AADE-11-NTCE-47

Drilling Performance Improvements in Gas Shale Plays using a Novel Drilling Agitator Device

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Abstract

High friction of the drill string against the wellbore has become a concern in the process of drilling, irrespective of whether it is a vertical, directional or horizontal application. This source of additional torque and drag will lead to low rates of penetration, poor tool face control, short runs, severe drill string and bit wear, and at the same time, could cause problems while running casing, liners and completions. In directional and horizontal applications, this high friction could also lead to high well tortuosity, which will limit the amount of step out and can even impair productivity.

The implementation of a unique tool, referred to as a Drilling Agitator Tool (DAT), has demonstrated clear improvement in drilling performance by reducing stick slip and torque at the drill string. This has enabled reduction in drag and thus improved weight transfer to the bit when drilling through highly interbedded formations, directional applications or long horizontal sections. It has also shown greater accuracy in maintaining tool face control once the static friction was minimized. This DAT relies on three main mechanisms: a power section, a valve and bearing section and an excitation section. The tool operation vibrates the drill string with a low frequency and low amplitude axial vibration.

This paper illustrates case studies from the Haynesville, Fayetteville and Barnett Shale Plays, where the ADT has proven to help reduce torque and Stick-Slip when run on rotary in vertical applications, as well as Motor assemblies through directional and horizontal sections. These improvements in drilling performance have resulted in longer runs and faster rates of penetration compared to offset wells, thus reducing the number of bits and improving the economics in drilling these shale plays.

Introduction

The DAT has been widely used in different applications as a solution to the major problems associated with highly interbedded formations, low Rate of Penetration (ROP), buckling, sliding, erratic reactive torque, poor tool face control, oriented drilling with steerable motors, high tortuosity and extended reach drilling applications. The concept of the tool is based on reducing static friction and providing accurate weight transfer to the bit.

The hydraulic action of the tool creates pressure pulses which act on the pump area of a Shock Sub that generate an axial force at a determined frequency of the Agitator. The Axial vibration created by the shock sub gently oscillates the bottom hole assembly (BHA), reducing friction and improving weight transfer. In this way, weight is transferred to the bit, continuously and accurately without harsh impact forces. It has been demonstrated that the tools hydraulic action is benign, and does not have any detrimental damage to the bit, tubular or more sensitive equipment such as MWD/LWD. Consequently, standard downhole equipment can be used with the tool.

As the transfer of weight to the bit improves drilling performance in several ways, amongst some of the following benefits can be accomplished:

1. PDC bit life can be extended as the bit is prevented from constantly spudding into the formation. Several post run bit characteristics have shown that no damage to the bit occurred as a result of impact forces
2. Lower WOB will be required
3. Reduction in drill pipe compression as weight is transferred effectively and not dissipated at points where the BHA or drill string hangs up, minimizing the risk of differential sticking.
4. Tool face control is enhanced
5. Rates of Penetration are increased
6. Lower tortuosity and improved borehole quality

1. Drilling Agitator Tool Components and Operation

The DAT comprises three main components: power section, pulsing system and oscillating system. The power section is a 1:2 positive displacement mud motor. The pulsing system is a unique series of valves, driven by the power section and the oscillating system is a bellville spring actuated shock tool[1].

Since the power section is a PDM with a 1:2 lobe configuration, relatively high frequency pressure pulses are generated (generally 15-20 hz). As mud is pumped through the power section, the sealed cavities between the rotor and the stator progressively move the rotor and cause it to rotate. The pulsing system is placed at the lower section of the PDM's rotor.

The pulsing system comprises an Oscillating Valve Assembly (OVA) and a Stationary Valve Assembly (SVA) shown in Figure 1. The OVA is connected to the rotor and the stationary plate is fixed to the bottom sub. Due to the 1:2 lobe configurations, when the rotor rotates, the OVA moves back and forth in a near-linear sweeping motion called nutation. The OVA nutates, creating cyclical restrictions in the flow path as it passes over the stationary plate. The total flow area (TFA) changes from maximum to minimum generating the desired pressure pulses inside the string

The DAT gently oscillates the drill string in order to reduce friction in open as well as cased holes. The practical effect of reducing friction is improving weight transfer from surface to the bit. The axial oscillation in the drill string is generated through a series of pressure pulses coming from one part of the DAT. The pressure pulses act on the pump open area of a shock tool, generating the axial motion required to improve the transfer of weight to the bit and reduce downhole reactive torque. In most cases, the shock tool and pressure pulsing device comprise the DAT. The shock tool is recommended on jointed drill pipe (drill pipe with rotary shoulder connections). In coiled tubing applications, the wall thickness and flexibility of the coiled tubing allows the internal pressure pulses generated by the tool to pulse the string and reduce the wellbore friction.

A shock tool is required to create the optimum axial oscillation of the string to reduce friction in the hole. The shock tool has a mandrel, which is spring loaded in the axial direction. The mandrel is sealed between the internal drill pipe pressure and annulus pressure, creating a pump open area. When internal pressure is applied to the pump open area, the mandrel extends. Once the pressure is removed, the mandrel goes back to its original position. The shock tool is generally placed immediately above the DAT and will typically move axially between 1/8” to 3/8” during operation[2].

2. Compatibility of the DAT with other Drill String Components

There are many MWD tools used in the industry and they are rated for different levels of vibration. The most common means of determining downhole vibration levels is through the recording of “shocks”. A shock is usually recorded when an acceleration event of 25 g or greater occurs (Rewcastle -1992, Ashley-2001)[3]. MWD tools are built to withstand a laboratory verified number of shocks. The shock rate is also important. Shock rates of less than 10 per second are generally considered benign and above 10 per second are medium risk and finally, shock rates above 60 per second are considered a high risk for having a failure.

Even though the use of the DAT has shown some evident performance improvements when observing drilling parameters with and without the DAT in the drill string; quantifying actual downhole interaction between the DAT and other drill string components has been slightly more difficult. Some field tests have provided excellent insight into how the DAT interacts with the drill string and how it affects drilling performance.

The primary goal of these field tests was to quantitatively evaluate mechanical forces transmitted from the DAT to a Downhole Drilling Recording Tool (DDRT). The magnitude of these forces was compared to the specifications of other MWD providers to determine compatibility between the DAT and MWD equipment. The DAT used on these field tests was set up to provide a very high pressure drop (700 psi at 485 gpm and 10 lb/gal mud). This was done to allow measurement of downhole accelerations caused by the DAT in its most aggressive configuration

These field tests were run on identical drill strings apart from the addition of the DAT, the depths were almost identical, and the formations were similar. Additionally, the drilling parameters were purposely kept as close to identical as possible. Therefore, any changes in performance or downhole dynamic activity could be attributed to the addition of the DAT.

The downhole dynamic events were analyzed showing that slide drilling with a DAT did reveal slightly higher axial and lateral accelerations when compared to a non-DAT run. Maximum axial acceleration during the DAT run was 4.5g while the non-DAT run saw close to 3g while sliding[3]. Both of these axial acceleration levels were peak values and the averages for both runs were quite a bit lower, with both the DAT and non-DAT averaging about 2g axial.

In all the field tests the results were consistent, that even though acceleration levels were higher with the DAT in the drill string, the increases were low enough to retain full compatibility with the other components in the drill string. There were episodes of elevated vibration levels, both with and without DAT in the drill string. From these field tests it was demonstrated that adding an appropriately configured axial oscillation system to a drill string can improve drilling efficiency without compromising other aspects of the drilling assembly.

3. Implementation of DAT in Shale Plays

A diverse variety of challenges exist in the drilling operations in the shale plays within the United States. These include; highly interbedded hard and abrasive formations, high levels of vibration, high tortuosity and high drag and friction through directional and lateral sections. The implementation of the DAT has alleviated considerably some of the difficulties associated with this complex type of drilling.

3.1 Haynesville Shale

Bottom hole assemblies in the Haynesville shale experience a wide range of vibration during drilling operations through the vertical sections. These excessive vibrations can lead to failures to the different BHA components, low rates of penetration inducing to increase drilling costs due to loss of rig time, extra trips due to short bit life, equipment replacement, etc.

3.1.1 Vertical Applications

Drilling Performance through vertical sections in North Louisiana have been a challenge due to interbedded soft and hard and abrasive formations, at the same time variations in bit type, BHA configuration, drilling parameters make evaluating results from different wells very difficult. By ensuring most of these conditions are similar, the differences in downhole activity can be attributed to the axial and torsional oscillation system that affect the bottom hole assembly (BHA) and drill string as a whole, reducing the transfer of weight to the bit leading to a poor performance and lower rates of penetration.

The implementation of 8" DAT in the vertical sections of the Haynesville shale play when drilling a 9 7/8" hole size has demonstrated great improvements. In one of these applications in De Soto Parish, an 8" DAT was run on a rotary assembly, 98 ft behind the bit. This assembly went in at 8105 ft and drilled down to 9190 ft, for a total interval of 1085 ft in 52 hours at an average ROP of 20.9 ft/hr. It was reported that the tool reduced torque and Stick-Slip compared to offsets and almost doubled reported footage drilled per day. This assembly drilled 28 % faster, 43 % more footage and the bit came out in better condition (IADC Dull grade: 1-2-WT-S-X-I-BT-PR) compared to offset wells. Figure 2 displays a performance comparison with and without a DAT within a 5 miles radius.

3.1.2 Curve and Lateral section

In most of the shale plays, combining two intervals into one single bit run is one of the challenges drilling the curve/horizontal section, reducing the number of bits down to one to improve performance and drilling costs. Tool Face control, bit Steerability and durability are critical to be able to drill the entire section in a single run. Until recently, many intervals had been drilled with two bits.

In the Haynesville shale play the curve is commonly built below the Cotton Valley formation where the lateral section extends the borehole another 4,000 to 5,000 ft through the Haynesville shale. In these directional and long horizontal sections, the implementation of the DAT has provided excellent benefits by reduction in drag and frictional forces and thus improved weight transfer to the bit. It has also helped maintain tool face control once the static friction was reduced.

Figure 3 shows a performance comparison through a horizontal application where a 7:8 Motor, 3.8 stage with a bend housing of 1.75 deg was run with a 6 ¾" 5 bladed FC bit with16mm cutters. It drilled an interval of 1,502 ft at an average ROP of 15.4 ft/hr. However, due to the high friction, the ROP decreased to 12 ft/hr, forcing the BHA to be pulled out of hole. A DAT was added to the BHA and run back in the hole with the same bit and a motor with the same specifications. With this new assembly, friction was considerably reduced, being able to drill 2,098 ft at an average ROP of 18.6 ft/hr, providing improvements of 28% in footage and 40% in ROP. This assembly reached TD and the bit was graded as 1-1-WT-A-X-I-NO-TD.

Another extensive study (represented and summarized in Figure 4) included 185 wells in the Haynesville where 652 slim hole directional intervals were analyzed for performance. The first phase of this study analyzed a total of 110 runs using a DAT for friction reduction in the well bore. The second part used the data to help rationalize the question of running the DAT as a "planned Preventive Tool". The interval cost analysis comparisons of non-DAT versus DAT usage showed average savings of US$65,000 in drilling costs alone. From this data it was shown that from running a DAT, ROP can be improved by an average of 35% in the lateral and 30% in the curve section. This analysis was supported by several individual area well studies, broken down into three areas of similar drilling; depicting the normalized drilling time savings using the DAT versus a non-DAT. Area 1 included De Soto, Sabine and Red River parishes in North Louisiana, Area 2: Harrison and Panola counties in North East Texas and Area 3: Nacogdoches and Shelby counties in North East Texas[4].

3.2 Eagle Ford Applications

Offset data showed that wells drilled in this area were prone to sliding difficulties in the 6" range section of the wellbore. Additionally, frequent motor stalling and weight staking problems resulted in very low ROPs. As drilling proceeded to extended lateral depths (through the Lower Eagle Ford), the ROP decreased considerably due to high drag and torque, resulting in very short runs. The DAT has displayed excellent results, remediating some of these issues by helping to increase the sliding ROP. In one of the applications (in LaSalle County, Texas), a 6 ½" DAT was picked up after encountering lower than expected ROP and was run on a 6 ¾" mud motor. Placement was initially 1,998 ft above the bit through the curve and 4,277 ft through the lateral section. Over the two runs, the sliding ROP averaged 8.0 ft/hr which was three times faster compared to non-DAT, runs and 49.4 ft/hr rotating, about 20 % faster versus non-DAT runs. (Figure 5 shows a comparison for ROP and CPF)

3.3 Barnett Shale Applications

The DAT has also shown to improve drilling performance through the lateral section of the Barnett shale applications by reducing friction and minimizing sliding compared to other downhole vibrating tools (DVT). Performance comparison records depict the DAT providing higher reliability, drilling seven times more footage, minimizing the number of trips, and reducing the cost per foot (See Figure 6 that shows performance comparison between the DAT and DVT). Figure 7 displays another performance comparison in a lateral application in Johnson County, Texas, where the DAT helped to increase footage by 31.6 % and ROP by 30 % over offset wells within the same field.

In another application the DAT was used to complete the lateral section when a previous BHA run before the DAT failed to drill due to little or no weight transfer to the bit, resulting in a very low ROP that forced the pull the BHA out of the hole. The DAT was added to this BHA and run back in the hole. The ROP improved considerably from 15 ft/hr to a much more desirable 26.6 ft/hr, having a more efficient drilling that resulted in a 77% ROP improvement, a much better tool face control and directional control being able to effectively drill horizontally to TD. (See Figure 8)

3.3.1 Case study for Barnett Shale

A case study (summarized in Figure 9) was performed for the Barnett Shale area, specifically in Tarrant County after a major operator wanted to reduce the amount of hours needed to drill a well. As a result, 5 wells were drilled from the same pad, 2 wells with a DAT on their BHAs drilling through the curve and 3 wells without DAT. Three other wells (on the same pad) were drilled in the same area as the 5 wells previously drilled. The DAT was used "top to bottom" on these 3 wells (except in the surface section). The number of hours to complete each well was evaluated along with cost savings demonstrating that every time the DAT was run, the drilling time was significantly reduced, ROP increased and cost savings were enormous. In the wells where the DAT was run in the curve section, the ROP was improved by 19 % and the cost per foot reduced by 17 %, compared to the "non-DAT" wells. This equaled a total of US$22,500 cost savings for each well. When the "non DAT" wells were compared to the "top to bottom" Agitator runs, the ROP was increased by 65% over the "DAT-less wells" while a 58% cost savings were recognized, relating to a total of US$71,350 cost savings for each well and a total of US$214,000 for all 3 wells.

Conclusions

- The concept of the DAT is based on reducing static friction and providing accurate weight transfer to the bit, providing a very innovative and reliable solution to the problems associated with highly interbedded formations, low rates of penetration, buckling, sliding, erratic reactive torque, poor tool face control, high tortuosity, etc. that are common in the shale plays.
- The DAT relies on three main mechanisms: A power section, a valve and bearing section and an excitation section. The power section drives the valve section producing pressure pulses which in turn activate the excitation section, converting the pressure pulses into axial movement. It is the axial motion what breaks the static friction.
- Different field tests have provided very reliable information on how the DAT interacts with other components of the drill string and how it affects positively drilling performance.
- The DAT has proven to reduce torque and Stick-Slip when run both on rotary in vertical applications, as well as motor assemblies through the curve and lateral sections of the shale plays. These improvements in drilling performance have resulted in longer runs with an average of 30% more footage drilled, and ROP's increased by 35% (On average) compared to offset wells. They have reduced the number of bit runs and improved the economics in drilling through the shale plays by approximately 15%.

Nomenclature

BHA = *Bottom hole assembly*
BT = *Broken Teeth*
DAT = *Drilling Agitator Tool*
LWD = *Logging While Drilling*
MWD = *Measurement While Drilling*
OVA = *Oscillating Valve Assembly*
PDM = *Positive Displacement Motor*
ROP = *Rate of Penetration (ft/hr)*
SVA = *Stationary Valve Assembly*
TFA = *Total Flow Area*
TD = *Total Depth (ft)*
WT = *Worn Teeth*

References

1. National Oilwell Varco, Drilling Agitator Tool Handbook, September 2010.
2. National Oilwell Varco, Drilling Agitator Tool Operating guidelines, September 2010
3. McCarthy, J.P., Stanes, B.H., Clark K.W., Kollker C.R.: A Sten Change in Drilling Efficiency: Quantifying the effects of Adding an Axial Oscillation Tool within Challenging Wellbore Environments" SPE/IADC 119958 presented at the 2009 SPE/IADC Drilling Conference and Exhibition. Amsterdam, 17-19 March.
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6. Yavery, M. et al: "Solutions to the Down Hole Vibrations During Drilling" IADC/SPE 136956 presented at the 34th Annual SPE International Conference and Exhibition in Tinapa-Calabar, Nigeria, July 31 – August 7, 2010.

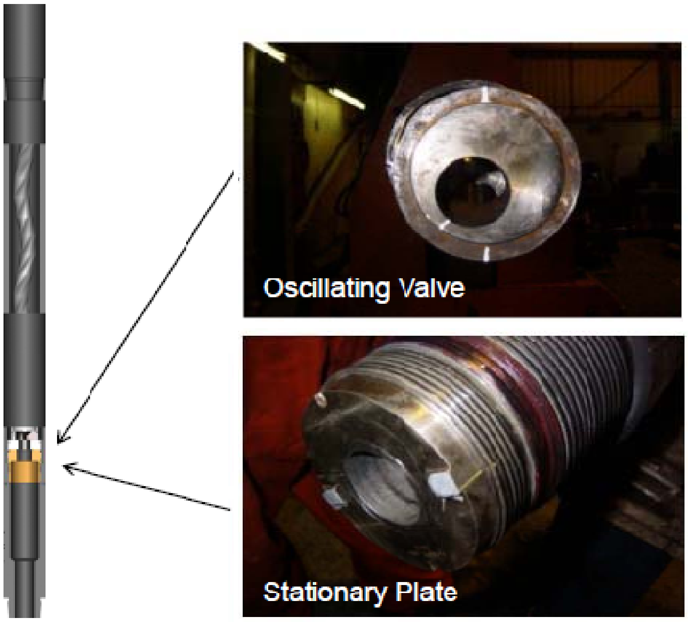
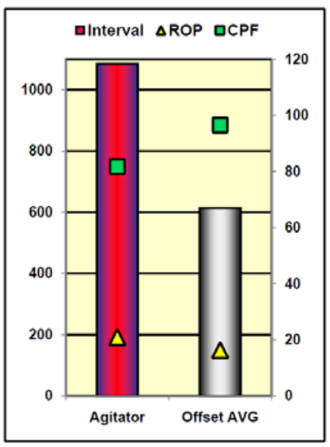
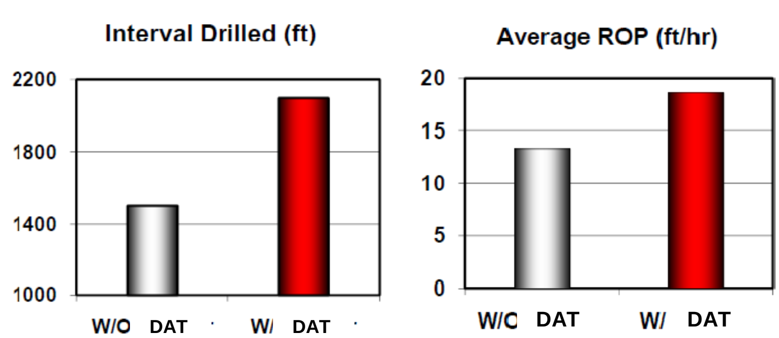


Figure 1. Components of a DAT.



Size	Bit Type	Mfg	WOB	RPM	Drive	In	Out	Drilled	Hours	ROP	CPF	Ti	To	MDC	Loc	B	G	ODC	RP
9.875	FX85D	SDBS	30	70	R	8105	9190	1085	52	20.9	81.67	1	2	WT	S	X	I	BT	PR
9.875	MSI813UPX	SB	30	65	R	8255	8760	505	17	29.7	75.76	2	2	WT	A	X	I	NO	PR
9.875	DSF816D	RH	30	75	R	8760	9504	744	54	13.8	102.16	2	3	CT	S	X	I	WT	PR
9.875	FX85D	SDBS	35	65	R	8644	9234	590	41.5	14.2	107.18	2	3	WT	A	X	I	CT	PR
					Offset Averages			613	37.5	16.3	96.52								

Figure 2.Performance of 8" DAT through vertical application in the Hosston Formation (Haynesville)

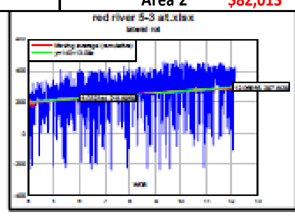


Size	Bit Type	Mfg	In	Out	Drilled	Hrs	ROP	Ti	To	MDC	Loc	B	G	ODC	RP	Inc In	Serial No	Run
6.75	DSR516M-B1	RH	12093	13595	1502	113	13.3	0	0	NO	A	X	I	NO	BHA	94.3	120143	1
6.75	DSR516M-B1	RH	13595	15693	2098	113	18.6	1	1	WT	A	X	I	NO	TD	88	120143	2

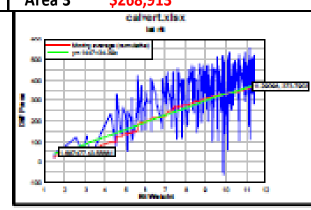
Figure 3. Performance Comparison for DAT run in the lateral section of the Haynesville

Drilling Areas	Area 1						Area 2				Area 3			
County/Parish	DeSoto	Sabine	Sabine	DeSoto	Red River	Desoto	Harrison	Harrison	Panola	Panola	Shelby	Shelby	San August.	Nacagdoch.
Curve DAT?	Yes	Yes	No	No	No	No	Yes	Yes	No	No	No	No	Yes	Yes
Bits in Curve	1 RSR613	1 FX73	2 UD516	1 FX731	3 RSR613	1 FX73	1 VD513	1 MDI711	2 UD 513	2 FX73	2 FM3731	2 HC406	1 SDI513	1 FX73
Bits in Curve			Fx73		2 UD513				FX73			2 FM3713		
Curve Feet Rot	1378	711	664	1683	1754	1255	512	1124	148	334	204	193	209	1220
Curve Feet Slide	913	648	228	315	594	161	703	871	653	481	485	498	361	515
Curve ROP FPH Rot	54	36	23	43	39	24	39	49	29	13	10	14	29	29
Curve ROP FPH Slide	22	21	20	18	11	12	22	26	20	18	10	11	28	11
Bits in lat	1 UD513	1 MSR516	1 UD513	4 UD513	4 UD513	2 UD513	1 VD513	1 UD513	1 UD513	3 UD513	4 UD513	3 FM3731,2 U513	1 SDI513	3 DS516
Lateral DAT?	Yes	Yes	Yes	No	No	No	Yes	Yes	No	No	No	No	Yes	Yes/No
Lateral Feet Rot	3512	3745	4087	4411	4419	4983	5655	4112	3791	4007	4218	3861	5363	4327
lateral Feet Slide	75	103	25	25	580	58	354	142	245	236	286	526	175	82
Lat ROP Rot	75	71.16	37	54	28	58	73	60	90	67	30	61	68	36
Lat ROP Slide	23.0	21.8	23.0	10.9	23.8	17.6	38.9	32.1	21.9	42.1	16.0	10.3	23.3	11.8
Curve Rot. M Grad*	18.7	15.3	2.9	11.1	40.4	6.4	7.7	5.9	12.3	13.9	18.2	2.9	10.6	4.3
Lateral Rot. M Grad*	9.5	17.8	1.7	34.4	14.2	17.6	15.0	11.9	15.4	11.0	26.0	11.1	10.2	16.8
Curve Rot/Slide%	60.1%	52.3%	74.4%	84.2%	74.7%	88.6%	42.1%	56.3%	18.5%	41.0%	29.6%	27.9%	36.7%	42.2%
Lateral Rot/Slide %	2.1%	2.7%	0.6%	0.6%	11.6%	1.2%	5.9%	3.3%	6.1%	5.6%	6.8%	13.6%	3.3%	1.9%
Hor. Displacement	5878	5207	5004	6434	7347	6457	7224	6249	4837	5058	5193	5078	6108	6144
Total Effective #Bits	2	2	3	5	6	3	1	2	3	5	6	6	2	4
Norm. Interval Cost	$350,198	$396,089	$439,193	$393,224	$636,727	$387,002	$288,200	$163,151	$249,694	$365,682	$829,379	$517,147	$294,462	$514,237
AVG. Area Savings Using DAT	Area 1	$77,157					Area 2	$82,013			Area 3	$268,913		

* "M" Grad Is a comparative reference slope derived from surface data where WOB vs Diff∆Psi data from rotating mode is plotted and Slope(M) is calculated.. The higher the slope value suggests more, and progressive frictional forces existed. For example Area 1, the Red River 5-3-Alt compares to be more efficient where M=9.5 then the M gradients for the area non-agitator wells (M= 34.4, 14.2, 17.6). Example graphs at right.

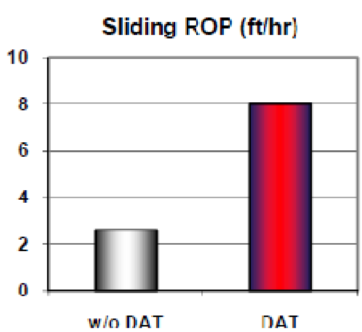


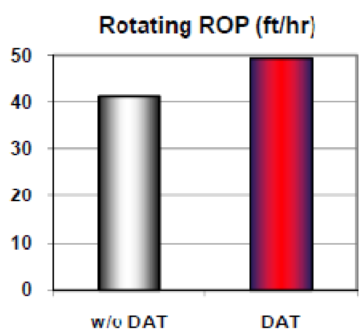
M=9.5 (Agitator)

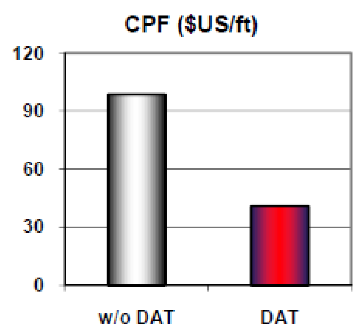


M=34.4 (Non Agitator)

Figure 4. Case study comparing performance benefits of DAT versus non-DAT through the directional section of the Haynesville.

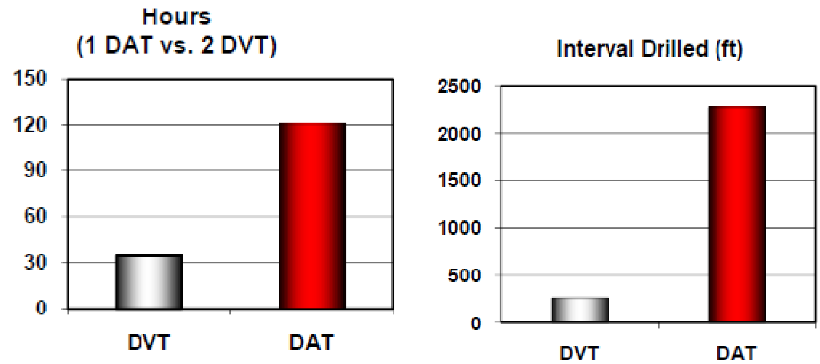






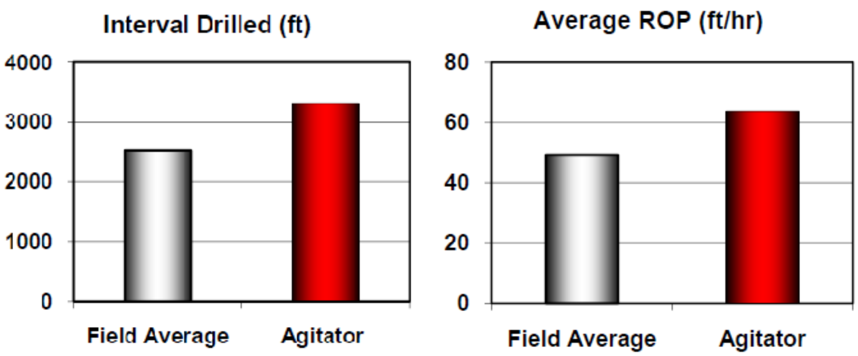
Performance While Sliding						
Runs	DAT	In (ft)	Out (ft)	Interval (ft)	Hrs	Avg.ROP (ft/hr)
4	No	9,334	12,774	446	170.5	2.6
2	Yes	12,774	15,707	192	24.0	8.0
Performance While Rotating						
Runs	DAT	In (ft)	Out (ft)	Interval (ft)	Hrs	Avg.ROP (ft/hr)
4	No	9,334	12,774	2,987	72.5	41.2
2	Yes	12,774	15,707	2,741	55.5	49.4

Figure 5. DAT Performance through Curve and lateral section of Eagle Ford



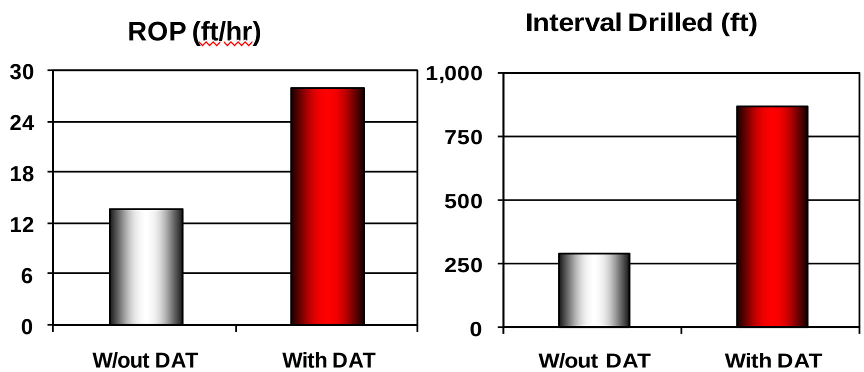
Tool size	Type	No of runs	Depth In	Depth Out	Interval(ft)	Hours	ROP (ft/hr)	Drive Type
4 3/4"	DVT	1	7935	8196	261	19.5	13.4	Motor
4 3/4"	DAT	4	8196	10480	2284	120.5	19	Motor

Figure 6. Performance Comparison of Drilling Agitator Tool vs. DVT in lateral application in the Barnett shale



	In	Out	Interval (ft)	Hours	ROP (ft/hr)
Field Average	8141	10660	2519	51.2	49.2
Agitator	7965	11280	3315	52	63.8

Figure 7. Offset Comparison in lateral applications in Barnett shale



DAT	Depth In (ft)	Depth Out (ft)	Drilled (ft)	Hours	ROP (ft/hr)
No	11546	11835	289	19.25	15
Yes	11835	12705	870	32.75	26.6

Figure 8. Performance Comparison through the horizontal section of the Barnett shale.

Agitator Well Comparisons							
WELL[1]	In (ft)	Out (ft)	Drilled (ft)	Hours	ROP (ft/hr)	Cost Per Foot[4]	Savings Per Well
Non-Agitator							
Well 1 - Pad 1 - Non-Agitator	1013	9731	8718	101	86.3	$13.98	
Well 2 - Pad 1 - Non-Agitator	1046	9425	8379	124	67.6	$16.88	
Well 3 - Pad 1 - Non-Agitator	975	9721	8746	134	65.3	$17.14	
Average	1011	9626	8614	120	72.0	$15.99	
SAVINGS PER WELL							$ -
Curve Agitator[2]							
Well 1 - Pad 1 - Curve Agitator	1010	11155	10145	125	81.2	$14.02	
Well 2 - Pad 1 - Curve Agitator	1000	10030	9030	98	92.1	$13.21	Curve Agitator
Average	1005	10593	9588	111.5	86.0	$13.64	vs
% Improvement					19%	17%	Non-Agitator
SAVINGS PER WELL							$ 22,500
Full Agitator[3]							
Well 1 - Pad 2 - Full Agitator	1025	12765	11740	104	112.9	$10.60	
Well 2 - Pad 2 - Full Agitator	1070	12778	11708	89	131.6	$9.54	
Well 3 - Pad 2 - Full Agitator	1050	14016	12966	113	114.7	$10.18	Full Agitator
Average	1048	13186	12138	102	119.0	$10.11	vs
% Improvement					65%	58%	Non-Agitator
SAVINGS PER WELL							$ 71,350

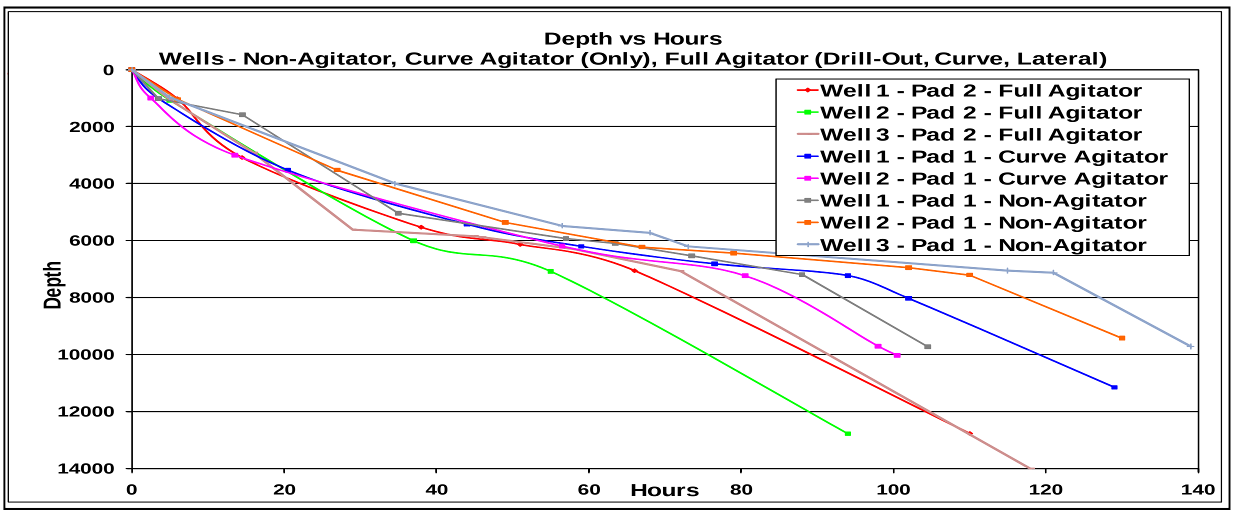


Figure 9. Case Study comparing benefits of DAT versus non-DAT through curve in the Barnett Shale