HIGH-PERFORMANCE FLUID CONTRIBUTES TO IMPROVED DRILLING RESULTS IN UNCONVENTIONAL SANDSTONE FORMATION

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ABSTRACT

For many years one of the primary natural gas exploration and production targets in East Texas and West Lousiana has been the Cotton Valley (CV) Sands and associated subsections. The advent of new and successful technology for drilling horizontal wells have increased the return on investment to advantageous levels for this play. The Cotton Valley is a very abrasive, consolidated Jurassic-Cretaceous sandstone. When non-aqueous fluids (NAF) or conventional water-based fluid (WBF) systems are used in horizontal wells in this formation, abrasiveness combined with directional tortuosity and horizontal lateral lengths cause rates of penetration (ROPs) to suffer while torque and drag values increase to the point where drilling cannot be continued. The utilization of a high-performance water-based fluid (HP-WBF) system proves vital in meeting interval objectives while remaining cost-effective and environmentally friendly.

Primary fluid objectives in horizontal wells are typically very similar: help to maximize ROP, decrease torque and drag, stabilize the wellbore, and enhance wellbore cleaning efficiency. In an effort to improve drilling fluid effectiveness while maintaining consistent ROPs and manageable torque and drag values a number of fluid additives have been field tested in the CV horizontal wells with the goal of decreasing frictional forces. Examples include refined oil, sulfonated asphalts, graphite, and fine beads. All of these additions yield varying, inconsistent results. Using a newly developed high-performance fluid system, ROPs increase 20-50% as torque values decrease 20-50% simultaneously. The results using this systems approach show consistency, repeatability, and have proven to be cost effective.

Key factors influencing the necessity of a carefully and custom designed drilling fluid are hole size, casing design, drill string, bottom hole assembly, bit selection, and drilling fluid properties. The combined components of the well design help identify tangible measures of success. Average daily ROP and on-bottom torque are two drilling parameters identified as key performance indicators. Therefore, over the course of a given length of time ROP, torque values and other properties are monitored and recorded. After compiling and analyzing this the effectiveness of a high-performance fluid system can be determined and subsequently quantified. A case history analysis of over 30 horizontal Cotton Valley wells utilizing a high-performance fluid provides the basis for demonstrating the advantages and therefore the cost effectiveness of using this new fluid technology.

INTRODUCTION

A brief description of the Cotton Valley group will be given along with some previous concerns and known issues. A summary will be outlined from a selection of 30+ wells with several notable benchmarks identified. This will follow with a discussion outlining the lessons learned and any correlations observed. This case study illustrates a great application of new technology[1,2,3] implementation and execution for a hydrocarbon rich field plagued by problematic drilling and operational challenges. Key highlights include lower friction factors while running production casing, torque is lower and more manageable, and improved ROPs.

COTTON VALLEY GROUP

The Cotton Valley group is categorized in the Upper Jurassic and Lower Cretaceous chronostratigraphic systems[4]. It covers the region as illustrated in figure 1. It is deemed clastic consisting of sandstone, shale, and limestone[4]. Overall, it is considered moderately porous and variable in terms of permeablity[4]. Estimated porosity levels are in the 10-19% range and permeability ranges between 1-280 mD[4]. However, permeability as low as 0.1 mD has been encountered[5]. The Cotton Valley area in question is generally characterized as being a tight sand containing primarily natural gas and natural gas liquids[4]. The focus of this paper is on the lower permeability areas of the northwest corner of Louisiana.

The Cotton Valley group has been described as containing very abrasive drill solids that need to be meticulously controlled[6]. This has created situations where very expensive solids control treatments or preventatives had to be applied to the drilling fluid. The abrasive nature of the Cotton Valley has been detrimental to operational efficiency by causing poor ROP and bit life.

Since the late 1930's, the Cotton Valley formation has produced trillions of cubic feet of natural gas. Untapped recoverable reserves are estimated at greater than 150 Tcf in an undeveloped area greater than 8,600 square miles (2.2×10^{10} m^2). The average Estimated Ultimate Recovery (EUR) per well is around 1.5 Bcf[7]. For these reasons, the Cotton Valley group has proven to be a very desirable, yet challenging field for vertical natural gas exploration and production for many decades. In recent years an influx of horizontal well design enhancements has driven the renewed interest for an overall improvement in operational efficiency and fluids optimization for this area.

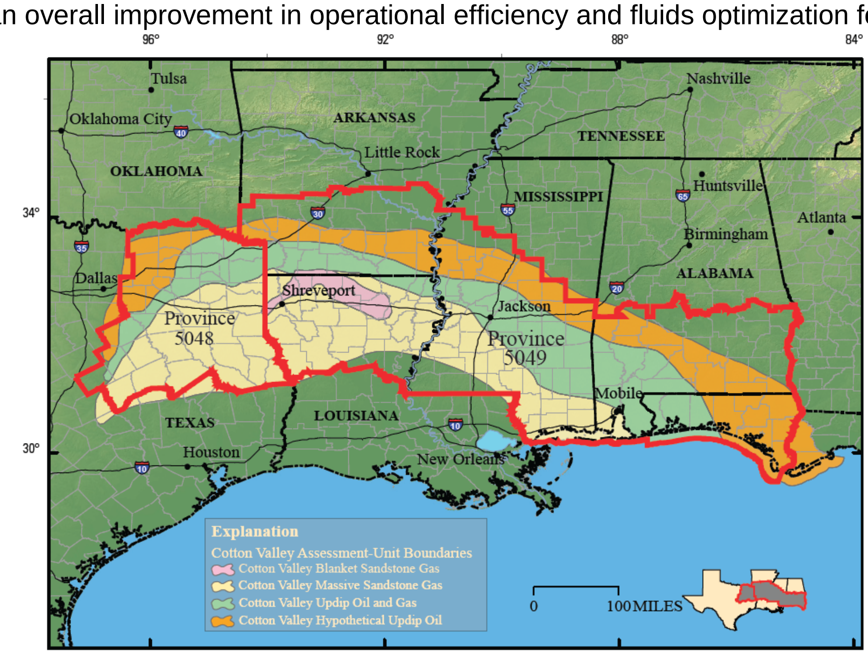

Fig. 1 Cotton Valley Group from reference 4

SHALE & GEOLOGICAL ANALYSIS

Shale samples analysed using a x-ray diffraction (XRD) for this group were found to be high in quartz and clays. The main clay observed in the sample ($^2/_3$ of the clay content) was illite.. Generally, the deeper the samples the more clay was found. Cation Exchange Capacities (CEC) indicated that these samples were not very reactive; the range was 3.3-15.5 meq/100g. The main exchangeable base is calcium.

The samples were measured for the specific area to be drilled. The results served as validation to what was generally known about the Cotton Valley Group[4]. The shale analysis supported that the area to be drilled was indeed a clastic sedimentary rock. In the specific location south of Shreveport, Louisiana where these wells have been drilled, the deeper formations with high clay content may be indicative of the shale formation that is underlying the strata of the Cotton Valley Group like the Bossier or Haynesville formation as shown in figure 2 below[8].

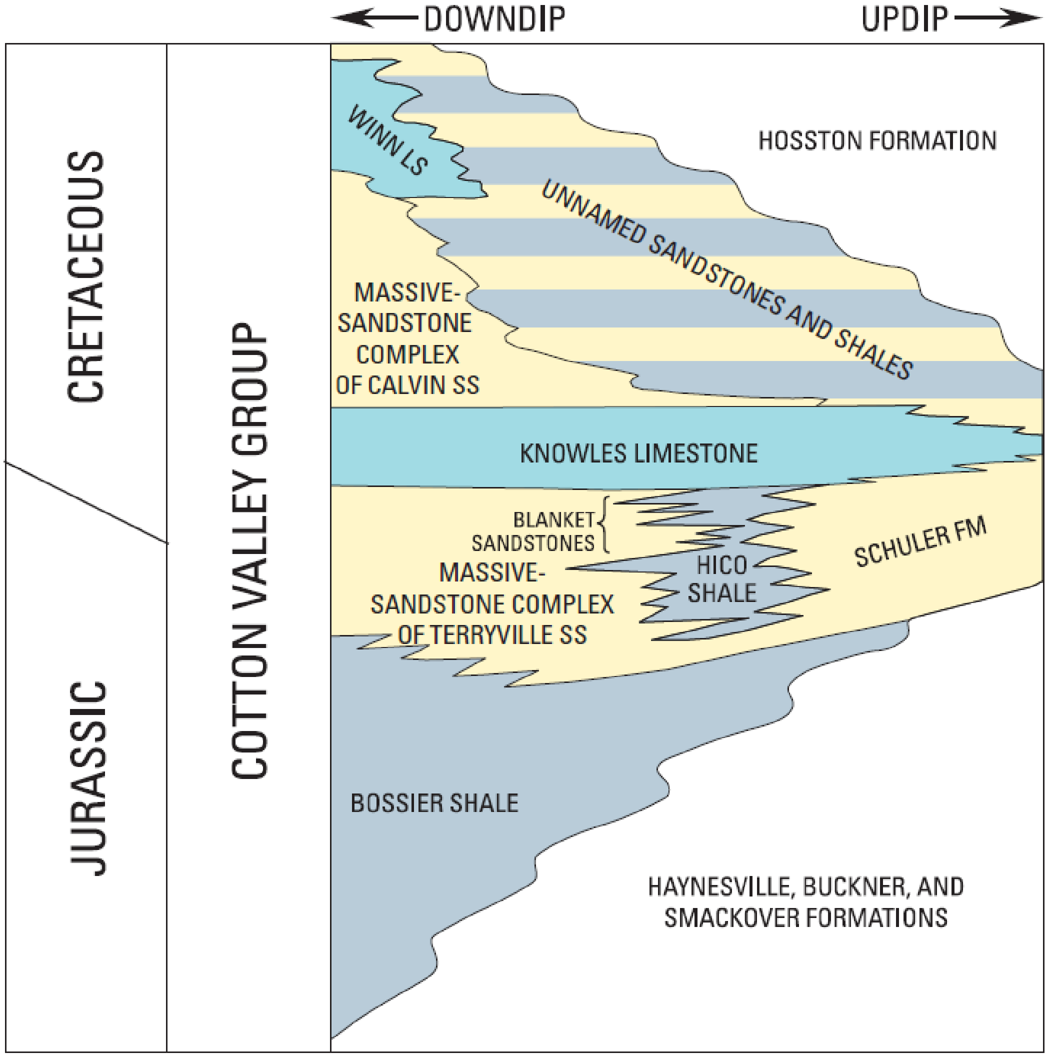

Fig. 2 Sedmintary and stratigraphic nomenclature of the Cotton Valley Group in North Lousiana from reference 8

WELL & CASING DESIGN

There are three typical well designs used throughout the Cotton Valley development area. The first consists of setting surface casing at or below a depth to meet state and local requirements. From this point, the well may be drilled utilizing an 8.75" hole size to total depth (TD) maintaining the same hole size through vertical, curve, and lateral. Typical vertical depth (TVD) of the well is 9,500-10,500 ft (2,896-3,200 m) and the measured depth (MD) 14,000-20,000 ft (4,267-6,096 m).

The second design is a modified version of the above description and consists of the same surface casing depth. This is followed by setting an intermediate string of casing to cover and protect saltwater injection zones that contain abnormal pressure (estimated to be > 3400 psi (23,442 kPa) or 0.56 psi/ft (12.7 kPa/m)). In this design, an intermediate casing string is cemented vertically around 6,000-9,000 ft (1,800-2,700 m) TVD and the production interval curve and lateral is drilled utilizing a 6.125" - 6.75" bit. Typical TVD of the lateral is 9,500-10,500 ft (2,896-3,200 m) and the MD 14,000-20,000 ft (4,267-6,096 m).

The third well design consists of a similar surface casing depth, followed by an intermediate string of casing cemented after the curve is drilled at an inclination of 80° - 90° and TVD of 9,500 – 10,500 ft (2,896-3,200 m). The lateral is then drilled with a 6.125" - 6.75" bit to a MD of 14,000-20,000 ft (4,267-6,096 m).

OFFSET REVIEW

Over the past five years, traditional drilling practices have been challenged in the Cotton Valley Group. In an effort to achieve maximized efficiency, conventional bentonite and lignite water based fluids (WBF) were tested with a multitude of additives. Such additives included refined oils, sulfonated asphalts, graphite, and beads. The results found inconsistent and unpredictable bit run lengths, poor ROPs, and unacceptable torque values.

In some cases, drilling to TD was not reached or was shortened because the total drilling cost exceeded the budget. Prolonged time spent on the well and/or mechanical limitations such as maximum torque on the drill string were the main causes for this outcome. As a result, these issues decreased the performance, efficiency, and return on investment (ROI) for operators.

Conversely, due to the success in other unconventional resource developments, non-aqueous fluids (NAF) were tested to address and improve ROP and torque issues. Surprisingly, the performance of NAFs was not as anticipated and turned out to be counterintuitive to most historical expectations. ROPs were equal to or less than conventional WBF systems. Consequently, drilling costs increased due to the base fluid's requirements, disposal, health & safety environment (HSE), and other ancillary costs.

The HP-WBF presented in this paper had been known to decrease time and costs in multiple situations[1,2,3,9]. The proposed system is clay free[1] which satisfies the desire to maintain a low solids fluid. The system's lubricating capability was shown to have a direct correlation with decreased friction factors which had beneficial results on the torque and drag[9].

DRILLING FLUID DESIGN

It has been well known that a low solids drilling fluid is the key component in limiting the detrimental effects (e.g. abrasitivity) to the drilling process for this particular area[6]. Traditional fluid design of conventional WBFs focused on maximizing the potential of torque reduction additives such as refined oil, asphalts, graphite, and bead products. Almost all fluids used lignite and bentonite as building blocks to maintain and control API fluid loss and rheological values. As previously demonstrated, wells could be drilled with these types of fluids, but overall system performance usually failed to meet well and/or interval goals. Torque values dictated well TD and drilling costs did not improve due to ROPs of 5-15 ft/hr (1.5-5 m/hr).

Once operators committed to a full commercialization horizontal drilling program for the Cotton Valley field, the focus shifted to optimization of all drilling aspects. The overall goal was to improve the total number of days and reduce well costs. Therefore, the necessity of a HP-WBF became imperative. Key performance indicators (KPIs) of fluid performance and critical fluid properties were identified as typical horizontal fluid objectives; such as, ROP maximization, torque & drag management, wellbore stabilization, and efficient hole cleaning capability. The KPIs were addressed individually while maintaining a simple and scientific approach to satisfy all requirements and minimize attention to non-essential parameters.

A clay-free polymer-based fluid system was selected to maximize ROP and help manage torque & drag[1,2,3,9]. A drilling performance enhancing additive was used to improve ROP and control torque[9]. Due to the low reactivity of the sandstone, primary wellbore stabilization was achieved through drilling with the appropriate mud density. Hole cleaning was addressed by utilization of a proprietary polymeric additive that provided rheological enhancement and fluid loss control[1,2,3]. All components of the fluid system were sustainable for the expected bottom-hole circulating temperatures of 230-260^{o}F (110-127^{o}C). Tables 1 & 2 below list a typical fluid formulation and target properties.

Tab. 1: HP Fluid Formulation Using Freshwater

High Performance Fluid Formulation using freshwater		
Additive	**Function**	**Concentration**
Polymeric Viscosifier	Rheology and Filtration	1 -2 ppb (3.8 – 7.6 kg/m^3)
Performance Enhancer	Friction Control	1 - 3% by vol
Xanthan Gum	Rheology Supplement	0.25 - 0.5 ppb (0.95 – 1.9 kg/m^3)
Sodium Hydroxide	Alkalinity Source	1 - 1.5 ppb (3.8 – 5.7 kg/m^3)
Fluid Conditioner	Conditioner	1 ppb (3.8 kg/m^3)
Barite	Weight Material	As Required

Tab. 2: Target Properties

Target Properties	
Density	10.0 - 11.0 ppg (1.20 – 1.32 s.g.)
Plastic Viscosity	< 15 cPs
Yield Point	12 - 25 lbf/100 ft^2 (6- 12 g/(100 cm^2))
API Filtrate	< 5 cc
pH	9.5 - 10.5
MBT	< 20 ppbe
LGS	< 6%, by volume

The outcome was a simple, yet customizable fluid system to effectively drill the Cotton Valley formation. As a result of using the HP-WBF, operators were able to drill longer laterals and reach deeper depths by increasing ROP and reducing the drilling costs.

OVERALL WELL SUMMARIES AND BENCHMARKS

The following paragraphs summarize and compare the well operations of over 30 subject wells using data gathered from daily operations with special attention on the total number of drilling days, ROP, and any available torque data.

Days, Depth, and ROP – Based on available offset data from horizontal Cotton Valley (HZ CV) wells, the HP-WBF outperformed the wells that used conventional WBFs or NAFs. The lateral drill time decreased by a weighted average of 12.3 days, or 49.5% with a rate change of 256 ft/day (78 m/day) or 243% increase in efficiency. The current benchmark (Q1 2015) is a lateral length of over 10,100 ft (3,079 m) and an average daily ROP of 772 ft/day (235 m/day).

A comparison of lateral length and average ROP is illustrated below. It demonstrates consistent and faster drill times and shows the ability to drill longer laterals. The average lateral length of different fluids is tabulated below:

Tab. 3 Different fluids

Fluid Type	Average Lateral Length
WBF	3,257 ft (993 m)
NAF	5,313 ft (1,619 m)
HP-WBF	4,964 ft (1,513 m)

The weighted average lateral length of WBF and NAF is 3,585 ft (1,093 m). It should be noted that only one NAF data point was available. Figures 3,4,5 illustrate how the HP-WBF enabled area operators to improve their drilling efficiency by reaching longer lateral lengths at a reduced rate of time with quantifiable results.

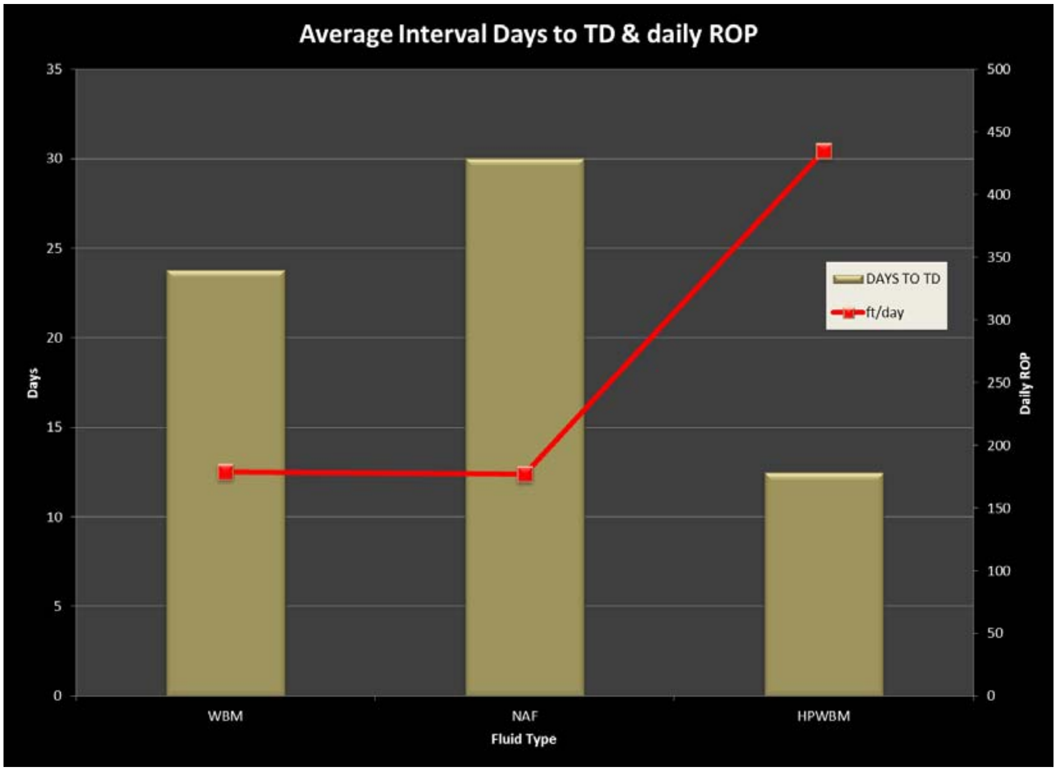

Fig. 3: Average Interval Days to TD % Daily ROP

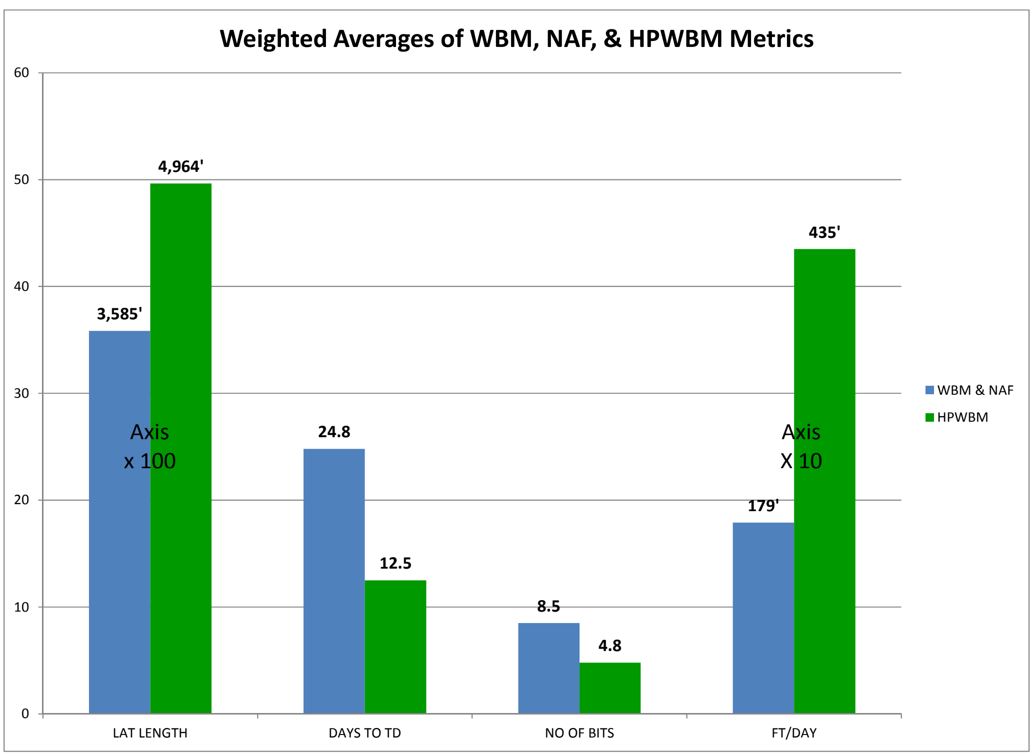

Fig. 4: Weighted Averages of WBF, NAF, HP-WBF Metrics

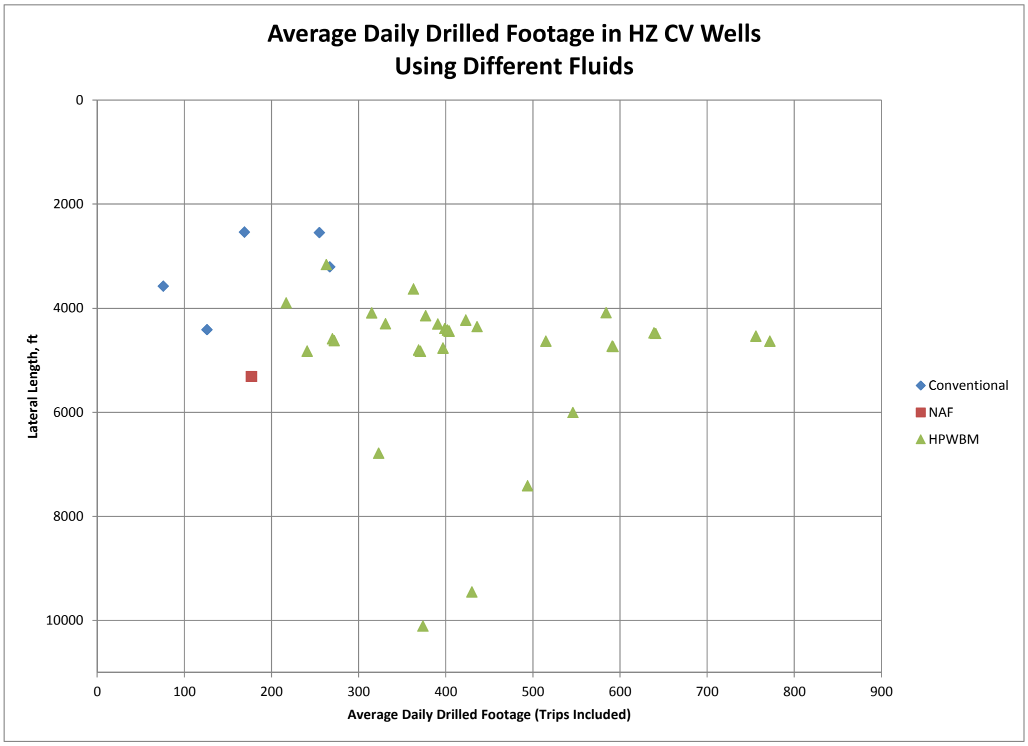

Fig. 5: Average Daily Drilled Footage in HZ CV Wells

The substantial increase in average daily ROP can be attributed to the utilization of a shear-thinning fluid with fewer solids. The synergetic effectiveness of a polymer and performance enhancer reduces frictional forces, provides necessary filtration control, and enhances rheological values. It should be noted that the bit design and selection was also a factor to achieve an increase in ROP. Nevertheless, when the HP-WBF was applied, an immediate daily ROP increase was observed before such applications were made. Also, note the NAF fluid well achieved less than 200 ft/day (61 m/day) which explains why so few wells have been drilled in this play with NAF.

<u>Torque Management</u> – One of the primary goals in the design of the adapted HP-WBF fluid system for the CV was the ability to manage torque (both on-bottom drilling torque and off-bottom rotating torque). Subsequently, another related goal was the ability to successfully set production casing on the bottom at TD of each well. To do this, casing frictional factors had to be within acceptable operational ranges for the size and strength of the casing.

A crucial component of the HP-WBF fluid system designed for the Cotton Valley is the performance enhancer which drastically reduces frictional forces imposed on the drill string. This is carried out while drilling, while off-bottom rotating or during clean-up cycles. It is added accordingly (if at all) based off of real-time torque values. Typically, the performance enhancer is added to the fluid system in a percent-by-volume concentration and results in a 20-50% reduction in torque. As part of the optimization process, the amount of performance enhancer is tracked and compared against multiple torque readings at TD of a well. Together WBF and NAF wells only had one data point available to represent these fluids. Lack of data from these wells encouraged the development of improved data gathering. A document was created to capture pertinent torque data for the CV wells. An example of this document is attached in the Appendix of this paper.

In some cases, when using a non-HP-WBF torque limitations were experienced before obtaining the anticipated TD. Using industry accepted modelling software; the TD was recalculated using the buckling trends correlating to the average friction factors of WBF. With the implementation of a HP-WBF, the on-bottom drilling torque values at TD fell within acceptable operating parameters. The hole geometry, bottom-hole assembly (BHA), and drill string were used as expected and did not require the applications of controlled drilling or a reduction of the weight-on-bit (WOB).

The on-bottom torque values allowed wells to reach new, farther total depths that were previously unattainable. Figure 6 represents on-bottom torque and lateral length of 31 wells using HP-WBF and one using a NAF. Conversely, figure 7 represents off-bottom torque at TD of the same subject wells and figure 8 represents off-bottom torque versus lateral length. Off-bottom torque data is not available for conventional WBF and NAF subject wells. Please note that off-bottom torque values are measured by recording the torque value while circulating at the drilling flow-rate and rotating at 60 rpm.

With the use of a HP-WBF the first 5,000 ft (1,524 m), 7,500 ft (2,286 m) and 10,000 ft (3,048 m) laterals were successfully drilled with production casing set and cemented at TD in the Cotton Valley. The ability to increase lateral length drastically changes the economics and performance metrics for operators. Previously, torque value limitations were exceeded and discouraged the planning and execution of extended-reach wells. Figure 9 illustrates the off-bottom torque value and percentage of performance enhancer in the fluid required to reach TD. The 6.125” and 6.75” wells represent the majority of the data points because they were the most common well design. The median percentage of performance enhancer was 1.9% with a corresponding lateral length of 5,107 ft (1,557 m) and an off-bottom torque of 7,400 lbf/ft (1,023 kgf/m).

As part of an on-going data collection program, off-bottom torque readings were collected throughout the production intervals to quantify and optimize the amount of lubricant required to meet interval objectives. After analysing data from over 30 wells, the best strategies to mitigate frictional forces were established for varying lateral lengths. One of the approaches was to maintain the performance enhancer at a concentration of 1.5-2.5% for lateral lengths up to 7,000 ft (2,134 m). For lateral lengths greater than 7,000 ft (2,134 m), the ideal concentration for the performance enhancer increases to 2.5-3.0% by volume.

Industry recognized modelling software was used to determine friction factors of the production string of casing. This led to a better understanding of the tubular modelling and future well planning. The casing friction factors were then plotted against operating parameters, fluid properties, and performance metrics to monitor and record success rate. This was also used to determine median and optimal fluid requirements. Accordingly, a database of reference points was established. Future wells can be compared for performance standards and quantitative analysis.

One important quantitative correlation discovered was the open hole friction factor association to the application of the performance enhancer. It was discovered that the median open hole friction factor while running production casing was 0.24 in wells with either a 6.125” or 6.75” wellbore. Using the same method the median open hole friction factor was 0.275 in an 8.75” wellbore. The friction factors were also correlated to the fluid parameters and well bore integrity. Figure 10 illustrates the relationship between friction factor and performance enhancer concentration.

Friction factors as low as 0.1 were achieved on some wells. In many cases, very tortuous wellbores were navigated to land casing on bottom; some with absolute tortuosity of 2°/100 ft (2^o/30 m) and dogleg severity of greater than 5°/100ft (5^o/30 m). It was also determined the off-bottom torque at TD can correlate and help predict open hole friction factors as illustrated in Figure 11.

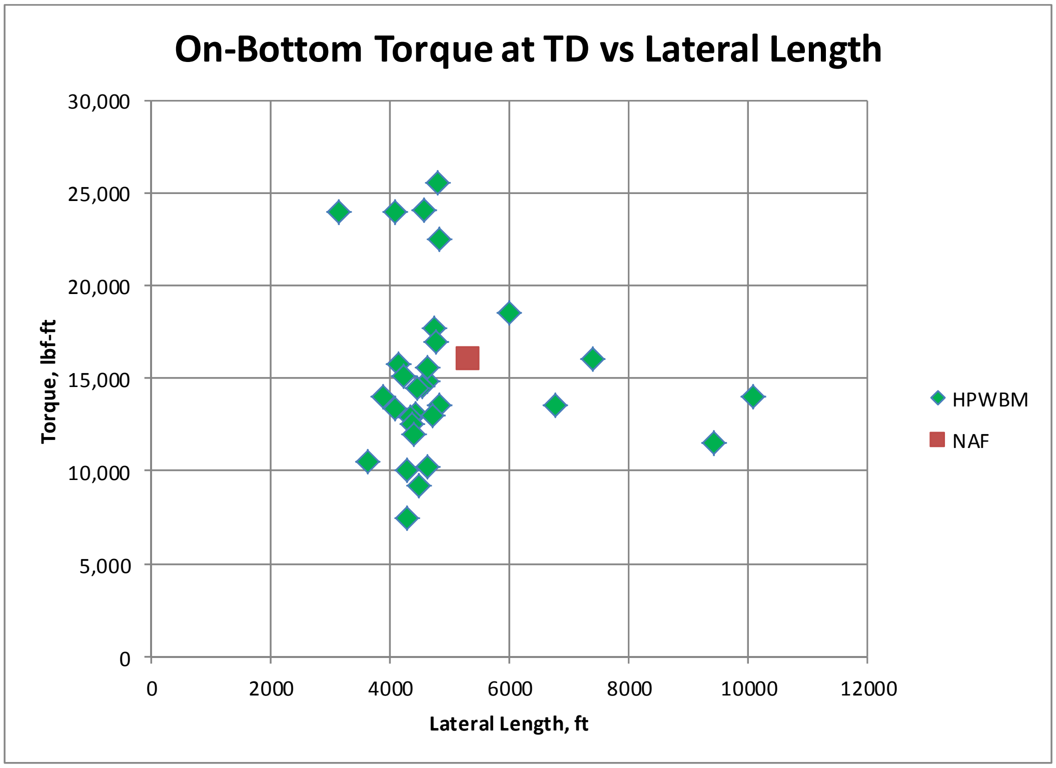

Fig. 6: On-Bottom Torque of HP-WBF & NAF versus Lateral Length

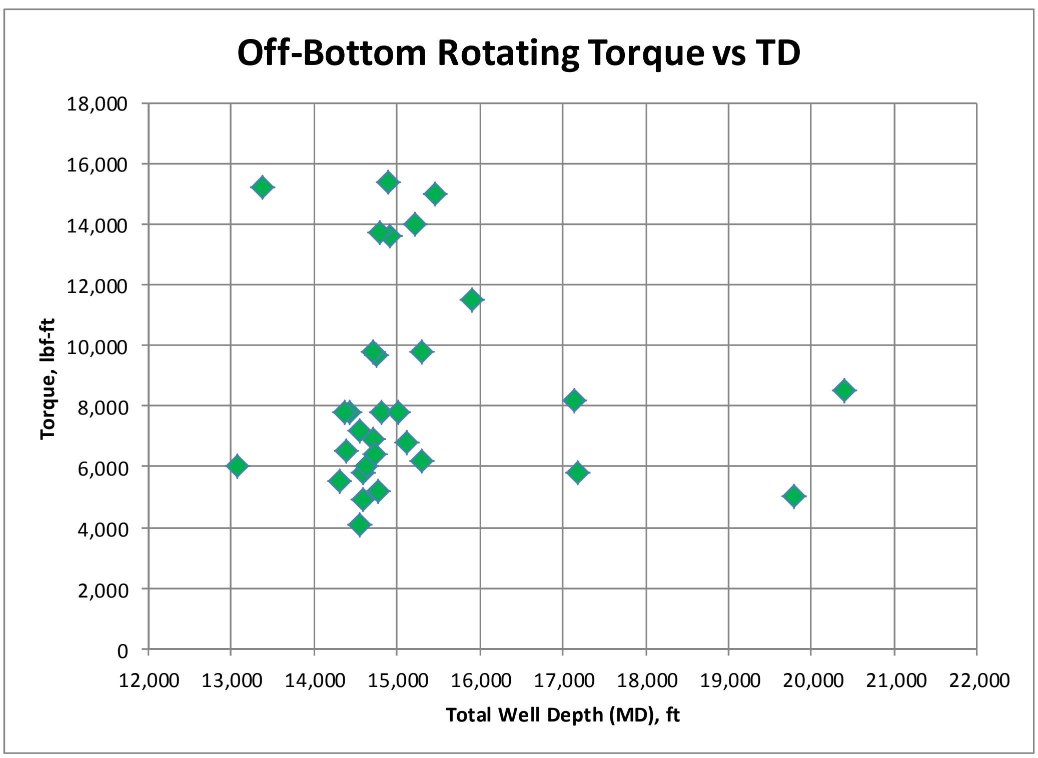

Fig. 7: Off-Bottom Torque of HP-WBF at TD

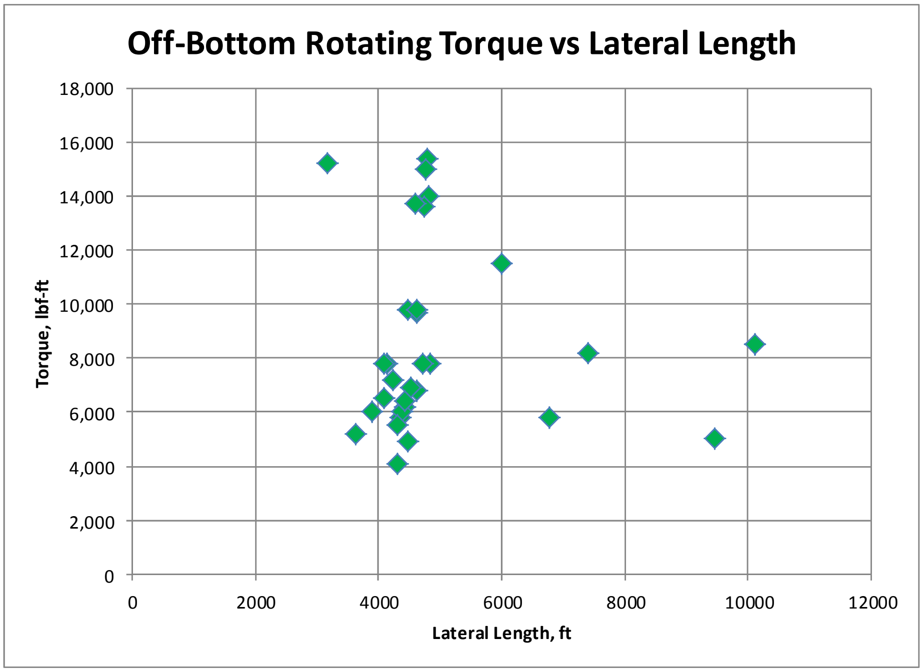

Fig. 8: Off-Bottom Rotating Torque vs Lateral Length

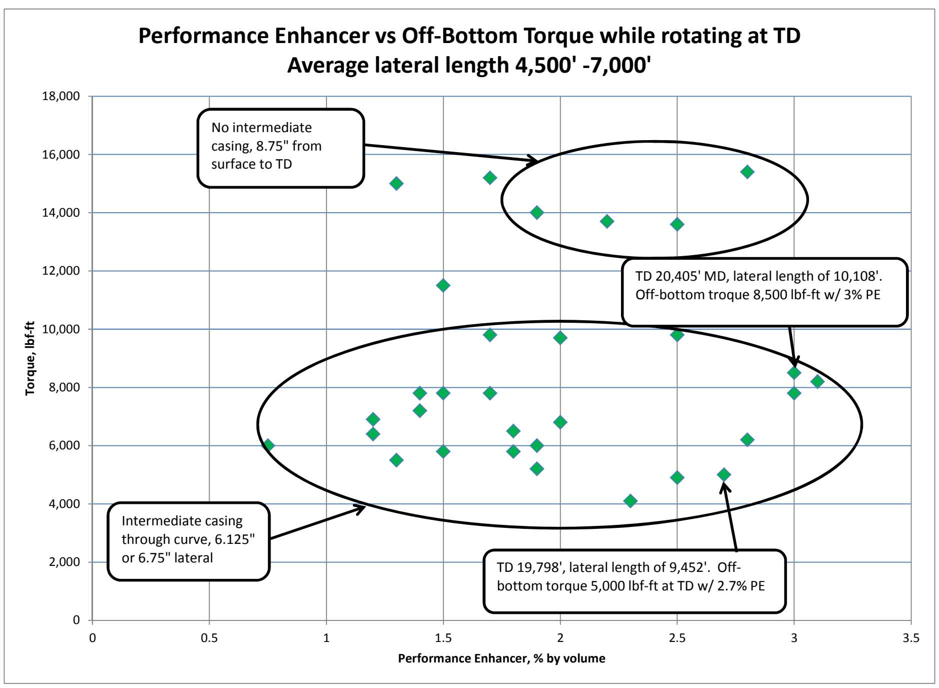

Fig. 9: Off-Bottom Torque and Performance Enhancer % by volume

LESSONS LEARNED AND BEST PRACTICES

Over the past two years a HP-WBF used to drill Cotton Valley horizontal wells was successfully designed, executed, and refined. During this process vital challenges were overcome and best practices were identified and captured. This has ultimately contributed to the goal of achieving the best fluid possible. In general, the philosophy is that continuous improvement must occur and that total optimization is never fully achieved. The data and thus results are assessed and analysed to make quantitative decisions to formulate future guidelines.

Below are more pertinent lessons learned and best practices.

1. When building a new HP-WBF introduce the performance enhancer after certain drilling criteria are experienced.
2. Empirical data indicates that for lateral lengths less than 7,000 ft (2,134 m), an application of 1.5-2.5% by volume of the performance enhancer is in the fluid at TD. For laterals greater than 7,000 ft (2,134 m) the expectant concentrations increase to 2.5-3.0% by volume. This will yield the best advantage in terms of ROP and torque management.
3. Dilution rates improve functionality and performance of the HP-WBF. Based on a solids removal efficiency of 70% and a target low gravity solids (LGS) content of 5% by volume, 6 bbl (0.95 m^3) of dilution per 25 ft (7.6 m) of hole drilled is ideal for wellbore sizes of 6.125" or 6.75" wellbores. For 8.75" wellbores dilution rates should be 6 bbl (0.95 m^3) per 15 ft (4.6 m) of hole drilled.
4. Synergistic effects occur between the polymeric viscosifier and performance enhancer which improve overall operational performance. Fluid properties affected are API fluid loss and rheology.
5. Performance enhancer additions are most effective by whole mud additions instead of in a sweep regime.
6. Aluminium tristearate can help mitigate aeration and is most effective at 0.5 ppb (1.9 kg/m^3) or greater.
7. Fluid properties and performance are optimal with a pH of 9.5 – 10.5 standard units.

CONCLUSIONS

Multiple lessons were extrapolated from the challenges drilling the Cotton Valley Group with the HP-WBF. These experiences will be added to previous understandings to further the knowledge on this product line of drilling fluids. The use of the clay-free polymeric viscosifying agent was ideal to provide a low solids fluid that minimized the degree of abrasivity as seen in the extended life of the tools used in this area. This fluid was easily diluted to control any additional low gravity solids. Coupled with the product line's performance enhancer, torque and friction factors became more manageable and therefore total depths were achieved on or before expected time.

Empirical data demonstrates the advantages and cost effectiveness of selecting a HP-WBF to drill horizontal CV wells. The HP-WBF demonstrated consistent ROP increases and better torque values which had a direct effect on decreasing days drilling. . The HP-WBF has been found highly successful for this challenging monumental sandstone where operators' focus was to drill longer production laterals for improved production rates and return on investment.

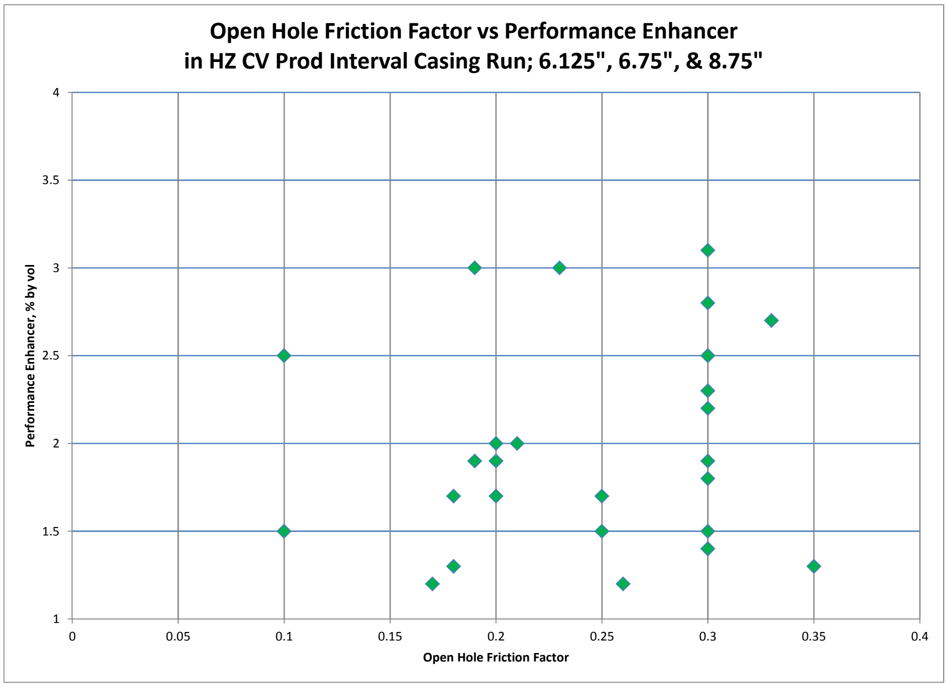

Fig. 10: Open Hole Friction Factor & Performance Enhancer

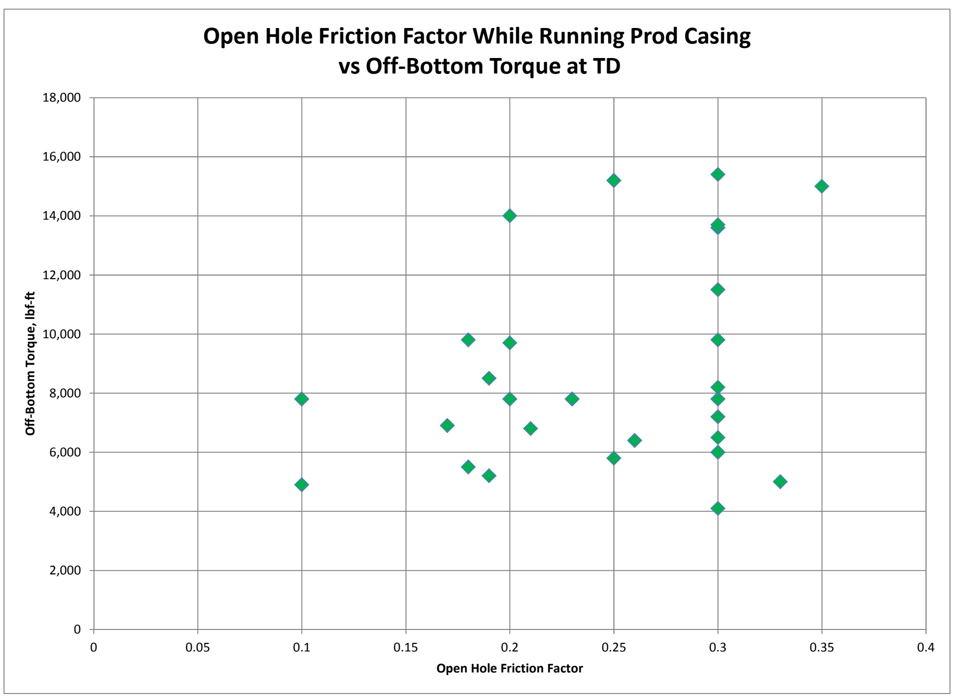

Fig. 11: Open Hole Friction Factor & Off-Bottom Torque

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APPENDIX

NEWPARK DRILLING FLUIDS Daily Torque and Operating Data

Well Name	
Location, S-T-R	
County/Parish	

Depth	Off Bottom Torque at 60 rpm while pumping, lbf-ft	Pick-Up, no rotary and no pumps, Klbs	Slack-Off , no rotary and no pumps, Klbs	Rotating string weight while pumping, Klbs	Performance Enhancer %, by volume	Diesel %, by volume	General Comments	COF, when available

Figure 12: Example of Torque Record Worksheet