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Abrasive Perforating via Coiled Tubing Revisited

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Abstract
In certain formations in the Western Canadian Sedimentary Basin tortuosity resulting from conventional perforating gives rise to high near well bore friction pressures during hydraulic fracturing operations and the resultant increased likelihood of premature screen out.

This paper will discuss the benefits of Abrasive Perforating via coiled tubing and present a number of case studies including vertical and horizontal wells. A number of previously published papers and laboratory investigation has suggested that significant benefits may arise from abrasive perforating; actual well data will be used to test these hypotheses. This paper will present empirical data showing reductions in near well bore friction of up to 92%. Furthermore, benefits of Abrasive Perforating via coiled tubing and overcoming the operational challenges will be discussed.

Introduction
Abrasive perforating is not a new technology; it has in fact been around since the 1960's[1]. The benefits of this existing technology have recently been highlighted with data from the Western Canadian Sedimentary Basin. The particular formation used in this case study is a blocky siltstone with interlaminated fine grained sands. Conventional Tubing Conveyed Perforating (TCP) resulted in high near well bore friction pressures causing premature screen out of the hydraulic fracture treatment. By abrasive perforating the formation via coiled tubing, near well bore friction pressures were significantly lower. The hydraulic fracture treatments were placed at lower pressures without further problems.

Background Information
Compared with explosive perforating, Abrasive Perforating is more time consuming and typically raises costs[1]. An average Abrasive Perforation operation can cost $80,000, however the cost of a premature sand screen out can cost up to $500,000 in cleanouts, re-perforating, lost time, and lost production.

Using coiled tubing to convey the Abrasive Perforating tool has certain advantages over jointed tubing. Coiled tubing is more efficient in a live well situation lowering the amount of tripping time compared to jointed tubing. With jointed tubing, snubbing equipment would be required, lengthing the time to remove tubing from the well bore after the perforations are created.

Using Abrasive Perforating has certain safety advantages over conventional perforating. There are no explosives to handle, or the risks associated with running TCP guns into a well bore.

The Abrasive Perforating Equipment
BJ Services Company Canada provided a 60.3mm Coiled Tubing Unit (for two cases), 50.8mm Coiled Tubing Unit, two high pressure pump trucks, slurry batch mixer, sand and gellant.

Thru Tubing Solutions provided the entire bottom hole assembly (BHA).

Figure 1 Shows the Perforating BHA diagram.

Below is a brief description of the BHA components.

Coil Tubing Connector - Connects the BHA to the coiled tubing withstanding both tension and torsional forces.

Dual Flapper Back Pressure Valves – Prevents flow back up the coiled tubing.

Hydraulic Disconnect – A ball activated separation sub that will release the BHA in a stuck situation.

Swivel – Allows the BHA to freely rotate in the well

Eccentric Orienting Sub – Orient the Abrasive Perforator.

Crossover- Connect to the Abrasive Perforator sub allowing for proper orientation.

High Velocity Abrasive Perforator sub – Orifices placed in the cutting head generate the velocity required to create the perforations.

Rounded Nozzle – Acts as a rounded guide for the BHA into the well bore, as well as a means of washing down while running into the well.

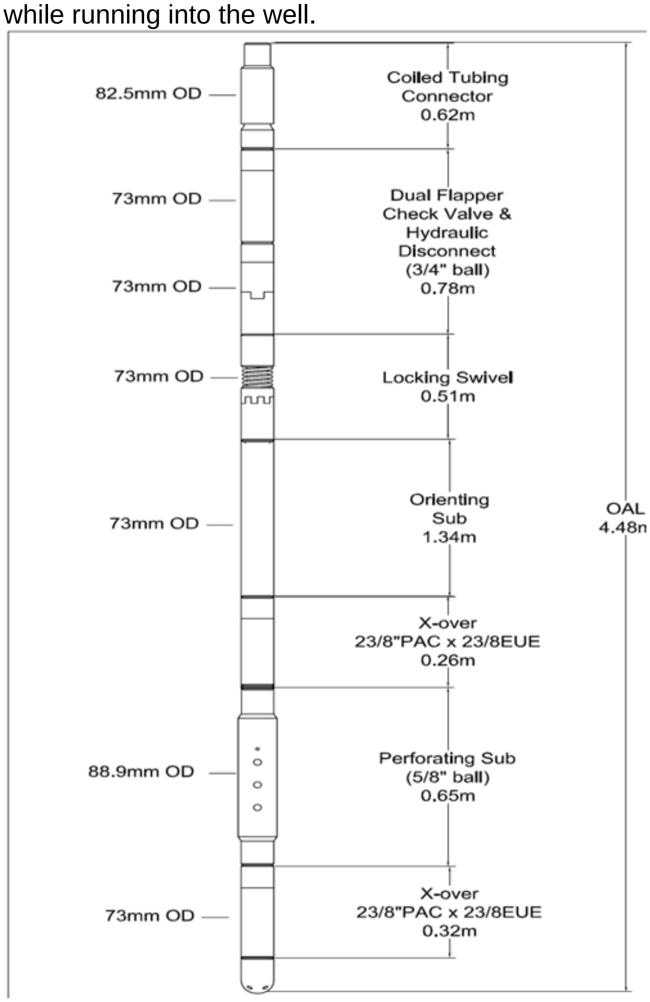

Figure 1 Abrasive Perforating BHA

Operational Summary

The process begins with attaching the BHA to the coiled tubing, followed by a complete, pull and pressure test. The wellhead is opened and coiled tubing is run into the hole, while circulating fluid at minimum rates to maintain positive pressure in the coiled tubing. As the coiled tubing is being run in the hole, the perforating slurry is being blended in the batch mixer. The gelled fluid has a viscosity of 110cp or greater in order to maintain sand suspension through the pumps and to the BHA. The sand used in this operation is sized at 100mesh, and blended at a concentration of 120kg/m^3. Once the coil is on perforation depth a 15.8mm ball is launched. The ball is landed in the Perforator diverting flow to the jets. Once indications show a pressure increase, the perforator is operational and the sand slurry is pumped. The volume of sand slurry needed to complete each perforation set is 5m^3. The slurry is pumped at 480l/min to obtain the maximum velocity through the orifices creating a pressure drop of 15MPa. Once the specified slurry volume is circulated, the slurry rate is reduced lowering the coiled tubing pressure, and pulled up to the next perforation interval. The process is repeated until the desired number of perforations are created. After the perforation operation is complete the coiled tubing is run into the hole to plug back or a predetermined depth past the perforations. Once on depth, an engineered sand cleanout is completed to remove the excess sand and gelled fluid from the well bore. Coiled tubing is pulled out of the hole once the well bore is clean.

Case Histories

Each case history is based on data from the same well bore and formation. Near well bore friction is determined as follows:

$$f_{\mathrm{Total}} = LTP - ISIP$$

Total friction= Last treatment pressure - ISIP

ISIP= instantaneous shut in pressure at surface.

$$f_{\mathrm{NWB}} = f_{Total} - f_{pipe}$$

$$f_{\mathrm{NWB}} = (LTP - ISIP) - f_{pipe}$$

Near well bore friction= total friction – pipe friction

Pipe friction is calculated to be 1MPa in a vertical well and 2MPa in a horizontal well. The fracturing system used has been optimized and proven to be effective for the formation being stimulated.

Case #1 Vertical well, 114.3mm 20.09kg/m L-80

Perforation type - TCP guns

Perforations at 2633m to 2635m measured depth.

Minifrac Analysis

Volume Pumped:	10m^3
Fluid Injected into Formation:	4% KCl Water
Hydrostatic Pressure	23.6MPa
Average Treating Pressure:	29.1MPa
Average Treating Rate:	1.4m^3/min
Surface ISIP:	21.6MPa
BH ISIP:	45.2MPa
Fracture Gradient:	19.1KPa/M
Last Treatment Pressure:	27.8MPa

Table 1 Minifrac analysis Case #1 TCP guns

Near Well Bore Friction=(LTP-ISIP)-Pipe friction
(27.8MPa-21.6MPa)-1MPa= 5.2 MPa

Perforation type – Abrasive Perforations
Perforations at 2527m to 2529m measured depth.

Minifrac Analysis

Volume Pumped:	10m3
Fluid Injected into Formation:	2% KCl Water
Hydrostatic Pressure	24.1MPa
Average Treating Pressure:	23.7MPa
Average Treating Rate:	0.9m^3/min
Surface ISIP:	22.6MPa
BH ISIP:	46.7MPa
Fracture Gradient:	19.2KPa/M
Last Treatment Pressure:	24.0MPa

Figure 3 Minifrac analysis Case #1 Abraisive Perforation

Near Well Bore Friction=(LTP-ISIP)-Pipe friction
(24.0MPa-22.6MPa)-1.0MPa= 0.4 MPa

Summary Case #1
TCP gun perforations had a well bore friction of 5.2MPa. Abrasive Perforating had a well bore friction of 0.4MPa. The Abrasive Perforating reduced the well bore friction by 4.8MPa or 92 %.

Case #2, Horizontal well, 114.3mm 20.09 kg/m L-80

Perforation type - TCP guns
Perforations at 3055m to 3057m (2460m TVD) measured depth

Minifrac Analysis Section

Volume Pumped:	10m^3
Fluid Injected into Formation:	2% KCl Water
Hydrostatic Pressure	24.4MPa
Average Treating Pressure:	46.0MPa
Average Treating Rate:	0.6m^3/min
Surface ISIP:	20.3MPa
BH ISIP:	44.7MPa
Fracture Gradient:	18.2KPa/M
Last Treatment Pressure:	46.0MPa

Figure 4 Minifrac analysis Case #2 TCP guns

Near Well Bore Friction=(LTP-ISIP)-Pipe friction
(46.0MPa-20.3MPa)-2MPa= 23.7MPa

Perforation type – Abrasive Perforation
Perforations at 3039m to 3040.5m (2460m TVD) measured depth

Minifrac Analysis Section

Volume Pumped:	10m^3
Fluid Injected into Formation:	2% KCl Water
Hydrostatic Pressure	24.4MPa
Average Treating Pressure:	30.7MPa
Average Treating Rate:	0.8m^3/min
Surface ISIP:	25.0MPa
BH ISIP:	45.6MPa
Fracture Gradient:	18.5KPa/M
Last Treatment Pressure:	30.0MPa

Figure 5 Minifrac analysis Case #2 Sand Jet Perforation

Near Well bore Friction=(LTP-ISIP)-Pipe friction
(30.0MPa-25.0MPa)-2.0MPa= 3.0MPa

Summary Case #2
TCP gun perforations had a well bore friction of 23.7MPa. Abrasive Perforating had a well bore friction of 3.0MPa. The Abrasive Perforating reduced the well bore friction by 20.7MPa or 87 %

Case #3, Horizontal well, 114.3mm 20.09 kg/m L-80

Perforation type - TCP guns
Perforations at 2830m to 2832m measured depth

Volume Pumped:	10 m^3
Fluid Injected into Formation:	2% KCl Water
Hydrostatic Pressure	24.4MPa
Average Treating Pressure:	43.8MPa
Average Treating Rate:	0.8m^3/min
Surface ISIP:	22.5MPa
BH ISIP:	41.7MPa
Fracture Gradient:	18.5KPa/M
Last Treatment Pressure:	42.6MPa

Figure 6 Minifrac analysis Case #3 TCP guns

Near Well Bore Friction=(LTP-ISIP)-Pipe friction
(42.6MPa-22.5MPa)-2.0MPa= 18.1MPa

Perforation type – Abrasive Perforation
Perforations at 2828m to 2829m measured depth

Minifrac Analysis Section

Volume Pumped:	$10m^3$
Fluid Injected into Formation:	2% KCl Water
Hydrostatic Pressure	23.9MPa
Average Treating Pressure:	24.5MPa
Average Treating Rate:	$0.7m^3$/min
Surface ISIP:	21.1MPa
BH ISIP:	45.0MPa
Fracture Gradient:	18.8KPa/M
Last Treatment Pressure:	24.5MPa

Figure 7 Minifrac analysis Case #3 Abrasive Perforation

Near Well Bore Friction=(LTP-ISIP)-Pipe friction
(24.5MPa-21.1MPa)-2.0MPa= 1.4 MPa

Summary Case #3
TCP gun perforations had a well bore friction of 18.1MPa. Abrasive Perforating had a well bore friction of 1.4MPa. The Abrasive Perforating reduced the well bore friction by 16.7MPa or 92%.

Effects of Abrasive Perforating on Coiled Tubing and related equipment
Coiled tubing samples where taken before and after an abrasive perforation job was complete, showing insignificant wear from sand erosion. The minimum wall thickness measured on both samples was associated with external abrasion not associated with the abrasive perforating operation. The rotating joint and coiled tubing reel treatment iron were inspected before and after the operation, and there was no measurable wear due to the abrasive perforating operation.

Conclusion
1. The data presented supports the theory stated in a number of SPE papers[1,2,3] that; Abrasive Perforating can reduce near well bore friction.
2. In wells with high near-wellbore friction, and/or horizontal completions, Abrasive Perforating via coiled tubing is a viable alternative to tubing conveyed perforating (TCP) or conventional wire line perforating.
3. Although abrasive perforating is more expensive then conventional TCP perforating, the cost to refracture an interval due to a premature screen out can be 6 times or greater, then the cost of the initial abrasive perforation operation.
4. Constant process optimization is helping to bring down the costs and increase the efficiency of the abrasive perforation operation via coiled tubing.

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