OPENHOLE HORIZONTAL PROPPANT FRACTURING UTILIZING A NEW HYRAJET FRACTURING METHOD

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ABSTRACT

This paper presents case histories from openhole horizontal completion projects using a new hydrajetting fracturing process to place multiple fractures. The new hydrajetting fracturing method can be applied to cased or openhole situations, and does not require mechanical isolation between treatment points. The method works well with both acid and proppant fracs. The case histories illustrate recent improvements in coiled tubing equipment that have made it possible to reduce the completion cycle time, and safely perform coiled tubing fracturing with proppants in an openhole horizontal setting.

BACKGROUND AND INTRODUCTION

Until recently, a common belief was that horizontal completions would eliminate the need for hydraulic fracture stimulation even in low-permeability formations that required hydraulic fracturing in vertical completions. Initially, drilling-induced damage was thought to be the main problem with many of the poorly producing horizontal completions. Simple damage removal treatments, such as acid washing the wellbore with a variety of cleaning tools typically conveyed on small diameter coiled tubing, were employed to remove the skin damage associated with drilling. This damage was typically thought to be mudcake and filtrate invasion.

The success rate for coiled tubing acid washing was very low. The mudcake from the drilling process was being removed, but some other mechanism was the controlling factor for poor horizontal well performance in low-permeability reservoirs. Closer examination of the low-permeability formations that have been historically hydraulically fractured from vertical completions revealed that vertical permeability anisotropy was the rule rather than the exception.

Vertical completion techniques were able to contact and commingle these multiple layers of varying permeability by simply perforating where the vertical well intercepted the porosity/perm layer. Further enhanced connectivity was achieved by hydraulic fracturing. Examination of whole cores from several low-permeability reservoirs revealed that many times the formation is layered or laminated with recurring vertical permeability barriers that are too thin to be detected with openhole logging tools because of the limited resolution (measured in feet) of openhole logs. Hydraulic fracturing of the horizontal wellbore is the most common method chosen to provide vertical connectivity across the payzone. Predictable horizontal well performance can be achieved if the hydraulic fracture initiation points can be focused at specific initiation points and optimal spacing between fractures can be obtained. A new technique has been developed to efficiently accomplish pinpoint initiation and spacing of hydraulic fractures along horizontal wellbores.

HYDRAJET FRACTURING

Theoretical background and practical applications of hydrajet fracturing have been described in previous papers. This patented process has been successfully applied on three continents in a variety of wellbore configurations. The process has been successfully applied in openhole horizontals, horizontal slotted liners, and cemented cased horizontal wellbores.

The technique is essentially a combination of three separate processes: (1) hydrajetting, (2) hydraulic fracturing (through tubing), and (3) co-injection down the annulus (using separate pumping equipment). After the wellbore has been cleaned, either drillpipe, tubing, or large OD coiled tubing is used to deploy the bottomhole tool assembly (BHA). The BHA is run to the first desired fracture initiation depth, which is typically at the toe. A low-concentration sand-laden cutting stage is pumped down the tubing and through the hydrajet nozzles in the BHA at high pressure. The bottomhole and annulus pressures are kept below fracture-initiation pressure by allowing return circulation out of the annulus while the cutting stage creates perforating tunnels into the formation. Once the perforation tunnels have been formed by the jetting action, the annulus is shut-in and injection is established on the annulus. The annulus rate and pressure are controlled such that the bottomhole pressure is maintained just below fracture initiation pressure. Because of the Bernoulli effect caused by the jetting action, the pressure inside the jetted cavities will be hundreds of psi higher than the wellbore pressure causing fracturing only at that location along the lateral.

After fracturing is initiated, a conventional fracturing treatment (proppant fracturing or acid fracturing) is placed. The fracturing stages are typically patterned after treatments that would be used to stimulate a vertical completion. The annulus rate is regulated to compensate for sacrificial wellbore leakoff. All of the fracturing slurry or acid is pumped down the tubing and jetted into the jetted cavities connected to the far field fracture plane. After the fracturing treatment is flushed down the tubing, a back-pressure tubing control valve is activated and the tubing is stripped from the well under pressure to the next fracture initiation point.

The process begins again with a cutting stage followed by the fracture initiation stage, and finally the fracture-extension stage. By repositioning of the Bottom Hole Assembly (BHA), multiple fractures are placed until the entire lateral wellbore is stimulated.

LARGE DIAMETER COILED TUBING

Because hydrajet fracturing is a live annulus treatment (no packer) that requires pressure and flow control of the well and stimulation fluids at all times, large-diameter coiled tubing offers many desirable characteristics. With the aid of a surface choke manifold, circulation (both conventional and reverse) can be carried out continuously as pipe is moved in and out of the well. The stripping and blow-out prevention equipment that is an integral part of coiled tubing operations can be remotely controlled by the coiled tubing operator. A high pressure connection to the treatment string is made only once as compared to a jointed pipe operation where multiple connect and reconnect operations have to be performed. Rapid movement of the treating string from one fracture initiation point to the next is possible with coiled tubing. From a health, safety, and environment standpoint, coiled tubing is more user friendly than a rig assist snubbing unit. Personnel are not subjected to pulling a wet string, and multiple potential pinch point occurrences inherent with picking up, making up, breaking out, and laying down jointed tubing are avoided by using coiled tubing. These factors make large-diameter coiled tubing a more efficient and safer alternative to conventional snubbing type equipment.

Fit for purpose coiled tubing units, specifically designed for quick rigup and fitted with large-diameter coiled tubing, are being introduced that add to efficiency by minimizing footprint on location, as well as rigup time. Using larger-OD coiled tubing, operators have placed propped fractures to approximately 8,000 ft at treating rates up to 10 bbl/min. A combined workstring, consisting of jointed pipe connected to a surface string of coiled tubing, will enable these multi-stage treatments to be placed in much deeper reservoirs, effectively doubling or tripling the depth capability of a single coiled tubing string. For many applications this improvement would provide the flexibility, speed, and safety inherent to coiled tubing operations with a spool of only a few thousand feet, and jointed pipe would not be exposed to high treating pressures at surface.

SOUTHEAST NEW MEXICO OPENHOLE HORIZONTAL CASE HISTORY

Delaware sand formations of the Delaware Basin in SE New Mexico typically consist of fine to medium coarse grained sandstones layered with siltstones and shales in thick depositional sequences. Minor brown limestone and dark-gray, silty shale beds are present. The three main Permian age productive intervals are the Bell Canyon, Cherry Canyon and Brushy Canyon formations. Gross thickness of the Delaware sands can approach 1,000 ft with many sub-divisions of porosity members occurring in the sequences. Calculated water saturations from openhole logs on hydrocarbon productive intervals typically range between 40 and 65%. High water cuts are not unusual. Hydraulic fractured vertical completions often have difficulty staying out of adjacent high-water-saturation zones above and below the targeted hydrocarbon zones because the weak siltstone layers are effective permeability barriers but do not provide rigorous stress containment of the hydraulic fracture treatments.

One of the wells in this formation was completed with a 5.5 in. cemented casing in the vertical section. The horizontal segment was a 4.75-in. openhole with a 1,800 ft lateral, at an average true vertical depth of approximately 4,500 ft. As with several former horizontal completions in this reservoir, the well was a sub-par producer and the operator did not believe that conventional stimulation technology offered a cost-effective solution. Alternative completion methods, such as cementing a liner and pumping multistage fracturing treatments were too costly for the enhanced oil recovery (EOR) values expected from these wells. In nearby fields, the use of inflatable packers to provide isolation for proppant fracturing had proven to be a high-risk/low-reward option. After reviewing the new hydrajet technology and its successful application in similar reservoirs, the operator chose to try the process as a “last ditch” effort to make the horizontal drilling program in this field an economic success.

Early in the fourth quarter of 2002, the candidate well was selected for this trial application of hydrajet fracturing technology. The lateral had been drilled in the general direction of the least principal horizontal stress so that fractures formed would tend to be generally transverse to the wellbore. This fracture direction in a horizontal well usually provides the maximum stimulation benefit and provides the highest EOR.

The candidate well was a few months old and had produced at a fairly steady rate of 43 to 45 BOPD during that time. It was decided that the treatment would place five small fracture stimulations at evenly spaced locations along the lateral. There was some concern that significantly larger fracture stages might communicate with water-producing zones below. A snubbing unit was used to wet-stripout the required number of pipe joints (2 3/8-in. N-80 tubing) between fracturing stages to reposition the BHA. **Table 1** shows the pumping schedule used for Fractures #1 and #2 treatments.

All five fracturing stages were pumped within an 8.5-hour period, providing a cost-effective way to deliver precise fracture stages at desired locations along the wellbore with no mechanical or gel-plug isolation needed. Post-hydrajet fracturing production was very satisfactory to the operator, with an average 95 BOPD produced during the first 90 days after treatment. This well was still producing at a steady rate of 65 BOPD seven months after the treatment.

Following the success of this stimulation treatment, the operator immediately decided to spud two additional wells that had been suspended because of poor production from earlier horizontal completions. In early 2003, these two additional wells were drilled and the hydrajet fracturing stimulation process was incorporated into the initial completion plan. On both of the wells, 2 3/8-in. coiled tubing was used as the treating string with the same type of BHA as that used on the first well. In addition to providing a safer working environment, compared to snubbing/wet-stripping pipe joints, the new process also shortened the time between fracturing stages, and the five stages were completed in just over six hours. **Figure #1** illustrates the efficiencies that can be obtained by employing large diameter coiled tubing.

The fluid volumes, proppant volumes, and pumping rates (both tubing and annulus rates) were similar on all three wells. Well 2 appeared to have poorer quality reservoir rock, and was producing 70 BOPD after 45 days and appeared to be holding steady. Well 3 was producing 170 BOPD after 30 days and falling very slowly. By performing the hydrajet fracturing stimulations as part of the initial well completions of wells 2 and 3, total well costs were significantly reduced compared to Well 1. With an effective stimulation technique for these openhole horizontals, the drilling program in this field is continuing. At a future date, more complete data on this project may be released for publication.

Table 1
Pumping Schedule for Fractures #1 and #2

Stage No.	Stage Description	Tubing Side Non-Crosslinked Guar Gel (gal)	Tubing Side Borate Crosslinked Gel (gal)	Annulus Side Non-Crosslinked Guar Gel (gal)	Tubing Side Total Clean Volume (gal)
1	Circulate	1,000	0	0	1,000
2	Circulate and jet jetting fluid	2,000	0	0	3,000
3	Pump jetting fluid	1,550	0	0	4,550
4	Close backside	1,000	0	0	5,550
5	Instant Shut-in Pressure	0	0	0	5,550
6	Prepad	1,000	0	0	6,550
7	Pad	0	4,000	988	10,550
8	1 lbm/gal slurry	0	1,000	247	11,550
9	2 lbm/gal slurry	0	1,000	247	12,550
10	4 lbm/gal slurry	0	1,000	247	13,550
11	6 lbm/gal slurry	0	1,000	247	14,550
12	Flush	1,555	0	384	16,105
13	Shut down, move to next position	0	0	0	16,105
14	Circulate and jet jetting fluid	1,500	0	0	17,605
15	Pad	0	4,000	988	21,605
16	1 lbm/gal slurry	0	1,000	247	22,605
17	2 lbm/gal slurry	0	1,000	247	23,605
18	4 lbm/gal slurry	0	1,000	247	24,605
19	6 lbm/gal slurry	0	1,000	247	25,605
20	Flush	1,555	0	384	27,160
21	Shut down, move to next position				

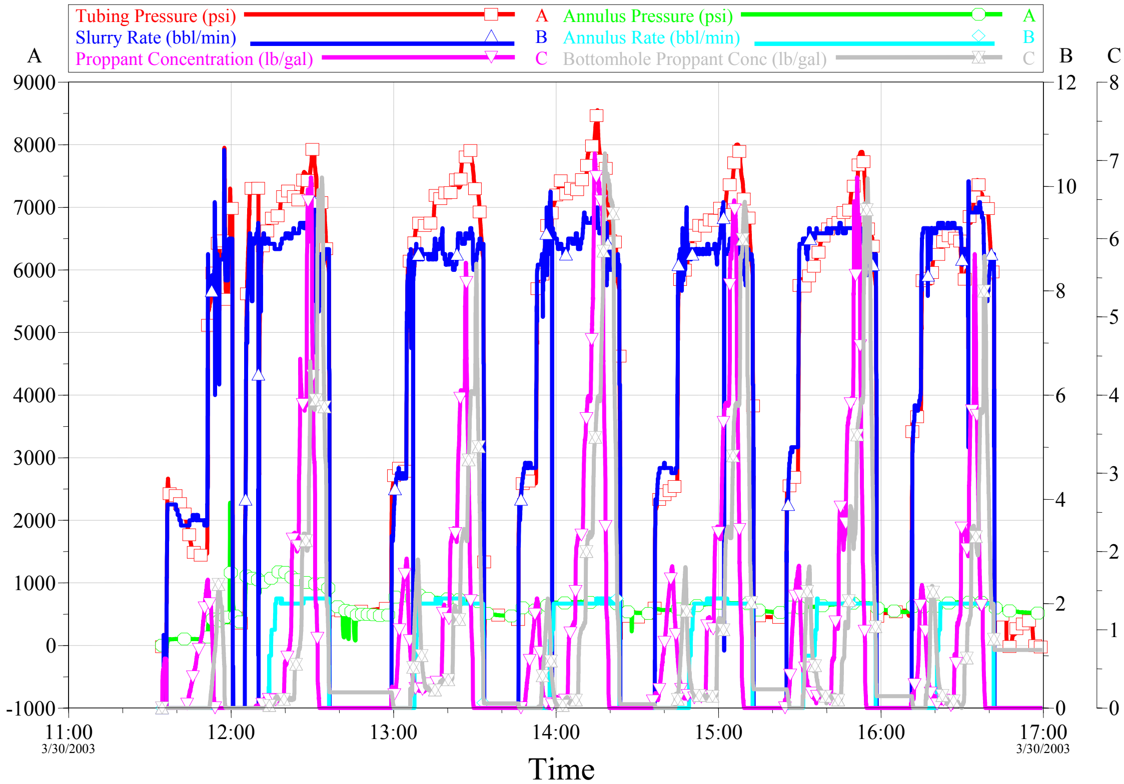

Figure 1 - HydraJet Fracturing Treatment Using Large Diameter Coiled Tubing