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Optimizing Frac Plug Mill Outs in Horizontal Wells using Coiled Tubing

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Abstract

Due to the current market price of natural gas, operators have needed to reduce the overall costs associated with completing a well. Specifically, steps have been taken to significantly lower the costs associated with the mill out of composite frac plugs and frac sleeves using coiled tubing (CT). Shell's Eagle Ford group has successfully ventured away from traditional milling procedures that included numerous short trips, sometimes referred to as wiper trips. By incorporating a scientific approach and optimizing fluids system technology and bottomhole assembly (BHA) designs, these new methods have enabled us to eliminate short trips all together and produce cleaner wellbores. Ultimately, these new practices have achieved significant reduction in cost and time.

This paper will discuss the past coiled tubing performances and the need for changes. Analysis and theories used to implement and optimize Eagle Ford coil tubing operations will be reviewed. It will review and discuss the changes made such as fluid Quality assurance and controls (QA/QC) improvements, coiled tubing selection, and BHA design. These changes resulted in significant reduction in both cost and time per well and cycle time on a multi well location. These changes are now fully implemented and are the new standard for Shell's Eagle Ford coiled tubing operations.

Introduction

As a major operator in the Eagle Ford play, CT operations are an essential part to completing the wells. Utilization of CT allows the wells to be cleaned out and brought online without having to kill the wells thus potentially damaging the fracture treatments just performed on the wells. These operations had become expensive and required several days to complete the task because of the current activity levels and cost structures. The realization became apparent that changes needed to happen.

The typical well was drilled to an average 8000 feet true vertical depth, average horizontal lateral lengths of 5500 feet, and cased with 5.5 inch casing back to surface (Figure 1). Standard completions consisted of 15 stages using the plug and perforate method. Locations are multi-well pads that having 4 to 6 wells per pad with the wells spaced 15 feet apart. After fracture treating the wells, 2 inch CT was utilized to drill out the plugs and clean the laterals. Coiled tubing operations are one area that has seen much improvement since completing wells in the Eagle Ford. The largest factor contributing to the job for the operator is the time required to complete the job. Job cost and cycle time had been fairly constant but an upward trend was observed for both. This trend caused the operator to take a closer look at the CT operations and search for opportunities to improve its operational performance and efficiencies.

Challenges

New well designs and completion strategies are going to add new challenges. The proposed plans will add time and cost to an already challenging operation if changes are not implemented. The new wells are proposing for lateral lengths of 7500 feet and additional stages to the completion means more plugs to drill out. Future wells will be completed with 20 to 30 stages versus the current 15 stage completion. Wellbore cleaning, CT limitations, and BHA design all needed to be addressed in order to meet the new requirements for CT operations.

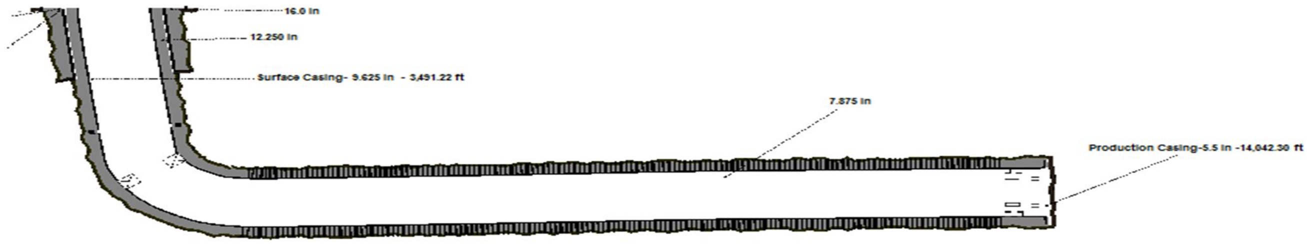

Figure 1 – Typical Eagle Ford Wellbore

Fluids

Hole cleaning is the major concern in horizontal well clean outs. The operator first considered how well the fluid systems were cleaning the wellbore. The current CT drill out operations encountered numerous amounts of sand which created extra friction and additional chemical usage in order to effectively carry sand and debris from the wellbore (Figure 2). The typical method for chemical mixing was a recipe of adding gallons of chemical per barrels of fluid pumped, sometimes referred as “batch treating”. This is the standard practice in the industry but there are questions on the effectiveness of this practice. These questions along with new technology caused the operator to look into quality assurance and control for our fluid systems.

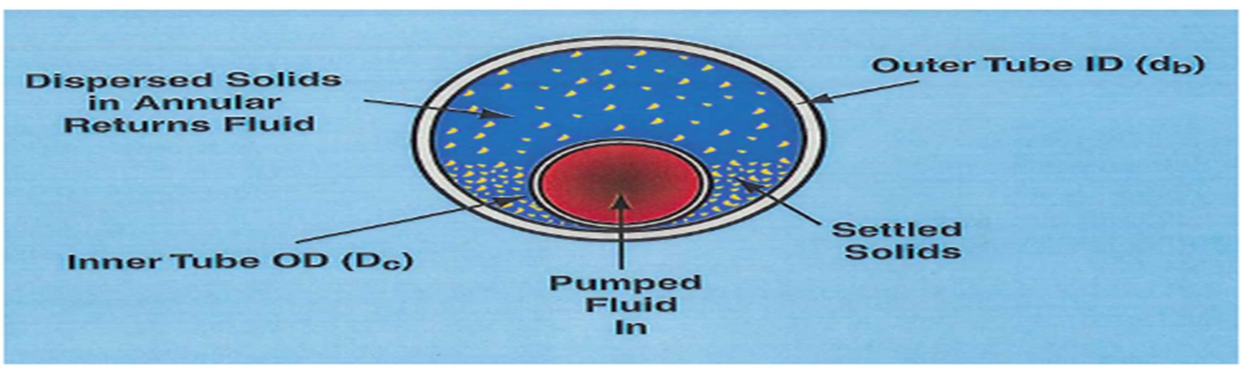

Figure 2 – Diagram of Solid Placement thru Horizontal Lateral

Collectively, the operator along with a chosen supplier looked into the fluid properties such as resistance, viscosity, annular velocity (AV), and the Rheology or Reynolds number along with the effects of each. Understanding how each of these parameters affects the fluid system and wellbore cleaning capabilities was essential to improving the optimization and efficiencies of chemical usage and fluids systems performance during CT clean out operations.

The term “viscosity” describes the measure of a fluid’s resistance to flow. The flow of liquid through a pipe is resisted by viscous shear stresses within the liquid and the turbulence that occurs along the internal walls of the pipe which is created by the roughness of the pipe material. This resistance is usually known as pipe friction and is measured in feet head of the fluid, thus the term “head loss” is also used to express the resistance to flow. Simply stated, the less viscous the fluid, the greater its ease of movement through the pipe. Understanding the effects of friction reducer dosage optimization and monitoring the fluids continuously helped quantify the correct amount of friction reducer needed to effectively overcome the internal friction of the fluids and reduce the circulating pressure or horse power required for pumping operations during the job. With the optimum chemical dosing, adjusting the flow rates and fluid regime was evaluated based on the 2 inch CT clean out and current wellbore configuration. Reviewing the parameters in the context of Reynolds number, it was determined that a critical value of 175 feet per minute AV was required to maintain a sufficiently turbulent flow through the lateral section of the wellbore. There are three types of flow regime - laminar, transitional and turbulent. Flow regimes are characterized by the relative amount of swirling or chaotic motion as the fluid moves along the pipe. Turbulent flow is an erratic, nonlinear flow of a fluid, caused by high velocity and low viscosity. Laminar flow is when fluids moves in parallel layers and the velocity of the fluid particles are similar regardless of position in the pipe. A laminar regime flows smoothly with instabilities being dampened by the viscosity. When the viscosity is naturally high, such as polymer solutions (gel) used in gel sweeps, flow is normally laminar and the Reynolds number is usually very small too.

- Flow regimes based on Reynolds Number: Laminar<2300> Transition <11,500> Turbulent

Although the 11,500 turbulent transition point is not typical in the common literature (canonical literature estimates the transition at Re=4000),the test results from our service provider, analysis of the data from our drill-outs, and the results of others in the literature (Nishi et.al, 2008, Journal of Fluid Mechanics, 614:425-446) show that “not all turbulence in created equally”. In order to achieve debris transport within the range of flow conditions observed in these drill-outs, an estimated RE# of 11,500 at the fluid-debris interface became the minimum level of turbulence required to initiate bedload debris transport. A cross-sectional AV gradient, and therefore cross-sectional RE# gradient, exists within an eccentric annulus (pipe-in-pipe). The highest AV’s and RE#’s occur in the ‘open’ side of the annulus, and the side of the annulus to which the pipe is biased has lower AV’s and Re#’s. Since achieving the turbulent transition in the eccentric side of the pipe (which tends to be the low side of the pipe in a horizontal well) is required to facilitate debris removal, a target RE# was identified, as measured by the fluid properties on the surface, that provides the down-hole conditions to remove the bedload and effectuate continuous hole cleaning during the drill out.

- Reynolds number = (Fluid velocity x Hydraulic diameter) / Kinematic viscosity

  (Hydraulic diameter is the relationship between the casing ID and the coil OD)

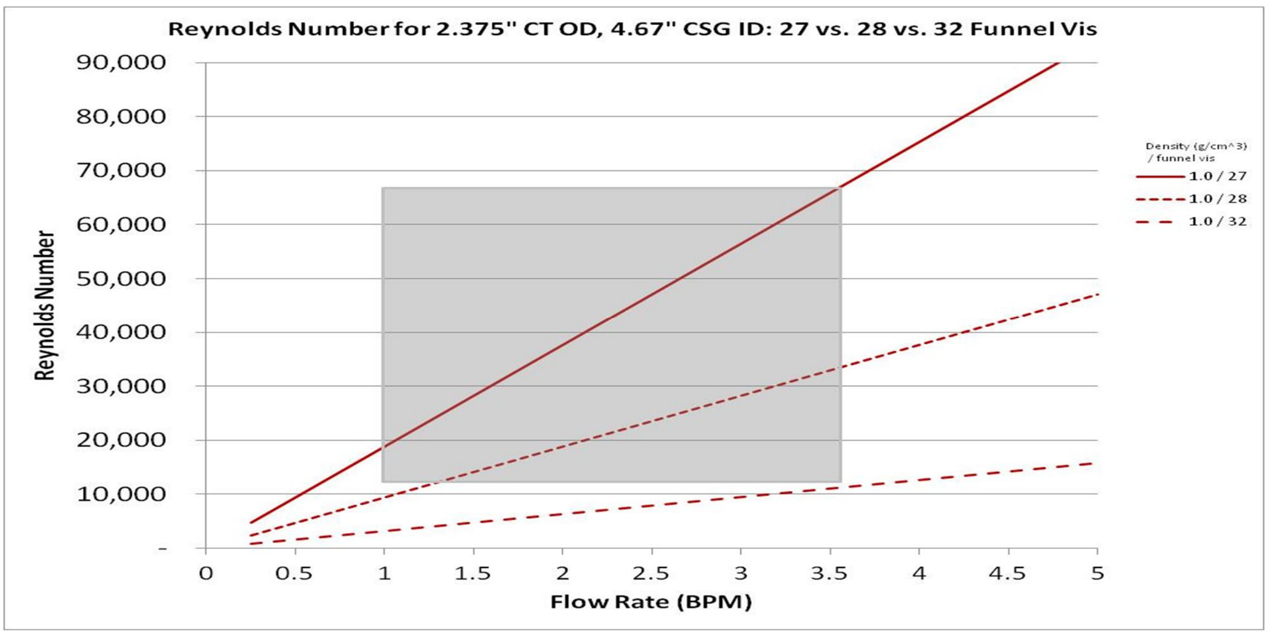

Figure 3 – Reynolds Number versus Funnel Viscosity

A subtle change in viscosity has a direct and significant effect on the Reynolds number (Figure 3). Using slick water with a fluid viscosity range of 28-29 funnel viscosity (3-5cp) and a pump rate of 2.5 BPM, the Reynolds number (as measured on surface with a simple funnel viscometer) is approximately 22,000. At 3.5 BPM, the Reynolds number is 32,000. The minimum recommended Reynolds number which ensures a sufficiently turbulent regime in the eccentric portions of the lateral section is achievable in both BPM examples above. The gel sweeps, which had a funnel viscosity range of 60-70 funnel viscosity (35-45cp), created lower Reynolds numbers and laminar flow. Knowing the effects of the viscosity of gel sweeps, the operator was able to reduce the sweep volumes from 10 barrels to 5 barrels after milling through each frac plug. While improving fluid efficiency by continuously monitoring the fluids and taking samples every half hour (minimum), the operator was able to reduce the amount of friction reducer used by 47% and gel usage by 42%, while removing greater amounts of debris from the well bore and without sacrificing pumping pressures or fluid balance. Figure 4 below graphically represents the overall reduction in chemical usage and job cost by implementing the Reynolds number approach and monitoring how chemicals were being mixed during jobs.

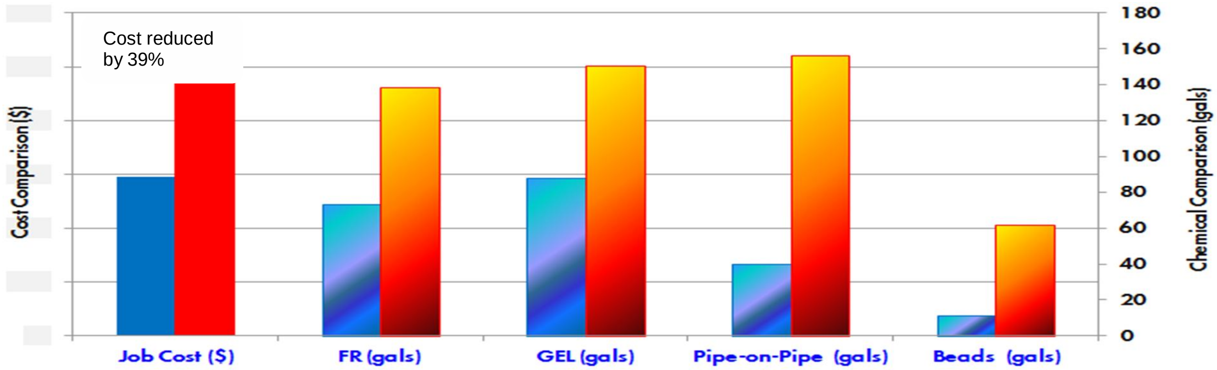

Figure 4 – Company Comparison on Cost and Chemical Reduction

The illustration (Figure 5) below shows how, over time, the operator was able to reduce the gel usage by 40%, all the while increasing the number of plugs per well. In all, less chemicals used during the job and better QA/QC contributed to a 58% reduction in chemical cost per well.

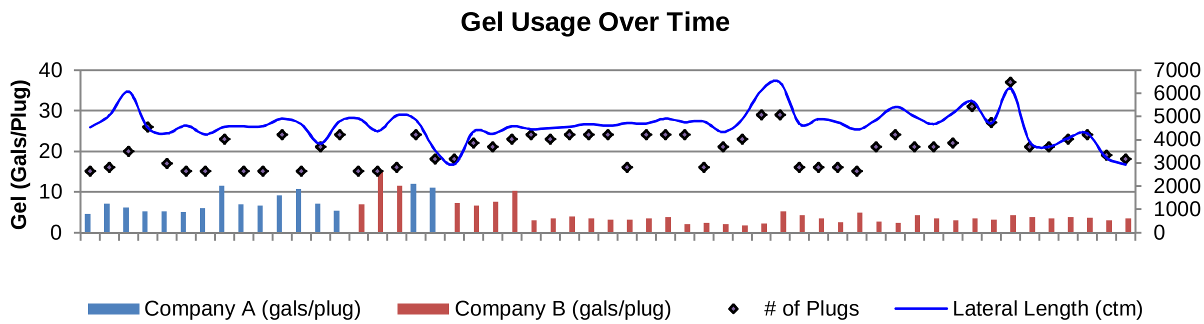

Figure 5 – Gel Reduction Comparison versus Number of Plugs

The chemical reduction and cost were achieved by continuously monitoring and optimizing chemical usage within the fluid system. This consistent on-the-fly QA was very cost effective and essential in improving drill-out efficiency and effectiveness. Utilizing a third party chemical company (Figure 6) that was equipped to mix and monitor the fluids throughout the job was a new concept for the operator. In this set up, the fluids and chemicals are pumped through the mixing plant and mixed on the fly while monitoring the chemical concentrations and fluid performance parameters. The mixing plant pumps and then feeds the fluid to the coiled tubing pumps.

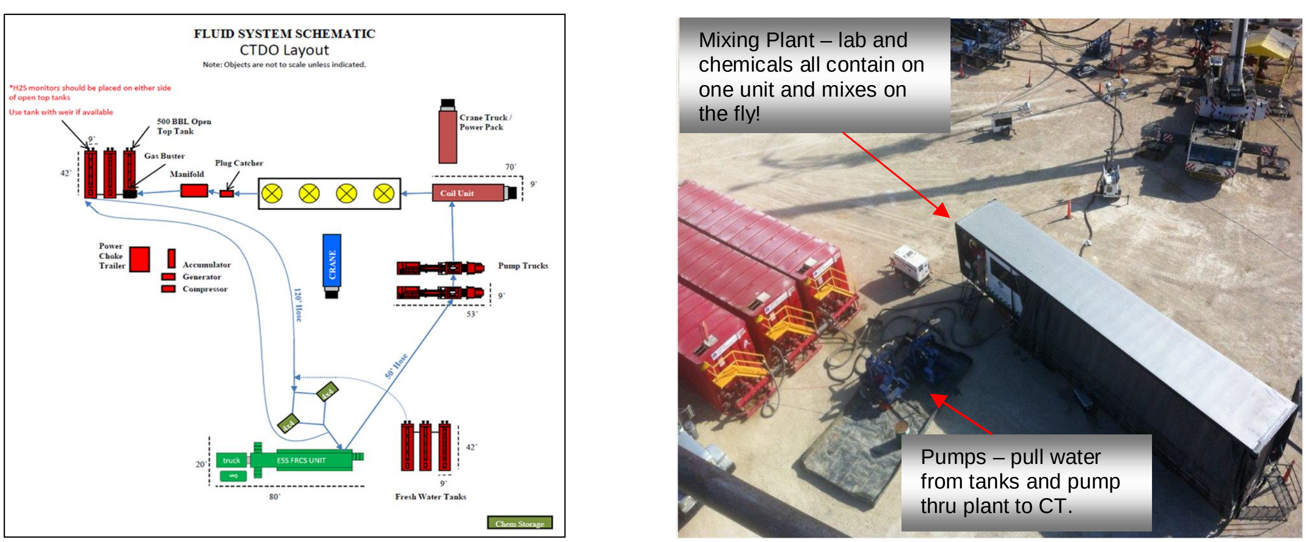

Figure 6 - General Layout for Coiled Tubing Operation

Continuing to evaluate the fluids along with the rates 2 inch CT operations showed that even with the correct Reynolds number, the AV was under the desired velocity required for turbulent flow. With the low AV and understanding the effects of the gel viscosity sweeps, hole cleaning was only adequate. Average rate through the BHA assembly on 2 inch CT was 3 BPM which would just meet the engineered required AV for efficient hole cleaning capabilities (Figure 7) on the current wellbore design. One option to increase the annular velocity was to trial and ultimately utilize 2-3/8 inch CT. The trial was to determine if better performance could be achieved to reduce cost and time. With the larger CT, additional annular velocity was created but only slightly better than that of the smaller 2 inch coiled tubing. Another factor for trialing the 2-3/8 inch CT was due to the limits with the 2 inch CT such as pump rate with current BHA design, pump pressures and reach in long laterals.

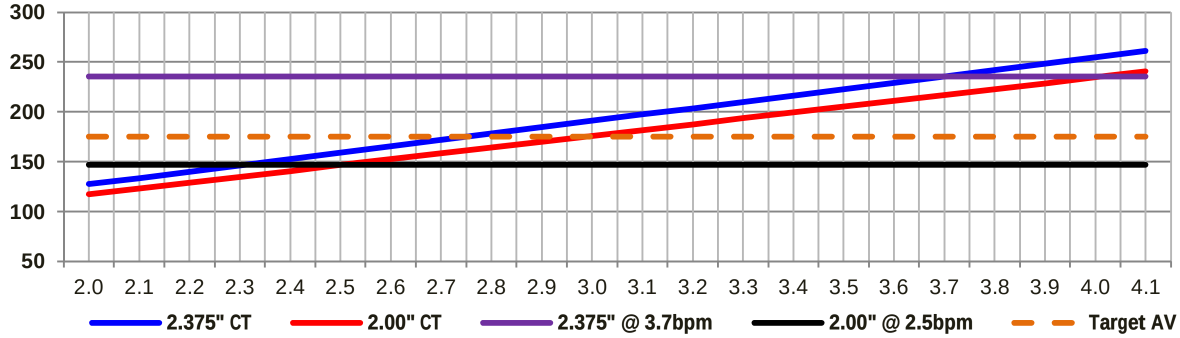

Figure 7 – Annular Velocity Chart versus CT Size and Pump Rate

The operator investigated ways to maximize rate and AV (Figure 9) utilizing the 2-3/8 inch CT unit. A redesign of the BHA was evaluated and our provider came up with a solution to achieve maximum AV at 4.0 BPM while maintaining optimum operating efficiencies for the motor. The BHA (Figure 8) was still optimized at 3.0 BPM flow rate until a ported sub and higher flow rate vibration tool were added. The ported sub was sized with the right orifices to provide the means to increase rate from ½ to ¾ BPM depending on surface pump pressures. The ported sub had a maximum capability to add an addition 1.0 BPM to the pump rate and increase the overall pump rate from 3.0 BPM up to 4.0 BPM maximum if needed. This change in rate increased the AV from 176 feet per minute to a maximum AV of 255 feet per minute. These rates created an AV that was highly effective for milling out the plugs and promote effective hole cleaning. Overall, these improvements allowed for a more aggressive approach to the operating procedure.

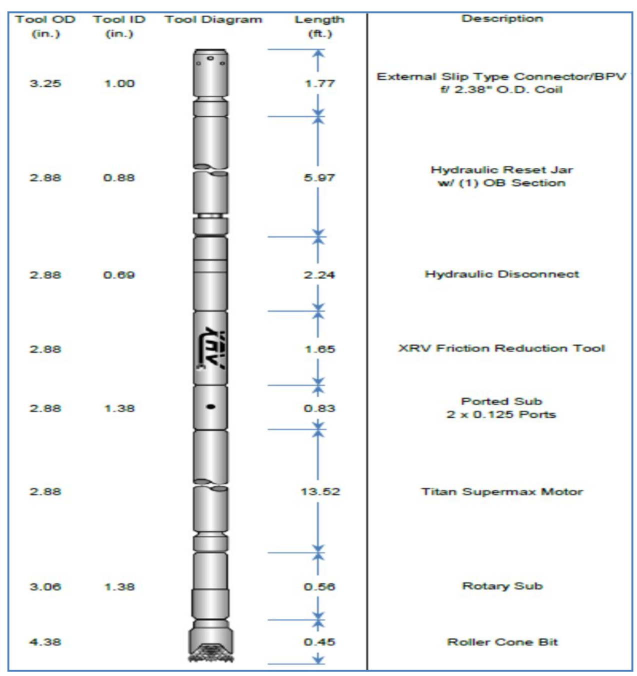

Figure 8 - Bottomhole Assembly

With a 2-3/8" CT unit and new BHA design for maximum AV and better QA/QC for the fluids, the operator explored how to utilize these changes to reduce time and cost without risking the improvements already put into practice. Working together with both the CT and BHA companies, a more aggressive approach was decided upon. The decision was made to increase the number of plugs per short trip and evaluate the results to establish the limits for number of plugs drilled out before doing a short trip (ST). With the smaller 2 inch CT and lower AV, five plugs was the maximum number of plugs that were drilled out before short tripping, which averaged a minimum of 4 trips per well based on a 15 stage completion. However, with the number of stages increasing, the number of STs would also increase. This meant more ST would be required which equates to more time and cost. An average short trip was 6 hours to complete. Again, the 2 inch CT was operating near the end of its capability and was not a good fit for the next generation of wells. The future plans for well design called for longer laterals up to 7500 feet and more stages, thus more plugs to drill out. Modeling showed that with the extended laterals in conjunction with additional friction caused by produced sand, 2 inch CT would "friction lock" before reaching plug back depth. Likewise, the modeling for the 2-3/8 inch CT showed no problems in being able to clean out the proposed longer laterals.

In a systematic approach, the operator began their first 2-3/8 inch CT operations on a well with 22 plugs. The operator drilled out 7 plugs before each ST and was done with 3 ST in 2.2 days without any issues. On the 2nd well, the operator continued to step out and increased the number to 10 plugs prior to the first ST and proceeded to drill out the remaining 13 plugs and clean out to plug back depth. This well was complete in 2 ST in 1.79 days, a decrease of half day from the first well. Feeling comfortable with the results and encountering no problems, the operator continued with the aggressive approach in order to reduce time and cost. Over the next several pads, CT drill out operations were performed in a single trip, no ST in the process of drilling out the plugs. This was a game changer for the operator. With an aggressive approach tied in with the changes described above, results were significantly improved with greatly reduced time and cost.

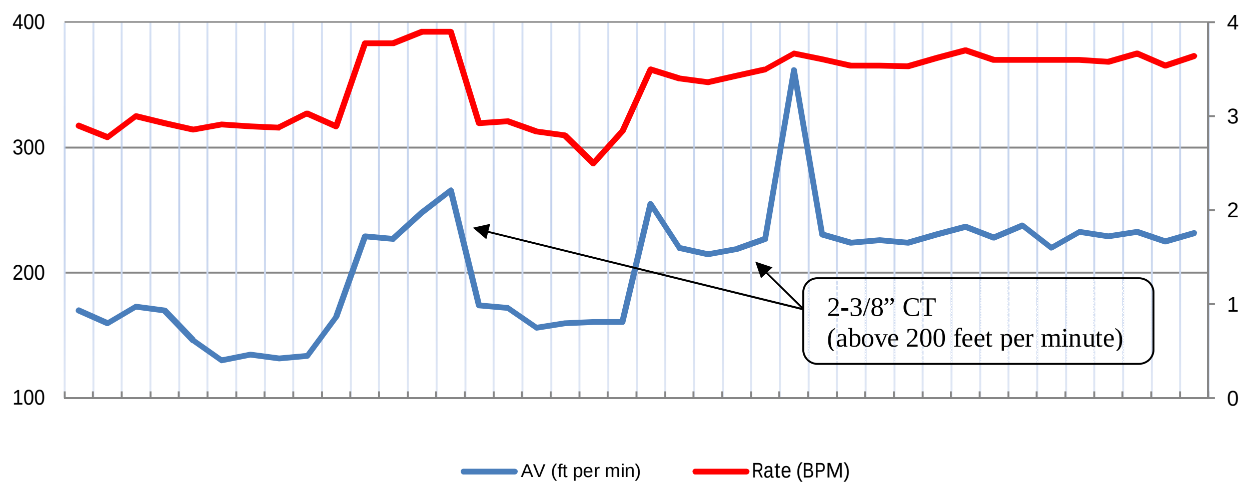

Figure 9 - Rate versus AV

Below is a chart summarizing the results using two different coiled tubing sizes used in similar well.

Fluid Rheology Metrics

	2" Coil	2-3/8" Coil	Change
Wells (Number of Jobs)	64	264	313%
Average Well Depth (MD)	16,708	15,366	-8%
Average Number of plugs	19	18	-5%
Average Slick water Funnel Viscosity	29.9	29.1	-3%
Average Slick water Viscosity (cP)	3.9	3.1	-21%
Average Annular Velocity	143	203	42%
Average Slick water Reynolds number	17,730	26,511	50%
Average number of Sweeps	40	24	-40%
Average Gel Sweep Pumped (Bbls per job)	273	155	-43%
Total Barrels Circulated	8,008	4,537	-43%
SWP Bbls/ Total Bbls	3.41%	3.42%	0.21%
Average Gel Sweep Viscosity	59	73.5	25%
Average Short Trips	4.24	1.07	-75%
Average Time (RIH to POOH)	72.24	25.1	-65%
Average CT Pump Rate (Bbls)	2.5	3.3	32%
Average Flowback Rate (Bbls)	2.43	3.28	35%
Fluid Balance	Balanced	Balanced	
Average Ft/Hr/Plug	14.2	70.4	396%
Average Hr/Plug	3.2	1.75	-45%

Key Points from Chart:

Wells were about the same depth and number of plugs to be drilled.

Average Annular velocity increased from 143 feet per min to 203 feet per minute (42% more)

Average Short Trip reduced from 4 to 1 (75% reduction).

Average Time reduced from 72.2 hours to 25.1 hours (65% reduction)

Average number of sweeps reduced by 40% (Cost reduction)

Slick water viscosity (cP) decreased by 21% (significant to the Reynolds Number)

Annular Velocity increased by 42% (significant to the Reynolds Number)

Reynolds number increased by 50% (biggest change of significance)

Fluid balance – maintained barrel in – barrel out ratio

Gel Sweep viscosity increased due to longer laterals, more plugs and maintaining lower bbl per sweep average.

Results

After evaluating and managing 50 plus drill outs, costs have declined while performance has improved. With the changes and improvements, the operator was able to reduce the coiled tubing cost (Figure 10) over 50% in a six month period. The ability to drill out all the plugs without performing a ST was a major breakthrough.

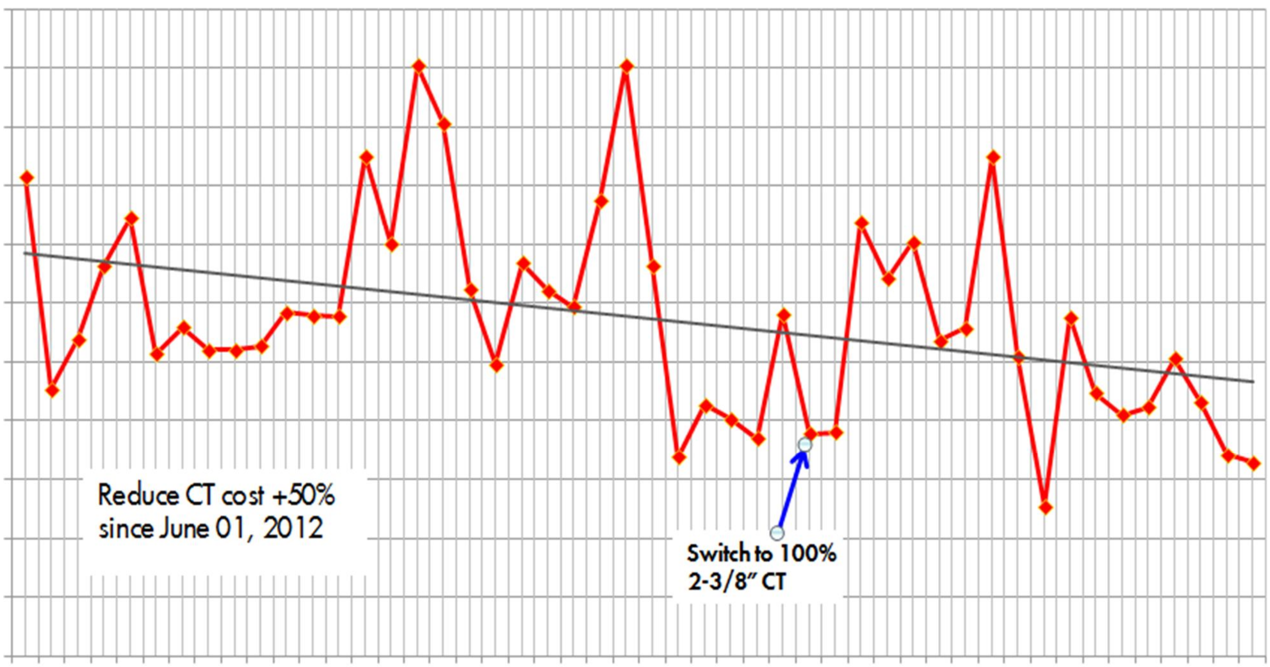

Figure 10 - Coiled Tubing Cost Performance

Another way to evaluate the results is to consider the operator's cost per lateral foot. In Figure 11, the average cost per lateral foot is shown for the operators 2 inch CT operations versus the performance when utilizing the 2-3/8 inch CT. The operator was able to improve and reduce its cost per lateral foot by 45%.

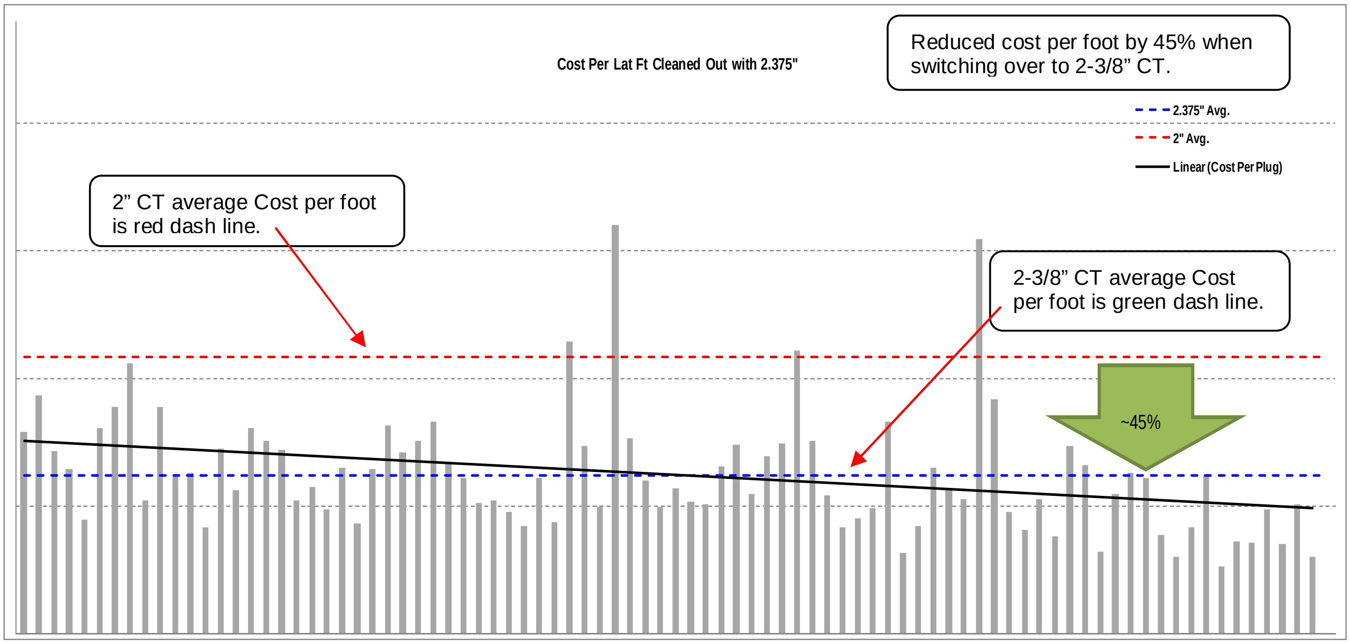

Figure 11 - Cost per Lateral Foot

Figure 12 shows how the operator was able to reduce the drill out times and total time in a well by 75%. This reduction equated to a day and a half less time spent on each well. Toward the end of the data gathering shown, the time on the wells was less than one day per well. By reducing the cycle time per well, it resulted in the operator reducing CT operations by a minimum of 6 days per pad. Reducing cycle time also allowed the operator to bring production on earlier. Items not included in these numbers is the extra cost, ST, and days if the smaller CT were to have been used to drill out the wells with 24 to 30 plugs. The savings would be even greater than what is shown in this study.

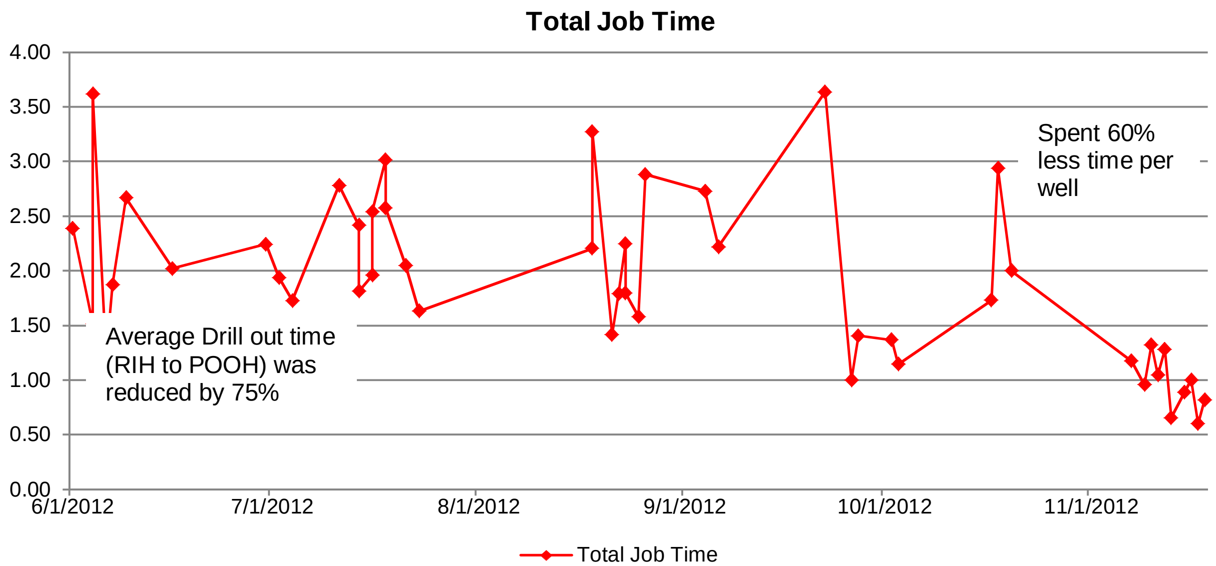

Figure 12 – Days per Well

With these efficiency improvements, the operator was able to achieve its goal of reducing cost and time while also improving the fluid system efficiency. As seen below (Figure 13), the larger CT performance was better in cost per well, plugs drilled out, and trips per well. The average number of plugs per trip for 2-3/8 inch CT was 18 plugs versus an average of 4 plugs per trip for 2 inch CT, a 400% increase. The maximum number of plugs drilled out with 2-3/8 inch CT was 31 plugs in one trip versus 5 plugs for the 2 inch CT. This performance reduced average trips per well from 4 to 1 per well using the 2-3/8 inch CT.

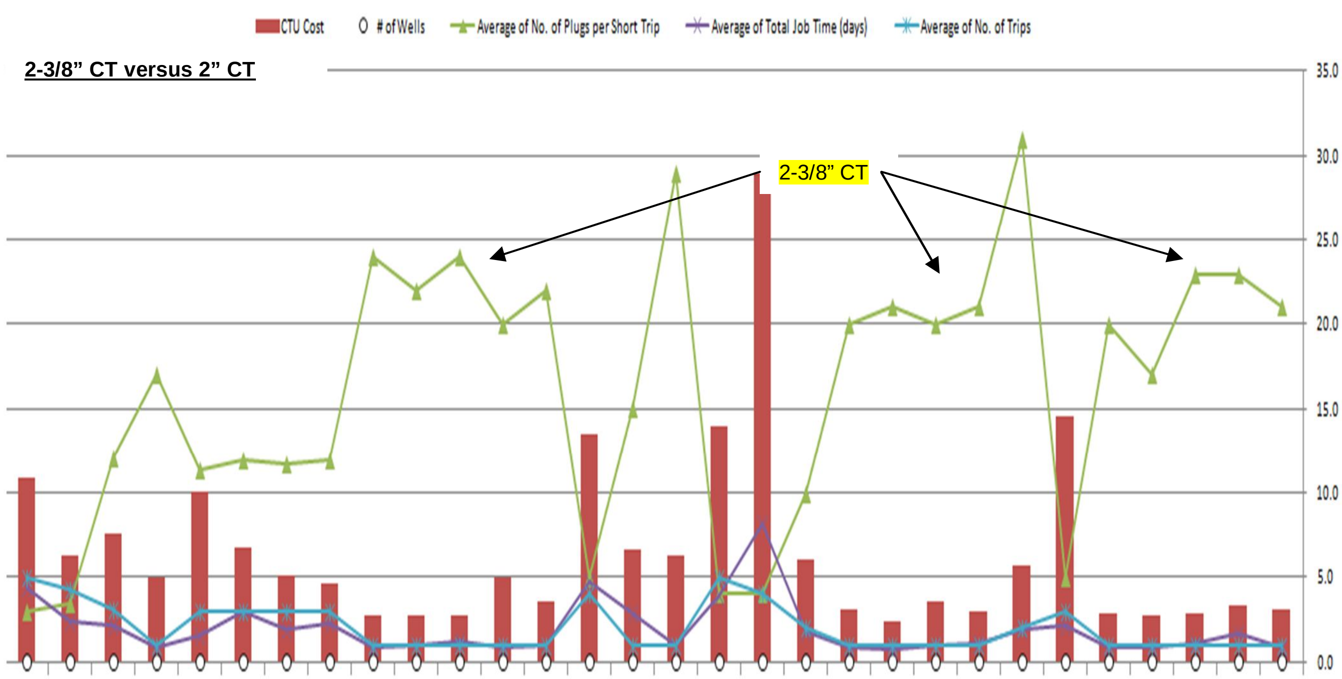

Figure 13 – Coiled Tubing Performance

Additional support that the changes made above provided clean wellbores was the results from a follow-up CT cleanout performed on a well prior to running a production log. Using the 2-3/8 inch CT and new BHA design along with lessons learned from this paper on the fluids, this was the debris captured from the clean out. The pictures below shows the amount of sand and debris recovered from the well eights months after the original mill out. Very little plug parts and sand was recovered.

Conclusion

The engineering approach of the operator and willingness to step outside normal practices proved to be very beneficial. The operator was able to achieve significant reduction in both cost and time through these efforts. Taking the time to evaluate each portion of the CT operations and individual components was essential optimizing our frac plug mill outs.

Through the engineering approach to deliver on both better hole cleaning and more efficient CT operations, the operator started by understanding and improving the QA/QC for the fluids used in the CT operations. While still running the 2 inch CT operations, changing the method of chemical mixing and understanding the specific properties such as flow regime, fluid viscosity and Reynolds numbers were essential in assuring good wellbore cleaning during CT drill outs. Mixing and continuous monitoring of the chemicals on the fly provided a means which to optimize chemical usage and improve the fluid efficiencies for removing debris from the well. Reviewing the wellbore configurations and fluids, the operator worked with the fluid company to develop the new parameters which provided the most optimum and efficient wellbore cleaning fluid system. This new process and improved efficiency led to a reduction in chemical cost alone by 68%.

While acknowledging this one component of the CT operations, the operator also evaluated the BHA design and CT size. Switching to the larger CT allowed the Operator to increase the pump rate and with the larger inside diameter of the CT, the surface circulating pressure decreased. The results of lower circulating pressures allowed the operator to change the BHA design which allowed for a rise in pump rates resulting in an increase in annular velocity. Making the necessary changes and improving the overall efficiency from each of these components enabled the operator to make the necessary changes and adjustment to dramatically improve this operation. These efforts, coupled with the knowledge of the resultant improved wellbore cleaning, the operator was able to make the progression of milling out frac plugs without performing a short trip in the process. This type of performance was a game changer for the operator and resulted in significant reduction in time and cost. The accomplishments and results that are presented were obtained within a six month period.

References

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