SPE-173678-MS

Cost Effective Solutions to Achieve Injection Post Toe Valve Failure

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This paper was prepared for presentation at the SPE/ICoTA Coiled Tubing & Well Intervention Conference & Exhibition held in The Woodlands, Texas, USA, 24–25 March 2015.

Abstract

The use of pressure-activated toe valves in a completion string is yet another innovative approach to completing a horizontal well. This technology eliminates the need for perforating guns prior to a multi-stage hydraulic fracturing (frac) operation. Subsequently, the operator can greatly reduce costs when the need for coiled tubing (CT), wireline (WL), or workover rig (WOR) is no longer needed on location to convey perforating guns.

However, when injection rate through the toe valve is not adequate for wireline pump-down operations, or the toe valve fails to open at all, the operator must revert back to conventional methods of perforating in order to achieve injection into the well and begin the frac operation. These failures immediately negate any of the cost savings the toe valves were designed to provide. This paper will review cost effective solutions, through the use of abrasive perforating, to quickly and efficiently perforate the toe stage and minimize non-productive time (NPT).

Most often, adequate pump-down rate is not achieved through the toe valve when debris or cement is lying across the tool, preventing it from opening or plugging off the ports. Prior to perforating, a motor and bit run is common to verify that the well is clean down to plug back total depth (PBTD). This requires a minimum of two round trips with coiled tubing or a workover rig. Two different methods of abrasive perforating have been used to benefit both conventional plug and perforate and frac sleeve completions (sometimes referred to as “baffles”). Several case histories will be presented to explain how a single trip in hole, utilizing a motor BHA and abrasive perforator in tandem to clean and perforate the toe stage, can minimize costs compared to several round trips using the conventional method with perforating guns. Additionally, we will explore an innovative approach to abrasively perforate the toe stage through frac sleeves where minimal ID’s pose a problem with conventional methods of perforating.

Abrasive perforating technology, in conjunction with other innovative tools, adds a wide range of flexibility for today’s complex horizontal wells. Utilizing this technology, problems such as toe valve failures can be addressed in a safe and cost effective manner.

Introduction

Pressure-activated toe valves, or toe initiator valves (TIV), improve efficiency for operators by providing an interventionless means of beginning a mulit-stage frac operation. Benefits to installing a TIV in the completion string are its operational simplicity and versatility in that it can be run in both plug and perf and frac sleeve style completions. When the TIV functions properly, it eliminates the need for an initial perforating run. However, like all mechanical tools, failures are inevitable. When a TIV fails to open or when injection rates are inadequate to pump down WL guns or frac balls, intervention work is now required. Abrasive perforating offers an effective means of providing communication between the wellbore and formation for both plug and perf and frac sleeve completions. Several case histories will be presented that discuss how abrasive perforating is an efficient and cost effective solution after a TIV failed to function properly.

Benefits and Functionality of a TIV

A standard plug and perf completion requires that injection for frac operations be established by some means of intervention when the casing is cemented and the system is closed. In a vertical well, WL can run perforating guns with the assistance of gravity. However, the options available to create perforations in a horizontal well are TCP on coiled tubing or jointed pipe, or tractor-conveyed perforating. The cost and logistics required for intervention are costly and highly inefficient when compared to using a TIV. In fact, one Eagle Ford operator reported cost savings in excess of $100,000 when utilizing a TIV and no pre frac intervention work was required.

Operationally, a TIV performs a simple function. The tool is installed at the toe of the completion string and is activated by a pressure increase on surface. When the operator is ready to begin frac operations, bottom-hole pressure (BHP) is increased by pressuring up on the production casing to a pre-set value that is determined by either a rupture disc or shear pin value. When the downhole pressure exceeds the value of the rupture disc or shear pins, an internal sleeve will shift to expose ports as a conduit for wellbore fluid to now enter the annular area of the casing (Figure 1). If adequate injection through the ports is enough, the operator may now complete the first stage. If the TIV fails to open at all, the wellbore still remains a closed system and intervention work is imminent.

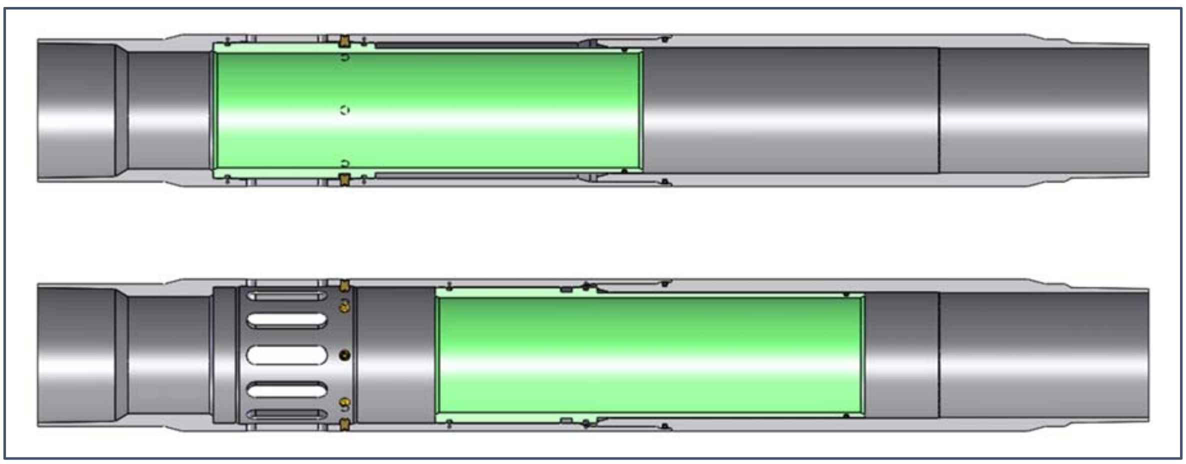


Figure 1 – Toe valve in the closed and open position

TIV Failure & Solutions

For the purpose of this paper, a TIV failure is defined as any unplanned pre-frac intervention work that is required after a TIV is installed in the completion string. TIVs can fail due to a number of different reasons. One reason for failure is a mechanical malfunction. Reasons for a mechanical failure can be caused by any number of variables including: downhole conditions, manufacturing defects, or damage to the tool during installation.

Another reason for failure is when the TIV opens, but planned injection rates cannot be achieved. There are a few possible reasons for why this may occur. The first reason is higher than expected fracture initiation pressures. This can be caused by the formation or cement sheath if the TIV was cemented in place. This, however, can be alleviated if acid can be circulated down through the TIV to dissolve cement or formation. Another, and more common, reason why the desired injection rates cannot be achieved is due to debris (cement) in the wellbore. This happens when injection rate through the TIV is established, but while bringing the frac rate up, the pressure climbs and the TIV screens out completely. When this occurs, an initial cleanout run with coiled tubing or jointed pipe is required to remove debris from the wellbore, followed by a second trip with perforating guns.

Whatever the reason for a TIV failure, the benefits of running a TIV are eliminated when problems arise and intervention is necessary. There are a few options for dealing with a TIV that has not opened or provided inadequate injection rate.

The first and cheapest option is to pump down WL guns to create perforations which may assist in reaching higher injection rates. However, the injection rate will still need to be high enough to carry guns to the desired depth. The fluid velocity needed to carry guns in a horizontal wellbore can vary, but typically a minimum fluid velocity of 565 feet per minute is necessary. The second WL option is to tractor guns down to the desired perforating depth. This operation would be required if there was limited or no injection rate to pump down WL guns. However, if the TIV failed due to a screen out caused by debris or cement, a cleanout run will be necessary and a WL tractor may not be feasible. While these forms of intervention are less expensive than mobilizing coiled tubing or jointed pipe, it is still an unexpected cost for the operator and can be exponential when an entire frac spread is waiting on stand-by.

The second option to create perforations for achieving the required injection rate is tubing-conveyed perforating (TCP) using coiled tubing or jointed pipe. This is required when there is very limited injection rate, or if a wireline tractor cannot reach the target lateral depth. With coiled tubing or jointed pipe on location, operators have the option to simply run in hole and perforate with TCP guns. However, knowing that debris or cement in the wellbore is the suspected cause of the TIV failure, the safest option to successfully place the first frac would be to perform an initial cleanout run before perforating. This method traditionally requires two trips in hole. For a plug and perf completion, a motor and mill run followed by a TCP run are the standard practice. In a frac sleeve system, a wash nozzle BHA can be run through the baffles, as long as there is enough clearance for the wash nozzle to pass through the smallest baffle ID. After the wash nozzle run, a second run with TCP guns would be required to perforate the lowest point in the well that TCP guns could pass. Albeit frac sleeve systems have varying internal diameters based on the operator’s well design, TCP charges may or may not be able to pass below certain baffles. Consequently, some of the lower frac stages may have to be abandoned.

While intervening is an unwanted cost, the ability to begin frac operations and avoid losing any pay zones are the main concerns. However, there is still a way to reduce the cost of getting operations back on track. Utilizing abrasive perforating, in conjunction with cleanout BHAs, can make the two trip process of wellbore cleanout and perforating a one trip procedure. With this ability to cleanout and abrasively perforate in one trip, the coiled tubing or workover unit charges, along with any possible frac stand-by charges, will be minimized.

Abrasive Perforating 101

Abrasive perforating (sometimes referred to as abrasive jetting or hydrajetting) is a method of perforating that uses an abrasive-laden fluid exiting through nozzle(s) at high velocities to erode through steel, cement, and formation in a short period of time. The abrasive material and fluid medium typically used is 100 mesh sand and fresh water or brine water, respectively. Larger mesh sands may be used but 100 mesh is preferred because it extends the life of the perforator. Abrasive perforating is not new to the industry, but advancements in material and tool technology have since given service companies and operators the ability to develop and optimize solutions for problems currently being faced in today’s oil and gas wells. When comparing perforations made by abrasives to perforations created by guns, studies have shown that abrasive jetting reduces near wellbore friction by up to 92%, subsequently lowering treating pressures and reducing screen outs.

Because abrasive jetting uses erosion instead of shaped charges as seen in TCP guns, many benefits can be seen including:

- The ID of the casing is clean and clear of metal burrs
- The perforation tunnels are clear of debris
- The near wellbore erosion creates a "tear drop" effect that minimizes obstructive debris near the tunnel entry point (figure 2)
- No added stress or compressive damage to the formation
- Deep penetration into formation
- Safer to use and does not require any special certifications or extra safety policies

When talking about perforations, penetration depth and entry-hole diameter (EHD) are major topics of discussion. Although an array of perforator nozzle size(s), configurations, and sand slurry concentrations can be used, testing has shown that using 0.125 inch diameter orifices on the perforator, a 0.5 pound per gallon (ppg) sand slurry concentration, and a pump rate of 0.5 BPM per orifice gave optimal and practical results for the scenarios discussed in this paper. At this rate, an exit velocity of ~550 ft/sec is achieved; and with minimal standoff between the perforator and ID of the casing, an EHD of ~0.4 inches is created. The subject surrounding the depth of penetration that is achievable by abrasive perforating is still a matter yet to have a definitive answer. While many field trials and technical papers have been written on this subject, respected authors in the field of sand jet perforating, such as J.S. Cobbett and A.D. Nakhwa, would suggest that abrasive perforating can achieve a greater penetration depth compared to perforating guns. A.D. Nakhwa et al documented, in SPE paper 107061, a total penetration depth of 27 inches in 10 minutes of pumping time (figures 3 & 4).

Next, we will discuss two different methods of abrasive perforating that were utilized to perforate the toe stage in the two aforementioned completion designs.

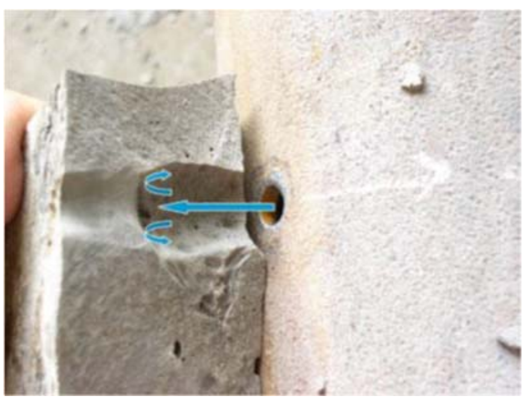


Figure 2 – Tear drop effect from errosion

Figure 3 – Penetration depth from center of casing

Figure 4 – Penetration depth

Abrasive Perforating with Plug and Perf

When a TIV fails in a plug-and-perf completion, a motor and abrasive perforator BHA is assembled in tandem on coiled tubing. The purpose of this “bypassing” perforator BHA is to perform a motor cleanout to PBTD (figure 5a) and then perforate the toe stage in a single trip (figure 5b). After the perforations are made, a motor run with the same BHA back down to PBTD will ensure that all the sand used to perforate is circulated out of the wellbore (figure 5c). The perforator is a proprietary design that uses two drop balls and internal sliding sleeves to accomplish the dual function of: flow-thru→perforate→flow-thru. The flow-thru operation allows the use of tools that are positioned below the perforator, i.e. mud motor. The orifice phasing on the perforator is a standard six (6) spf and 60° phasing. Another important aspect to this BHA is the use of an extended reach tool (ERT) that is placed between the motor and perforator. As the lateral sections of horizontal wells continue to get longer, utilizing an ERT in the BHA is practically a necessity. For the extended lateral wells that we see in today’s industry, vertical pipe weight is simply not enough to deploy these BHA’s down to PBTD. This aspect is important because, although ERT’s can be run with a motor and mill to perform a cleanout, it is not yet industry standard to run ERT’s with a gun assembly to assist in getting the string to planned depth. If excessive friction is encountered with the gun assembly, costly pipe-on-pipe friction reducers are used or the guns are set off above planned depth. If the two runs, motor and TCP, can be combined into one single operation, cost and efficiency are optimized and the operator can minimize intervention costs and NPT.

Figure 5a – Motor cleanout down to PBTD. Blue arrows indicate the flow of fluid

Figure 5b – The first ball is dropped and seated in the perforator to redirect flow out of the perforator

Figure 5c – The second ball is dropped and seated in the perforator to redirect flow back to the motor

Abrasive Perforating with Frac Sleeves

The advent of the TIV brought about new completion technology widely used today in oil and gas wells. Frac sleeve systems use a series of tapering internal diameter ball seat valves strategically positioned in the well that create a restriction in the wellbore relative to the ID of the ball seats. These systems were developed to directly compete with a plug-and-perf style completion and are available with both cement and open-hole style isolation methods. One major selling point for these systems is the expedited rate at which the well can be frac’d. By eliminating a wireline run between stages, the downtime between frac stages is at a minimum. Although these systems have many advantages, the industry has also seen the disadvantages to frac sleeve completion systems. In regards to the writing of this paper, we will be discussing one of these disadvantages further. In order to pump the initial frac ball down to the first seat, the well must be converted from a closed system to an open system. In order to do that, a TIV is placed at the toe of the casing string and activated in the way aforementioned. If the TIV functions as designed, the first ball can be pumped down and seated on the stage one landing baffle. Once seated, pressure is increased on surface to shear pins inside the baffle and open ports that expose the wellbore to the casing annulus. The frac operation may now commence. However, if the TIV fails, the system is still considered to be closed and intervention work is necessary. Intervention options may include:

- Drilling out all the ball seats using coiled tubing or jointed pipe and then perform a standard plug and perf operation. This option is not economical and very time consuming
- Run in with TCP guns on coiled tubing and run through the restricted ID's as far as possible. The depth achieved may be limited by friction or gun OD vs. ball seat ID. There is a possibility that stages are forfeited. Again, this option can be uneconomical if stages are abandoned
- Run in with a shifting tool that mimics a frac ball, seat it on the ball seat and attempt to pressure up on the casing to shift the seat. This option is more economical but success rates can vary
- Run in with a specially designed slim-hole abrasive perforating system that can utilize an ERT and perforate below the first ball seat. Doing this provides a means of injection and the initial frac ball can then be pumped down. This option has proven to be economical and has a high success rate

With all intervention options considered, the slim-hole abrasive perforating system can be the most economical as a means of achieving injection into the well. Coiled tubing size and BHA size are determined based on the minimum restriction in the wellbore. An example of a slim-hole BHA running through sleeves can be seen in Figure 6. The number of orifices used in the perforator are determined by the anticipated pump rate that can be achieved. The perforators encompass an internal sliding sleeve that give the tools "flow-thru" capabilities. This allows ERT's to be used below the perforator in order to reach planned depth. Once on depth, a ball is dropped from surface to activate the perforator. Enough perforations are made at the toe to achieve the proper injection rate necessary to propel the first ball down to seat.

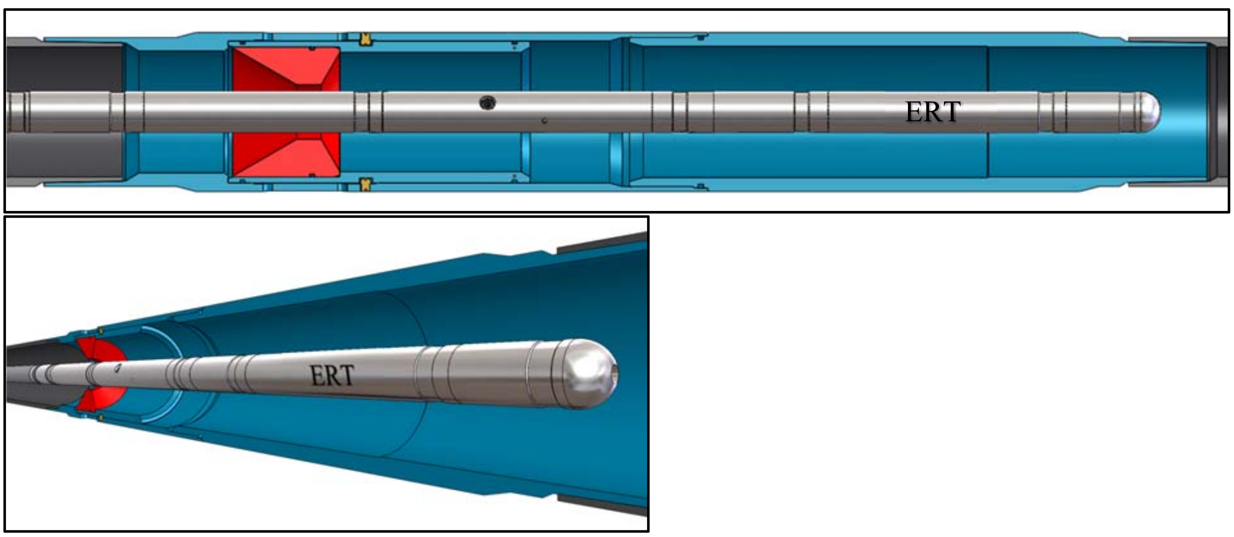


Figure 6 – Slim-hole perforator BHA running through a ball seat

Case Histories

Each case history presented below will describe a TIV that failed to function properly in a horizontal well, and a one-trip abrasive perforating system that was used to establish injection and ultimately begin frac operations. These case histories describe the work of two different operators in the Eagle Ford Shale for both plug and perf and frac sleeve completions. Additionally, of the three case histories discussed below, each well had a different TIV that was supplied by a different major service provider.

Case History #1

Synopsis

An operator had a TIV installed in the well at 18,157' for a standard plug and perf operation. During the initial well prep, the TIV failed to open with multiple attempts made at pressuring up on the casing. Due to the unknown cause of failure, the operator wanted to perform a motor and bit cleanout down to PBTD before perforating. To minimize intervention costs, the decision was made to rig up coiled tubing and the one-trip bypassing perforator system. See Figure 7 for complete BHA diagram.

Job Parameters

Casing Specs:	5-1/2" 23# x 5-1/2" 20#, P110
PBTD:	18,203 ft
TVD:	11,650 ft
TIV Depth:	18,157 ft
Lateral Length:	5,185 ft
Coiled Tubing:	2-3/8" OD
BHA:	2.88" Motor BHA with 3.50" OD Perforator
Fluid:	Fresh Water
Sand:	0.5 ppg, 100 mesh
Cut Depths:	17,936; 17,988; 18,039; 18,091; 18,143 ft
Number of Perforations Created:	30 total, 5 clusters @ 6 spf
Injection Rate Achieved After Perforating:	9 BPM @ 6,200 psi (max rate attempted)

Results

The bypassing perforator BHA was RIH with all flow initially going through the ERT, motor, and bit. The operator wanted to clean the well past the TIV. PBTD was tagged, verifying that the well was clear of debris. The first ball was dropped from surface and seated in the perforator to redirect flow from the motor to the perforator. A total of 150 bbls sand slurry was pumped through the perforator to create 30 total perforations from 17,936' to 18,143'. When all the perforations were made, a second ball was dropped from surface and seated in the perforator to redirect flow from the perforator back to the ERT, motor and bit. The BHA was run back down to PBTD to clean out any residual sand and circulate the wellbore clean. When the coiled tubing and BHA reached surface, an injection test was performed down the casing to verify the perforations were open. The injection test was successful with a maximum attempted rate of 9 BPM at 6,200 psi. The frac spread was moved onto location and pumped the first stage without any complications. With the ability to clean out and perforate in one trip, the operator reported a cost savings of $40,000 when compared to the conventional two trip method.

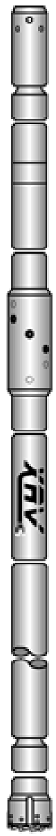
Tool OD (in.)	Tool ID (in.)	Tool Diagram	Length (ft.)	Description	Connection (Make-Up Torque)	Drop Ball
3.25	1.00		1.77	Coil Connector/ Back Pressure Valve f/ 2.38" O.D. Coil	2-3/8" PAC Pin Dn (2,300 Ft/Lbs)	
2.88	0.69		2.24	Hydraulic Disconnect	2-3/8" PAC Box Up (2,300 Ft/Lbs) x 2-3/8" PAC Pin Dn (2,300 Ft/Lbs)	3/4" (.750)
3.50	0.53		3.55	Bypassing Abrasive Perforator w/ (6) Ports @ 60˚	2-3/8" PAC Box Up (2,300 Ft/Lbs) x 2-3/8" PAC Pin Dn (2,300 Ft/Lbs)	9/16" (.563) 5/8" (.625)
2.88			1.65	XRV Extended Reach Tool	2-3/8" PAC Box Up (2,300 Ft/Lbs) x 2-3/8" PAC Pin Dn (2,300 Ft/Lbs)	
2.88			13.52	Titan Supermax Motor w/ Power Plus Power Section	2-3/8" PAC Box Up (2,300 Ft/Lbs) x 2-3/8" PAC Box Dn (2,300 Ft/Lbs)	
4.50			0.45	Bear Claw Bit	2-3/8" PAC Pin Up (2,300 Ft/Lbs)	
		Overall Length:	23.18			

Figure 7 – 2.88" Motor BHA with 3.50" OD Abrasive Perforator

Case History #2

Synopsis

The operator had a TIV installed at 17,405' below 75 sliding sleeves from 13,482' – 17,355'. The last sleeve had an ID of 2.76". During the initial well prep, the TIV failed to open at all. Multiple attempts were made to pressure up on the well and open the TIV. The call was made to rig up coiled tubing and the one trip cleanout and slim-hole abrasive perforating system. Pre-job modeling showed that the coiled tubing would again need the assistance of an ERT. Knowing this, the perforator was designed with a ball drop sleeve to accompany the ERT below the perforator. See Figure 8 for a complete BHA diagram.

Job Parameters

Casing Specs:	5-1/2” 23# x 5-1/2” 20#, P110
PBTD:	17,452 ft
TVD:	10,877 ft
TIV Depth:	17,405 ft
Lateral Length:	6,233 ft
Min Baffle ID:	2.76”
Deepest Baffle:	17,355 ft
Coiled Tubing:	2.00” OD
BHA:	2.125” Slick Abrasive Perforator BHA with ERT
Fluid:	Fresh Water
Sand:	0.5 ppg, 100 mesh
Cut Depths (CT Depth):	17,345; 17,341; 17,336 ft
Number of Perforations Created:	18, 3 clusters @ 6 spf
Injection Rate Achieved After Perforating:	6 BPM @ 7400 psi

Results

The 2.0” coiled tubing and slim-hole abrasive perforator BHA was ran below the last sliding sleeve. A ball was dropped from surface and seated in the sliding sleeve to direct flow from the ERT to the perforator. A total of 45 bbls sand slurry was pumped through the perforator to create a total of 18 perforations. When all perforations were made, they picked up above the top perforation, shut in the backside, and performed a low rate injection test through the coiled. The test was successful at establishing injection confirming that perforations were made.

The coiled tubing was pulled out of hole and an injection test was performed down the casing upon reaching surface. The injection test was again successful so coiled tubing was rigged down and the frac spread was rigged up. The first ball was dropped to open the first set of sleeves. A positive indication of the sleeves shifting was not observed but the operator knew that this could be linked to a couple factors due to past experience, i.e. frac balls breaking. In addition to any frac sleeves being open, the operator knew they had at least 18 perforations so the stage one frac was pumped as designed without any further complications. The operator was happy with the abrasive perforating system because it was the most cost effective intervention solution to establish injection.

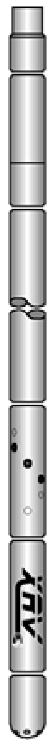
Tool OD (in.)	Tool ID (in.)	Tool Diagram	Length (ft.)	Description	Connection (Make-Up Torque)	Drop Ball
2.13	1.00		0.20	Weld-On Type Connector	1-1/2" AM MT Pin Dn (700 Ft/Lbs)	
2.13	1.00		1.70	Dual Back Pressure Valve	1-1/2" AM MT Box Up (700 Ft/Lbs) x 1-1/2" AM MT Pin Dn (700 Ft/Lbs)	
2.13	1.00		5.00	Straight Joint	1-1/2" AM MT Box Up (700 Ft/Lbs) x 1-1/2" AM MT Pin Dn (700 Ft/Lbs)	
2.13	0.53		2.00	Spiral Abrasive Perforator w/ (6) Ports @ 60°	1-1/2" AM MT Box Up (700 Ft/Lbs) x 1-1/2" AM MT Pin Dn (700 Ft/Lbs)	1/2" (.500)
2.13			1.39	XRV Friction Reduction Tool	1-1/2" AM MT Box Up (700 Ft/Lbs) x 1-1/2" AM MT Pin Dn (700 Ft/Lbs)	
2.13			0.30	High Velocity Wash Nozzle	2-3/8" PAC Box Up (2,300 Ft/Lbs)	
		Overall Length:	10.59			

Figure 8 – 2.13 in OD Abrasive Perforating BHA with ERT

Case History #3

Synopsis

One operator in South Texas had a well installed with two TIVs and 24 open-hole frac sleeves. Numerous attempts were made to open the toe valves with the frac crew but were unsuccessful. An attempt to open the TIVs by increasing the hydrostatic pressure with 11.6 ppg $CaCl_2$ fluid was also unsuccessful. With 1.50” coiled tubing, the operator made a final attempt to open the deepest frac sleeve with a shifting tool but to no avail. The 11.6 ppg $CaCl_2$ was then circulated out of the well using the 1.50” coiled tubing unit. The unit was released so the situation could be reevaluated.

Initial thoughts were to utilize 1.50” coiled tubing and run in hole with 1.69” OD TCP guns to create perforations below the 1.70” ID baffle. After firing the TCP guns, the plan was to drop the ball for the hydraulic disconnect and leave the TCP assembly in the hole. This was due to swelling concerns of the guns and the possibility of not being able to pull it back through the 1.70” baffle. However, pre-job modeling showed that TCP guns might not reach the desired perforating depth due to wellbore friction.

Ultimately, the operator decided to utilize the one trip cleanout and slim-hole abrasive perforating system. The objective was to run 1.50” coiled tubing with a 1.50” slick OD abrasive perforating assembly (Figure 9). The BHA was built to have 2 nozzles spaced at 45° phasing in order to perforate 6 total holes below the final 1.70” baffle at 13,239 ft. It was calculated that with an EHD of ~0.4 inches, 6 perforations was sufficient to achieve the desired injection rate of 5-10 bpm to successfully pump the first frac ball to seat. Pre–job modeling showed that the coiled tubing would need the assistance of an ERT to reach the desired perforation depth (Figure 10). Therefore, the perforating tool was designed with a ball drop sliding sleeve that would allow all initial flow to travel through the ERT below the perforator.

It was also known that for the 1 bpm of rate required to perforate two holes at each stop, that sand would not be adequately circulated out of the wellbore. Therefore it was decided to only perforate 6 holes to limit the amount of sand we introduced into the wellbore. A procedure was written up to successfully pump the sand into formation after perforating.

Job Parameters

Casing Specs:	5-1/2”, 23#, P110
PBTD:	13,518 ft
TVD:	7,928 ft
TIV Depth:	13,425 ft & 13,449 ft
Lateral Length:	5,086 ft
Min Baffle ID:	1.70 in
Deepest Baffle Depth:	13,239 ft
Coiled Tubing:	1.5” OD
BHA:	1.5” OD Slick Abrasive perforator BHA with ERT
Fluid:	Fresh Water
Sand:	0.5 ppg, 100 mesh
Cut Depths:	13,315; 13,330; 13,345 ft
Number of Perforations Created:	6 total, 2 spf @ 45° phasing
Injection Rate Achieved after Perforating:	8 bpm @ 5,100 psi

Result

The 1.5” CT and slim-hole perforator was RIH to a depth of 13,360 ft. The BHA was then pulled to the first desired perforation depth. Once on depth, a ball was dropped and the perforating sleeve was opened for perforating operations to begin. A 0.5 ppg concentration slurry of 100 mesh sand was pumped for 20 minutes at depths 13,345, 13,330 and 13,315 ft, creating a total of 6 perforations. Following the procedure, the sand was then carefully pumped into the formation. Once the sand had been pumped away, the coiled tubing was pulled out of hole. Once on surface the coiled tubing pump began injection into the well at 8 bpm at 5,100 psi. Days later the frac crew returned and the first ball was successfully pumped down to begin frac operations. No stages were abandoned and the entire frac sleeve system was utilized.

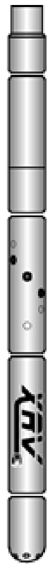
Tool OD (in.)	Tool ID (in.)	Tool Diagram	Length (ft.)	Description	Connection (Make-Up Torque)	Drop Ball
1.50	0.75		0.15	Weld-On Type Connector	1" AM MT Pin Dn (350 Ft/Lbs)	
1.50	0.58		1.08	Dual Back Pressure Valve	1" AM MT Box Up (350 Ft/Lbs) x 1" AM MT Pin Dn (350 Ft/Lbs)	
1.50	0.43		0.88	Abrasive Perforator w/ (2) Ports @ 45°	1-1/2" AM MT Box Up (700 Ft/Lbs) x 1-1/2" AM MT Pin Dn (700 Ft/Lbs)	1/2" (.500)
1.50			1.20	XRV Extended Reach Tool	1" AM MT Box Up (350 Ft/Lbs) x 1" AM MT Pin Dn (350 Ft/Lbs)	
1.50	0.34		0.31	Wash Nozzle	1" AM MT Box Up (350 Ft/Lbs)	
		Overall Length:	3.62			

Figure 9 – 1.50 in OD Abrasive perforating BHA with ERT.

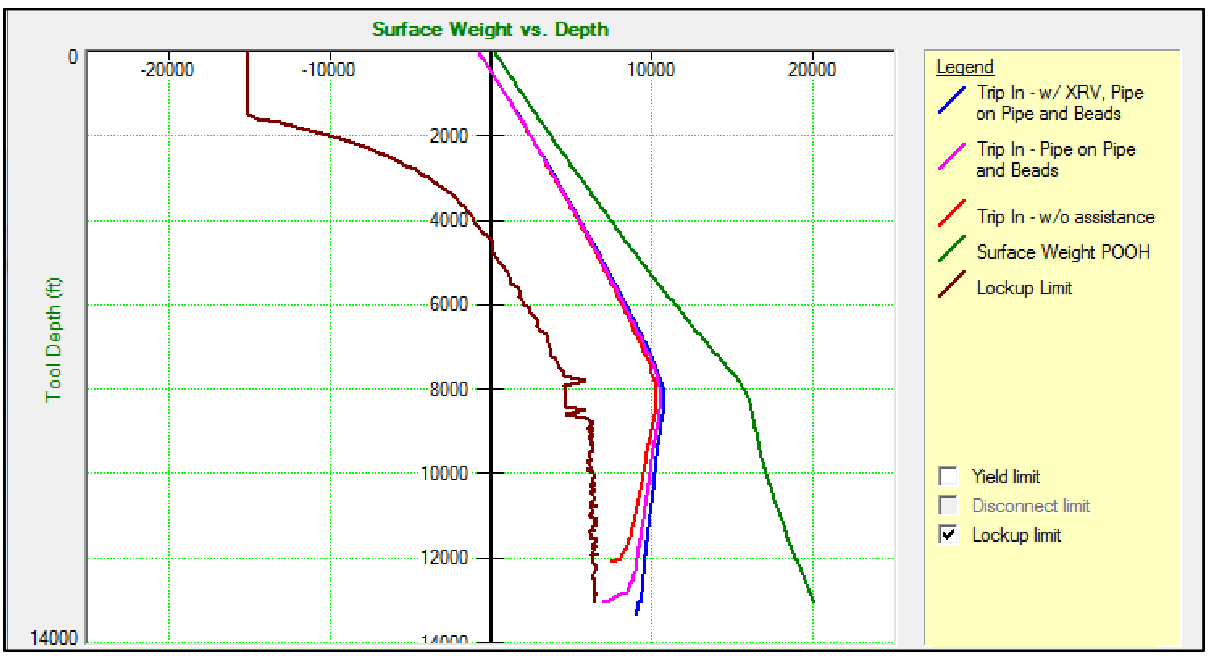


Figure 10 – Pre-Job modeling showing friction lock-up with and without the extended reach tool.

Conclusion

Pressure activated toe valves have provided operators with a means of reducing costs by eliminating the need for pre-frac intervention work for horizontal multi-stage frac completions. However, when a toe valve fails to function properly, the casing is a closed system and intervention with wireline, coiled tubing, or jointed pipe will be required. By utilizing a one trip cleanout and abrasive perforating system, operators can minimize the cost of the unplanned intervention operation.

The benefits to utilizing a one trip abrasive perforating system include:

- The ability to clean the wellbore and perforate with a single trip in hole
- Options available for both plug and perf and frac sleeve completions
- The ability to utilize an extended reach tool for extended lateral depths
- Clean perforations, free of casing burrs and debris in the perforation tunnels
- Lower breakdown pressures
- Deep penetration depth
- A safer form of perforating
- Maximum formation exposure. No forfeited pay zones
- One operator estimated a cost savings of $40,000 when comparing the motor and abrasive perf system to the conventional two trip system (motor run followed by a TCP run)
- Estimated savings in excess of $100,000 when comparing the slim-hole abrasive perforating system, in frac sleeve completions, to abandoning zones or drilling out the existing baffles

Acknowledgements

The authors would like to thank Derek Finkel of Thru Tubing Solutions for creating the animated drawings presented in this paper. Lastly, the authors would like to thank the Oil & Gas companies for allowing presenetation of their case histories.

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