SPE-179087-MS

A Vibratory Tool Study on Extended Reach Horizontals During Coiled Tubing Drillout in the Eagle Ford Shale

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This paper was prepared for presentation at the SPE/ICoTA Coiled Tubing & Well Intervention Conference & Exhibition held in Houston, Texas, USA, 22–23 March 2016.

Abstract

As the Oil and Gas Industry continues to evolve, operators are pushing the limit to lengthen their reach in the reservoir to contact more payzone. Correspondingly, challenges for traditional downhole operations are steadily increasing. One of the more significant challenges is coiled tubing's ability to reach target depth. This has flooded the industry with a number of vibratory tools which would enable the traditional practices of coiled tubing to continue.

A study of vibratory tools was conducted on five wells in the Eagle Ford field. The purpose of the vibratory tool study was to gain a better understanding of top competing tools and how they compared. A total of five different wells were drilled out. Four of the five wells were drilled out using different vibratory tools while one of the wells was drilled out without any vibratory tool. While the wellbore geometries varied slightly, general characteristics remained consistent.

The four tools chosen for the trial were identified as top competing tools in the industry for the Eagle Ford area. Three of the tools used exerted an axial force on the coiled tubing while the fourth tool exerted a radial / lateral force. The trial well with no tool used friction reducer in place of the vibratory tool. Coiled tubing was only successful at reaching bottom on three out of the five trial wells.

While results are inconclusive as to what "the best" tool is; they certainly can provide contrast between each tool. Certain variables such as the wellbore geometry, inconsistencies in chemical usage and fluid condition differed from well to well and may have played a role in a tool's performance. Despite these differences, the tool that performed considerably well has a fluidic design and operates with no moving parts.

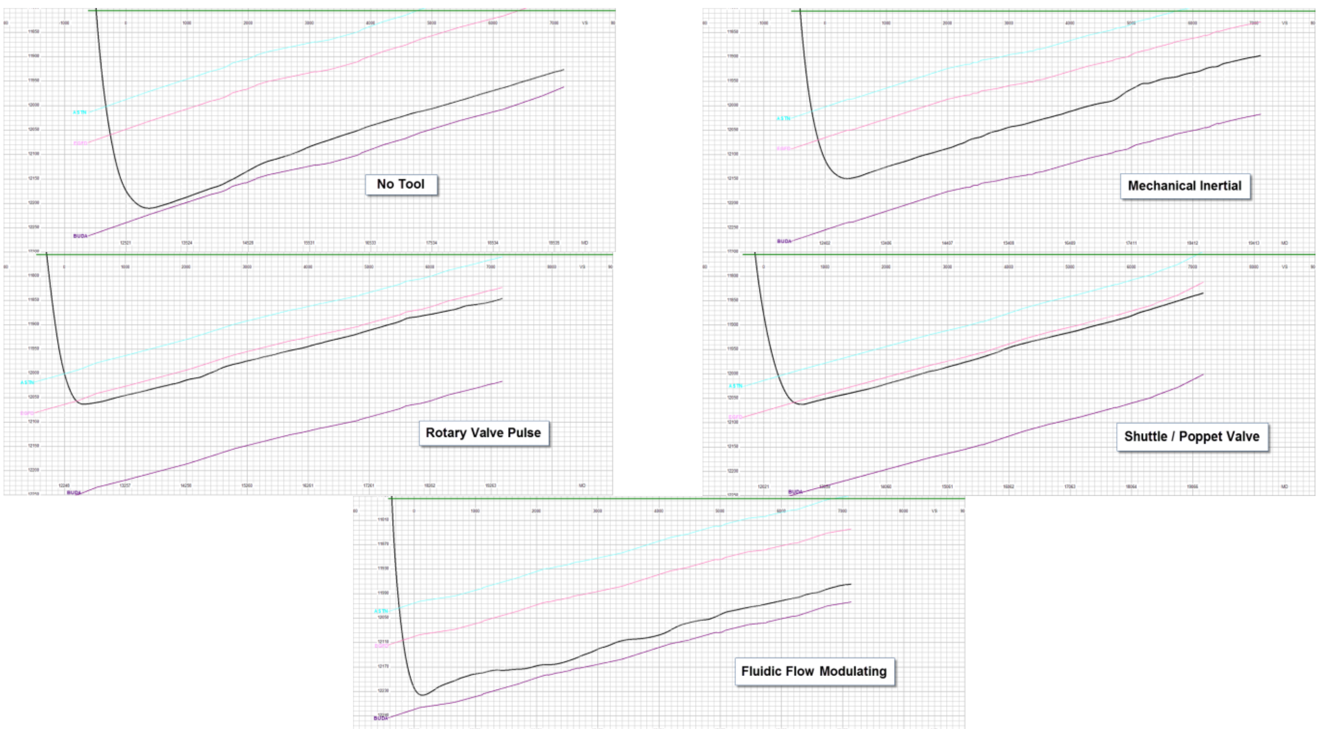
Introduction

For typical stimulation work in the Eagle Ford, composite frac plugs are used to isolate stages through the lateral. The number of plugs in a well directly correlates to the lateral length and the stage spacing chosen by the operator. After stimulation, the composite plugs must be drilled out prior to bringing the well onto production. Coiled tubing is the operator's preferred method for milling out frac plugs and cleaning the wellbore of sand and debris.

Vibratory tools are incorporated in the bottom hole assembly (BHA) to help reduce the friction caused by the coiled tubing contacting the casing wall. The primary function of these tools is to keep the coiled tubing in a state of dynamic friction. With the evolution of horizontal wells, vibratory tools have become a crucial component in downhole BHAs for coiled tubing operations. Over the past few years, many tools have flooded the market claiming to provide the best friction reducing capabilities. This study was completed to determine the most optimal tool for the operators current practices in the Eagle Ford.

Well Geometry

Horizontal wells are utilized in South Texas to contact more of the producing zone. Typical wells for the operator have a range in lateral lengths from ~3,000' to 8,000'+. True vertical depth (TVD), azimuthal direction and inclinations also vary depending on the area in which the well is drilled and the orientation of the wellbore. The coiled tubing extended reach tool study was done on five wells in Live Oak County. Wellbores were oriented on an azimuth of 358° with an inclination averaging 92.0°. Below are the geo-steering interpretations of each wellbore.



Vibratory Tools

There are two basic vibratory tool methodologies currently on the market, mechanical inertial tools and flow interrupting tools.

- Mechanical Inertial Tools

  These tools rely on using fluid flow to create linear or rotational movement of mass components within the tool to impart inertial vibration to the workstring. The lateral vibration is used to break the friction between the coiled tubing and the casing wall. These systems convert hydraulic power into mechanical vibratory energy.
- Flow Interrupting Tools

This type of tool utilizes a “valve” function in which the flow restriction through the tool varies with time. This periodic change in flow restriction causes oscillating backpressure across the tool as fluid is pumped through it. As a column of fluid travels through the workstring it encounters this changing flow restriction. When the flow is interrupted by the vibratory tool, pressure above the tool increases due to both the water hammer effect as the fluid column decelerates and the continued flow of fluid into the workstring by the positive displacement surface pumps. This increased pressure acts across the hydraulic area of the workstring causing the workstring to elongate producing downward movement of the workstring at the tool. When the flow restriction across the tool then decreases, fluid pressure above the tool is relieved and the workstring contracts to its original length. This process repeats itself as fluid flows through the tool causing vibration of the workstring. Additionally, if the vibratory tool is placed near the bit or mill, fluid pulses created by the vibratory tool will be exhausted through the bit instigating a change in pressure between the bit face and the formation or any object being milled. This changing hydraulic loading at the bit face causes an oscillating load between the bit and the target creating a “hammer drill” effect, which enhances the milling or cutting process. The operation of a flow interrupting vibratory tool is illustrated in Figure 1.

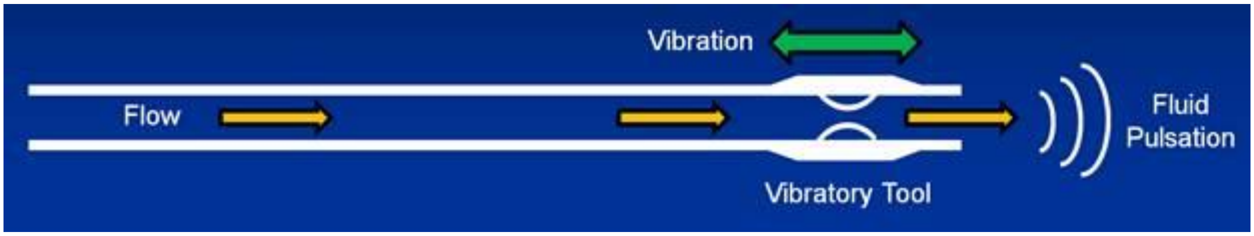


Figure 1. Operation of a flow interrupting vibratory downhole tool (Schultz 2013)

There are three classes of flow interrupting vibratory tools available on the market. These tools must be designed to withstand millions of cycles during a typical job.

- Classes of Flow Interrupting Vibratory Tools
    - Fluidic Flow Modulating Tools
    - Rotary Valve Tools
    - Shuttle/Poppet Valve Tools

Fluidic Flow Modulating Tool

This type of vibratory tool has been used extensively in coiled tubing and drilling operations and more recently in casing installation applications. This type of tool utilizes a specialized flow path to create a varying flow resistance which acts much like an opening and closing valve without having any moving parts or elastomeric components. The “valve” function is created using fluidic elements coupled together to create a self-induced, oscillating change in pressure above the tool.

- Characteristics of Fluidic Flow Modulating tool
    - No moving parts, highly reliable

- No elastomers, no issues with fluids, chemicals or gases.
- No temperature limitation
- Very short and rugged

Rotary Valve Pulse Tools

Rotary valve pulse tools have been around for more than 10 years. This type of tool utilizes a rotor/stator pair attached to a valve element which momentarily interrupts flow as it moves the valve element repeatedly through open and closed valve positions. It is essentially a mud motor which, instead of turning a bit box, turns an internal valve which causes oscillating backpressure across the tool.

- Characteristics of Rotary Valve Pulse Tools
  - Effective and reliable under non-extreme conditions
  - Long history of effective operation
  - Elastomeric stator, not suitable for exposure to high temperature, chemicals, gas etc.
  - Relatively long length

Shuttle/Poppet Valve Based Vibratory Tools

These tools are comprised of a combination of shuttle/poppet valve components which oscillate in response to flow through the tool. Internal valve components are arranged such that they shift between open and closed positions in response to flow through the tool. This process is repeated to create the desired pressure oscillation above the tool. There have been various tool designs of this type.

- Characteristics of Shuttle/Poppet Valve Tools
  - Generally simple and relatively inexpensive
  - Can be designed with minimal or no elastomeric components
  - Relatively short length
  - Less debris tolerant than other types of flow interrupting vibratory tools

Discussion of Trial

Depth limitations of coiled tubing during well cleanout have been an issue seen by the operator in the Eagle Ford on many extended reach wells. The five well trial was completed to determine the optimal tool for reducing friction and extending the reach of the coiled tubing units. As stated above, all the wells have similar well profiles, depths and inclinations.

Trial Parameters

- Production Casing Size
  - 5-1/2” 23# T95/P110 casing
- Coiled Tubing Unit
  - 2-3/8” Coiled Tubing Unit
- BHA
  - Assembly consisted of 2-7/8” OD tools and Downhole Motor
  - 4-1/2” roller cone bit

- *BHA was kept consistent between all wells; only changes being made to the vibratory tool.*

- Fluids
  - Attempted to keep fluids similar throughout the trial
    - *Varying chemical usage made analysis more difficult*
  - Pump rates kept consistent through entire trial
- Milling Parameters
  - Similar weight on bit was used during milling of the composite plugs

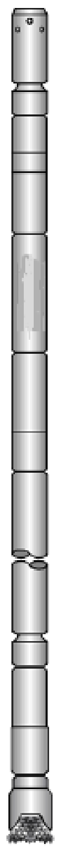
Tool OD (in.)	Tool ID (in.)	Tool Diagram	Length (ft.)	Description	Connection (Make-Up Torque)
3.25	1.00		1.77	External Slip Type Connector / Dual Flapper Check Valce f/ 2.38" O.D. Coil	2-3/8" PAC Pin Dn (2,300 Ft/Lbs)
2.88	0.69		2.24	Hydraulic Disconnect	2-3/8" PAC Box Up (2,300 Ft/Lbs) x 2-3/8" PAC Pin Dn (2,300 Ft/Lbs)
2.88			2.01	Vibratory Tool	2-3/8" PAC Box Up (2,300 Ft/Lbs) x 2-3/8" PAC Pin Dn (2,300 Ft/Lbs)
2.88			1.33	Plunger Type Valve	2-3/8" PAC Box Up (2,300 Ft/Lbs) x 2-3/8" PAC Pin Dn (2,300 Ft/Lbs)
2.88			13.73	Motor	2-3/8" PAC Box Up (2,300 Ft/Lbs) x 2-3/8" PAC Box Dn (2,300 Ft/Lbs)
3.13	1.00		0.56	Rotary Sub	2-3/8" PAC Pin Up (2,300 Ft/Lbs) x 2-3/8" REG Box Dn (2,586 Ft/Lbs)
4.50			0.50	Roller Cone Bit	2-3/8" REG Pin Up (2,586 Ft/Lbs)

Figure 2: Typical BHA setup for drillouts of composite plugs

Results of Trial

As stated above, the trial was completed on five wells on a pad. Of the five wells, one was drilled without utilizing a vibratory tool and the other four used varying tools that previously proved promising in the surrounding area. Friction models were completed on each well prior to drilling out the plugs. Friction matching using the information gathered from the onboard data acquisition system was used to determine the post-job friction coefficient that was achieved. The friction matching results from each well can be viewed in Table 1 below.

- **No Tool**

  The drillout utilizing no vibratory tool was unable to reach plug back total depth (PBTD). Total lateral length for this well was 7,223' with an average dip of 92.4° (up-dip well). Coiled tubing lockup was seen 1,683' short of PBTD. On this well, friction reducing chemicals were used to help reduce friction between the coiled tubing and casing wall. Pre-job modeling for this well showed a 0.25 friction coefficient and post-job friction matching showed the friction coefficient to be 0.35. This was a large increase in the friction coefficient which explains why the string was unable to reach PBTD. Once lock-up occurred, a clean out sweep was pumped and the BHA was pulled to surface. On surface, a Rotary Valve Pulse tool was added to the BHA. The new assembly was able to drill out the remaining composite plugs and reach PBTD.

- **Mechanical Inertial Tool**

  The drillout utilizing the Mechanical Inertial Tool was unable to reach PBTD. Total lateral length for this well was 7,030' with an average dip of 92.1° (up-dip well). Coiled tubing lockup was seen 1,473' short of PBTD. Friction models were done before and after the drillout of the plugs. Pre-job model showed for the well to have a 0.25 friction factor, using actual drillout data the post-job model showed the friction factor to be 0.35. This BHA preformed very similar to the BHA that did not utilize a vibratory tool. With the Mechanical Inertial tool only providing a lateral vibration, very little benefit was seen. Once lockup occurred, a clean out sweep was pumped and the BHA was pulled to surface. On surface, the Mechanical Inertial tool was laid down and a Rotary Valve Pulse tool was picked up in its place. The new assembly was able to drill out the remainder composite plugs and reach PBTD.

- **Rotary Valve Pulse Tool**

  The drillout utilizing the Rotary Valve Pulse Tool was successful in reaching PBTD. Total lateral length for this well was 6,862' with an average dip of 91.8° (up-dip well). Coiled tubing was able to reach PBTD with an average rate in hole of 11.5 ft/sec. Pre-job modeling for this well showed a 0.25 friction coefficient and post-job friction matching showed the friction coefficient to be 0.27. Post-job friction was still calculated to be higher than the pre-job, but the coiled tubing reached the necessary depth.

- **Shuttle / Poppet Valve Tool**

  The drillout utilizing the Shuttle / Poppet Valve Tool was successful in reaching PBTD. Total lateral length for this well was 6,548' with an average dip of 92.0° (up-dip well). Coiled tubing was able to reach PBTD with an average rate in hole of 15.3 ft/sec. Pre-job modeling for this well showed a 0.25 friction coefficient and post-job friction matching showed the friction coefficient to be 0.28. Post-job friction was still calculated to be higher than the pre-job, but the coiled tubing reached the necessary depth.

- **Fluidic Flow Modulating**

  The drillout utilizing the Fluidic Flow Modulating tool was successful in reaching PBTD. Total lateral length for this well was 7,222' with an average dip of 92.2 ° (up-dip well). Coiled tubing was able to reach PBTD with an average rate in hole of 16.1 ft/sec. Pre-job modeling for this well showed a 0.25 friction coefficient and post-job friction matching showed the friction coefficient to be the same 0.25. This was the only tool used where the post-job friction matching was equal to or less than the pre-job modeling.

Tool Type	Reached Bottom	Type of Force Applied	Lateral Length Reached	Rate in Hole [ft/s]	Pre-Job Friction Match	Post-Job Friction Match
No Tool	No	-	5540'/ 7223'	11.0	0.25	0.35
Mechanical Inertial	No	Radial / Lateral	5557'/ 7030'	10.3	0.25	0.35
Rotary Valve Pulse	Yes	Axial	6862'	11.5	0.25	0.27
Shuttle / Poppet Valve	Yes	Axial	6548'	15.3	0.25	0.28
Fluidic Flow Modulating	Yes	Axial	7222'	16.1	0.25	0.25

Table 1: Results from vibratory tool drillout trial

Conclusion

Based on the results of the trial, three of the total four tools used accomplished the task of reaching PBTD. It is hard to distinguish which tool preformed "the best" due to many potential variables accompanying this trial. The first and most apparent variable was that all the tools were run in separate wells. Well profiles were similar, but slight changes to the doglegs, backbuilds, inclinations and depths can have major effect on performance of coiled tubing and the ability to reach PBTD. Another variable seen through the trial was the inconsistences with the chemicals used in the fluids. See below for table indicating the volume of friction reducing chemicals used for each well.

Tool Type	Volume of Friction Reducing Chemical Used (gal)
No Tool	110
Mechanical Inertial	103
Rotary Valve Pulse	100
Shuttle / Poppet Valve	0
Fluidic Flow Modulating	125

Table 2: Volume of friction reducing chemical used per drillout during vibratory tool trial

Along with the usage of friction reducing chemicals, the quality of the fluid was reduced from well to well. A complete fluid swap was not done between wells (*see Table 3 for drill out order)*. The quality of the fluid for the first well was better than that of the final well.

Drill Out Order	Tool Used
1	No Tool
2	Rotary Valve Pulse
3	Mechanical Inertial
4	Shuttle / Poppet Valve
5	Fluidic Flow Modulating

Table 3: Drillout order during vibratory tool trial

Although the above variables were seen during the drillout test, the operator was able to make some conclusions based on the results. Integration of the BHA provider and vibratory tool manufacturer was an issue that had been seen in the past. Previous failures to the vibratory tool had caused fishing operations to take place. The BHA provider did not want to take responsibility for the failure because they did not supply the tool and the vibratory tool manufacturer did not want to take responsibility because they did not run the tool. Due to issues like this, the operator desired that the BHA provider manufactures, services, and supplies all equipment in the BHA.

Another factor taken into consideration was the vibratory tool's potential for failure. Fewer moving parts within the vibratory tool was thought of as a benefit to help prevent or mitigate any future problems relating to the vibratory tool.

With the above stipulations in mind, the operator felt most benefit was given to using the Fluidic Flow Modulating vibratory tool. This tool operates by using a specialized flow path to create varying flow resistance without the use of moving parts. Another advantage for the operator is that the coil tool company that has proven themselves as the preferred provider created this tool. With the Fluidic Flow Modulating vibratory tool being provided by the coil tool company, it eliminates any future third party liability problems. Along with these advantages, the operator felt like the Fluidic Flow Modulating vibratory tool operated extremely well through the drillout test.

Since the completion of the trial, all work has been given to the Fluidic Flow Modulating vibratory tool. The operator has drilled out 50+ wells without any issues.

Reference

Schultz, R. 2013. Good Vibrations. *Oil Field Technology February 2013:* 30-34