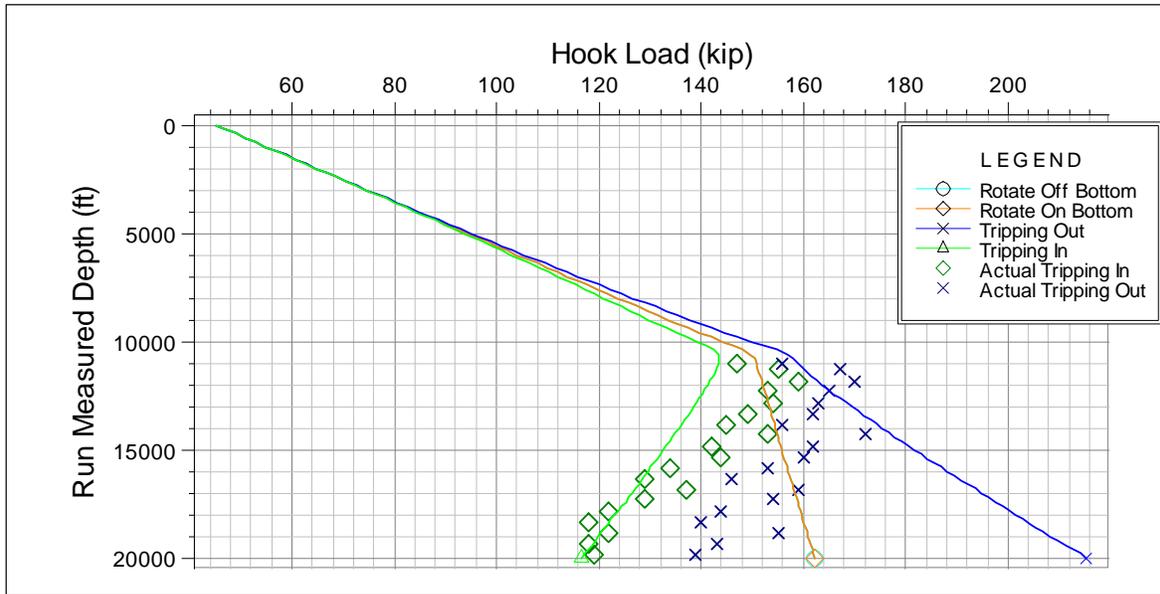


Figure 5. Region 1 Casing Run with a 0.20 Friction Factor

On wells using the high-performance fluid, a standard data collection process resulted in the data required for analysis of the casing run. Figs. 6 and 7 give results for two wells in Region 2. These show the typical results of the casing run analysis for a friction factor of 0.20 and 0.15. Other friction factors – both lower and higher – were also examined, but these two values appeared to show the closest matches between the Tripping In fitted curve and the Actual Tripping In data. Close examination of Figs. 6 and 7 shows that a friction factor of 0.15 is probably a better match of the fitted curve to the data than a friction factor of 0.20.

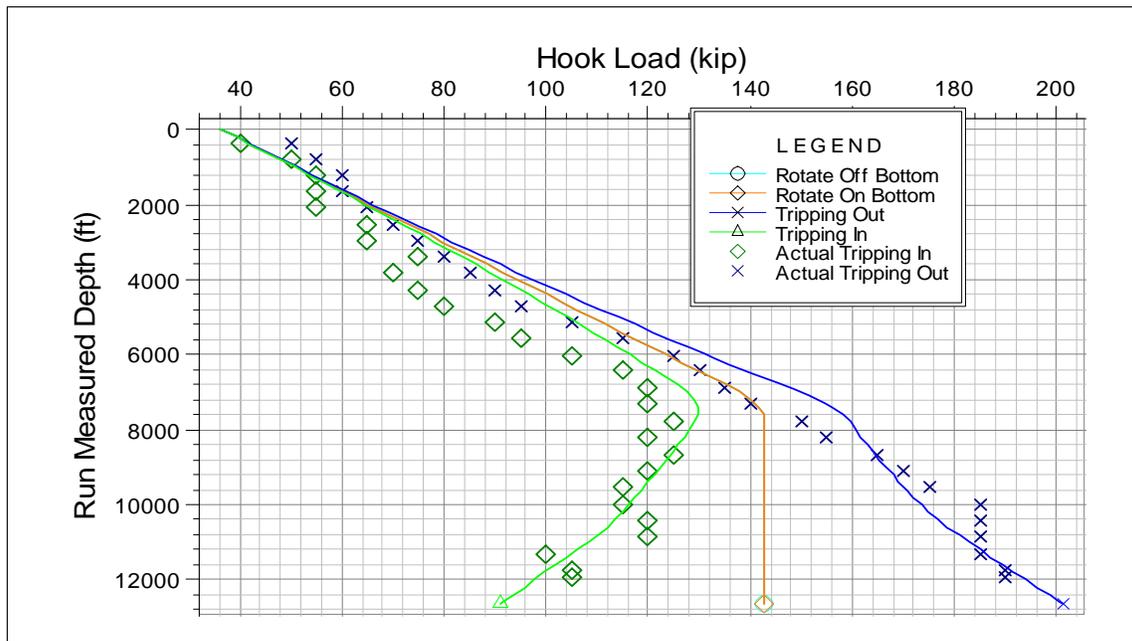


Figure 6. Region 2 Casing Run with a 0.20 Friction Factor

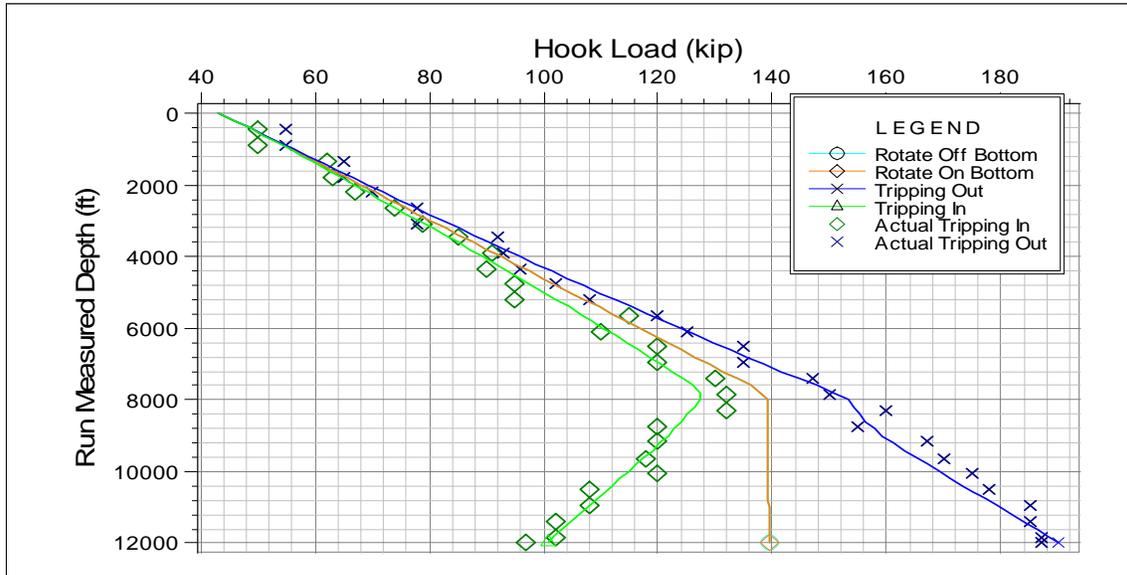


Figure 7. Region 2 Casing Run with a 0.15 Friction Factor

Conclusions

Wellbore friction is an important consideration in horizontal well design. Focusing on the casing running operations and evaluating their results provides a useful indicator of overall well success. Analyzing the results of a large number of successful wells, in this case 50, provided insight into the performance and confidence in predicting future results. Use of the high-performance water-based fluid developed for horizontal drilling resulted in performance on par with oil-based mud and other NAFs at considerable well cost savings.

The analysis of data from the 50 casing runs resulted in the following insights:

- Wells drilled with a novel high-performance drilling fluid showed some significant variability in friction factor, apparently a function of lost circulation material, although the average friction factor of 0.21 was similar to that of NAFs
- Analysis of the data from the 25 wells in which LCM was not used gave an average friction factor of 0.15, with 96% of the wells showing less than 0.20
- Studying the variability in torque and drag associated with casing runs can be useful to find ways to improve performance

The newly developed Drilling Performance Enhancer, DPE, can provide

- Sustained torque reduction while drilling
- Successful drilling of horizontal wells that normally require NAFs

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