PRECISELY PLACED PROPPED FRACTURES IN HORIZONTAL WELLS COMPLETED WITH UNCEMENTED LINERS

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ABSTRACT

Until recently, there has not been an effective method for efficient proppant-fracturing of horizontal wells initially completed using uncemented liners, whether preperforated, slotted, or perforated after installation. A new technology that incorporates hydrajetting, fracturing, and simultaneous injection down the treating string and the annulus now enables the operator to fracture-stimulate such completions, placing separate propped fractures at selected locations along the lateral. This process is also applied in wells completed with barefoot open holes and cemented liners. This paper specifically addresses the use of this new technique in non-cemented liner applications. Because several separate fractures can be placed with a single well intervention and often within the same day, the cost is far less than previous techniques, as well as more effective.

In some cases, the hydrajet-fracturing technology has been applied as a last-hope effort to make poor producers into economic completions. After the technology proved successful, operators were able to continue drilling in areas that had been at or near the point of abandonment because of ineffective stimulation treatments.

This process has been proven in numerous wells in the United States without a liner in the openhole section. This paper focuses on the application to wells with non-cemented liners and includes a case history from northern Asia.

BACKGROUND

A common misperception in the industry has been the belief that horizontal completions usually eliminate the need for the hydraulic fracture stimulations that vertical completions (even in the same reservoir) normally require. Today however, we realize that many natural horizontal completions may actually be less productive than hydraulically-fractured vertical wells in the same field or reservoir. Although drilling damage along the lateral may still be a significant factor limiting horizontal well productivity, reservoir conditions can also play a major role.[1]

Although multilayered reservoirs are often poor candidates for horizontal completions, operators sometimes overlook the fact that many moderate and low-permeability zones contain layers of varying porosity and permeability. In the general scope of its geology, these multilayered zones may be viewed as if they can produce as a single layer. Unexpected vertical permeability barriers are often too thin to be detected by conventional well logs. As a result, these barriers are not considered in modeling that uses computerized reservoir production simulators.

Some low-permeability reservoirs are only economic when they contain a natural fracture system present to improve effective permeability and produce more prolifically. A horizontal lateral will improve the probability of intersecting dense *swarms* of these fractures compared to the probability of intersecting fractures with vertical or partially deviated wells. For some reservoirs, these fractures are damaged during continued drilling; after completion, they never produce as effectively as expected from the drilling show or drilling fluid losses. In some fields, if the first horizontal does not encounter enough natural fracturing to provide commercial production rates, additional lateral legs are drilled in different directions.[2]

For any of these reasons, many horizontal wells are drilled that will not be commercial unless the operator can achieve effective stimulation after completion or as part of the final completion. Unless the completion method incorporates an effective cemented liner, conventional stimulation technology is usually ineffective, or effective but too costly. If a producing formation is a highly acid-soluble carbonate zone, conventional technology has a reasonable success rate; a low percentage of commercial success has been witnessed in most other lithologies. In many moderate-permeability zones and most low-permeability zones, economic constraints force operators to attempt completing horizontal wells as bare open holes or with some type of a non-cemented liner.

The decision between lower well costs vs. a more expensive completion (requiring greater ultimate economic recoveries) presents a “Catch-22.” This risk analysis has historically tilted toward lower well costs. However, less costly horizontal wells (generally openhole completions) historically do not offer economical stimulation options when production is unacceptable; there were seldom any effective methods for stimulation beyond some near-wellbore damage removal. An innovative new technology, hydrajet fracturing, now offers hope for economic stimulation (beyond damage removal) for a large group of these wells. By varying the technique or the bottomhole assembly (BHA), this process can be applied in horizontal completions with bare open holes, cemented liners, and many non-cemented liners. This paper will only address wells with non-cemented liner completions.

HYDRAJETTING

The industry has long recognized that hydrajetted perforations or slots can create communication paths between the wellbore and the reservoir rock that are many times more effective than explosive shape-charge perforations.[3] This new hydrajet-fracturing process takes hydrajetting to a new level of application and incorporates the process into a one-trip, continuous, perforate-and-fracture (perf-and-frac) process, which adds only minutes and very low additional cost to the fracturing operation, while avoiding the greater expense of separate perforating operations. Clean, nondamaged, effective perforation tunnels allow this new method to initiate a hydraulic-fracture system without near-wellbore problems such as tortuosity or excessive multiple fractures. With this process, the jetting action starts the treatment, initiates the fracture geometry, and is (normally) continued until the desired fracturing stage has been completed for each selected location where a propped or acidized fracture will be placed.[4-8]

FRACTURE PLACEMENT

Although it is clear that openhole liner completions can be hydraulically fractured using proppant-fracturing or fracture-acidizing, the challenge is in finding ways to achieve *adequate* stimulation results at *acceptable* cost. Traditional technology methods usually result in the uncontrolled generation of numerous hydraulically induced fractures that suffer from one or both of these maladies:

- Created fractures are too numerous to grow to adequate length or width.
- Fractures are poorly distributed along the lateral, usually congregated in one area (or a few areas) where the formation is weak, or near the heel where pressure is higher during the fracturing process.

For optimum production enhancement, a fracturing-stimulation program should result in a limited number of discrete fractures that are widely separated and well distributed along the horizontal (**Fig. 1**). Unfortunately, this result is often presumed to be the probable outcome from fracturing non-cemented liner completions if the fluid exit points along the lateral are controlled. Realistically, **Fig. 2** illustrates the most common result observed from actual data, such as that obtained from tiltmeter or passive microseismic monitoring during real time or from post-fracturing surveys.

Historically, in horizontal openhole wells, most post-fracturing survey methods, when used alone, are inconclusive and subject to many nonunique interpretations. In recent years, more trustworthy monitoring techniques, such as tiltmeters and passive seismic monitoring, appear to support the conclusion that no matter what wellbore trajectory is drilled with respect to the least-principal stress planes, the initial fracture initiation will be in the longitudinal direction, or parallel to the axis of the wellbore. If the least-principal stress vector is essentially perpendicular to this axis, the growth pattern will continue mostly along that same plane, but if more than approximately 15° off, multiple parallel fractures may form instead of the desired single fracture at each fluid-entry location. If the least-principal stress vector is essentially parallel to the wellbore axis, the dominant far-field preferred fracture plane (PFP) will be transverse (perpendicular) to the wellbore. However, the physical action of removing rock in drilling the borehole usually causes the near-wellbore zone to have an altered stress orientation. The borehole expansion can become the dominant effect on fracture initiation, whereby initial formation breakdown occurs parallel to the wellbore. This fracture plane is more resistant to width growth than fractures in the direction of the far-field PFP. This resistance causes pressures inside the fracture adequate to initiate a fracture or multiple fractures that grow and extend parallel to the far-field PFP.

Even if only a single PFP fracture is initiated (the most desirable condition), that fracture is not likely to be closely aligned with the fluid entry point through the liner. Placement is most likely to occur at the weakest point in the rock exposed to the initial longitudinal fracture. If there are several similar points of weakness along the face of this longitudinal fracture, multiple parallel (transverse) fractures are the most probable result.[9] Operators have found that efficiently cementing the liner in the wellbore reduces this problem.[10] In softer formations, it is often possible to completely overcome this problem by dense clustering of the perforations. It appears that as rock hardness increases, this method becomes less dependable. The authors speculate that rock and permeability damage caused by explosive charge perforating increases as rock hardness increases.

If too many fractures are propagated, the width and length of each is reduced as the number increases. The closer the proximity of these parallel fractures, the more intensely they compete for width, and many may be terminated by this competition. In a proppant-fracturing slurry, small widths will more easily be plugged, possibly to the point of very early screen-out. With fracture acidizing, this multiple fracturing is less likely to be clearly evidenced by real-time pressure data, but the very short etched fracture lengths will severely limit the stimulation benefit. The primary objective is to create fractures where they are needed, and *only* where they are needed. If they do not cause early termination of the stimulation treatment, multiple fractures in close proximity to each other can improve the initial stimulation response. However, they provide little additional cumulative production beyond the very early producing time following the treatment.

In openhole horizontal wells without a liner, many operators will use a high-rate, large-volume openhole fracturing-stimulation attempt in which fluid is simply bullheaded into the open hole. Typically, such an operation will produce extreme multiple fracturing, with most of the treating fluid going to multiple fractures that are mostly within a small area near the heel section or at some area of mechanical weakness along the lateral. This essentially leaves the rest of the interval untreated. With injection pressures highest near the heel of the horizontal, it is most common to see. The fractures will rarely be uniformly distributed along the lateral, but their location is often dictated by the location of weaknesses or flaws in the reservoir rock, with open natural fractures as the most obvious such flaw. Low-pressure zones with good permeability, as well as fractures induced by drilling operations offer additional locations of weak zones that can allow for multiple fracture initiations. In some cases, operators have shot perforations at selected intervals to enhance the creation of fractures at those locations and improve the distribution of fractures along an openhole lateral. This practice has had very limited success.

If the primary need for fracture stimulation is only to communicate multiple vertical layers with the wellbore, longitudinal fractures are often desired, and the wellbore azimuth will be intentionally drilled parallel to the PFP. For these longitudinal fractures, a higher degree of success is possible for fracturing through a non-cemented liner completion using high injection rates and limited number of perfs to aid fluid distribution. Because the fracture *length* of this system is along the axis of the wellbore, there is a very limited degree of stimulation that can be achieved. For lower permeability reservoirs, or if trying to communicate to far-field fracture swarms, fractures that are transverse to the wellbore axis offer much higher stimulation rewards and significantly larger reservoir drainage volume for each wellbore. In many reservoirs, this technique still may not always be effective due to excessive multiple fractures.

DESCRIPTION OF HYDRAJET-FRACTURING PROCESS

A review of the past 15 years of drilling horizontal wells provides the following observations:

- Many horizontal wells need hydraulic fracturing stimulation to become commercial.
- Without an effectively cemented wellbore, fracture stimulation technology seldom delivers effective stimulation within the economic limitations of the well.
- More than 85% of horizontals drilled in North America have been completed without cemented liners (even if Austin Chalk completions are ignored, this number may still be valid).
- Uncontrolled multiple fracturing is a major reason for the lack of stimulation success.
- More control over how and where hydraulic fractures are initiated is needed.
- The process that selectively places fractures individually provides the best results.
- The process must offer a very low possibility of tools becoming stuck in the lateral.
- The process must be less costly and more reliable than available mechanical isolation techniques.

A new stimulation process for horizontal wells can achieve all the goals listed above. Because the theory and application methods for this patented stimulation technique have been discussed[2,4-8] in earlier papers, this paper will only include a brief discussion of the process. The method is essentially a unique combination of three separate processes: hydrajetting, hydraulic fracturing (through tubing), and co-injection down the annulus (using separate pumping equipment). In practice, the proppant-laden slurry (or live acid) has been pumped through the tubing, with annulus injection primarily serving to pressurize or add clean fluid to the fracturing system.

Unfortunately, not all horizontal wells needing fracture stimulation are currently candidates for this hydrajet-fracturing process. For example, a liner in the lateral having a small ID can limit the size of the treating string and the BHA, which can restrict the injection rate. If the treatment is to be more than a squeeze, the bottomhole rate must be adequate to extend and widen a hydraulic fracture. After the wellbore has been cleaned, either drill pipe, tubing, or large-OD coiled tubing (CT) is used to deploy the BHA.

Abrasives may not always be required during the initial jetting of perforation tunnels for a bare, openhole completion unless the formation is very hard. However, with any type of liner in the lateral section, the initial jetting action (before fracture initiation) must include solid abrasives to perforate through the liner. This is the case, even in a preperforated liner, whether cemented or not cemented. For this process to be most effective, the jet streams of the fracturing fluid from the BHA need to be focused directly into the jet-eroded perforation.

Beginning at the preselected fracture-placement location nearest the toe, perforations are jetted through the liner, and tunnels are jetted into the formation rock by high-pressure pumping of abrasive-laden fluid down the treating string and out the jets in the BHA. During this step, bottomhole (BH) and annulus pressure *below fracture-initiation* pressure levels must be maintained. After the pipe is penetrated and perforation tunnels have been created by the jetting action, the annulus is shut in at the surface or (more commonly) injection is initiated down the unsealed annulus to bring the system pressures up to near the pressure needed for fracture initiation (**Fig. 4**). Because of the Bernoulli effect[4-6] caused by the jetting action, the pressure inside the jetted cavities will be hundreds of psi higher than the wellbore pressure so that fracturing will only occur at that location along the lateral. Essentially, the jetted fluid will enter the growing hydraulic fracture, with some of the annulus fluid being sucked into it as the jetting action creates a jet-pump effect.

After fracturing is initiated, a conventional fracturing treatment (proppant-fracturing or acid-fracturing) is placed. If the liner is slotted or preperforated above the fracture location, an annulus injection rate is selected to provide sacrificial leakoff and allow all of the through-tubing fluid to be used for fracture extension and growth. All fracturing slurry or acid is pumped through the tubing string and jetted into the cavity connected to the fracture plane. Often, each fracturing stage is designed as though the operator were fracture stimulating a single zone through a (hypothetical) vertical wellbore drilled at that (3-D) reservoir location.

This process provides two additional benefits. First, for most treating conditions, injection down the annulus encounters very little fluid friction loss and the annulus essentially is a *live annulus*. This live annulus provides accurate and instantaneous pressure read-out of the bottomhole pressure values relative to fracture growth, or real-time monitoring of the pressure in the annulus adjacent to the fracturing event. The second benefit of the process is that with large, nondamaged perforation tunnels to fracture through, there is no near-wellbore tortuosity. This removes the problem of excessive multiple fractures growing simultaneously, the typical horizontal openhole nemesis. In practice, the fracture initiation usually requires so little additional energy that no noticeable pressure spike is observed.

After a fracturing stage is completed and the wellbore is flushed of the fracturing treatment, a tubing valve or ball check-valve seals the tubing from downhole pressure. The BHA is then withdrawn to the next desired fracture location by wet-stripping the tubing joints or by pulling the CT (whichever applies). The jetting, fracture initiation, and fracture-extension stages are repeated (**Fig. 5**). Because the Bernoulli effect is again maintaining the highest system pressure in the jetted cavities feeding the new fracture system at the tool location, most of the fluid pumped through the tubing will be growing the new fracture plane, with only minimal fluid *backing up* into the wellbore. As fluid flows toward the toe (where earlier stages created hydraulic fractures), fluid-loss seepage into created fracture systems is small and mostly satisfied by annular fluid injection. Previous fractures are still *super-charged* from the fracturing operations and subsequently have more resistance to fluid loss than the virgin rock encountered by the newest hydraulic fracture at the tool location.

This process is repeated a number of times, typically within a single rig-up of pumping service equipment and usually with only one trip in the hole with the BHA. After completion of the last planned fracturing stage, the treating string is pulled out and the well is cleaned up for production. Many post-hydrajet-fracturing cleanup trips have washed back minimal amounts of wellbore fill. Curable resin-coated proppants have been used in numerous proppant-fracturing treatments, including the case history presented here.

For most fracture-stimulation projects, reservoir simulation modeling is the best tool for determining the desired number and sizes of fractures for maximized return on investment (ROI). Such is the case as well in horizontal completions. Unfortunately, most operators have limited reservoir descriptions and access to only the most simple simulation software. Simple simulators can be very misleading if accurate reservoir descriptions are not available, especially with even a small degree of layering or if natural fracture swarms are a primary controlling factor to productive capacity. Furthermore, permeability anisotropy is often unknown, except in a very broad perspective.

With extremely large-volume treatments with numerous fracturing stages, multiple days may be required to complete the various stages, as well as a round-trip for tool replacement if tool abrasion is excessive. However, even in these cases, the savings in cost using the new method can be significant compared to the costs incurred from conventional fracture-stimulation techniques. The new system is cost-effective because it can provide substantially more effective stimulation than the lower-cost methods available.

The authors acknowledge that in some cases, conventional lower-cost stimulation methods are adequate. The new hydrajet-fracturing process is designed for those wells that require more effective stimulation. However, many case studies with vertical well completions have proven that the *best* wells often bring the operator the greatest possible ROI when they are more effectively stimulated; therefore, the same should also be true for numerous horizontal completions.

CASE HISTORY: SCREEN-WRAPPED HORIZONTAL COMPLETION

In late 2002, an operator in northern Asia began a detailed review to determine the most effective completion scheme within the area. The most common type of completion is the vertical well, often drilled on extremely dense spacing. Attempting to improve production compared to cost of completion and production, the operator recently started a horizontal drilling program in the area. The results from many of these early horizontal completions were unsatisfactory because several of these wells seemed to show higher cost per unit of produced oil. Stimulation efforts generally proved to be ineffective or uneconomical, especially since all of the wells were completed openhole with a screen (wire-wrapped, preperforated liner). **Fig. 6** shows a simplified log description of the reservoir, showing the thin oil zone and the approximate location of the lateral section through the zone.

As the operator learned more about the new hydrajet-fracturing process, a renewed interest was generated to evaluate horizontal completions further. Reviewing the existing horizontal wells, it was quickly found that treating those wells was not an option because their casing pressure rating averaged only about 1,750 psi; whereas, annulus treatment requirements (based on 8,000-ft well depths) exceeded 2,400 psig. These wells had been drilled to approximately 8,000 ft true vertical depth (TVD), with a horizontal length of approximately 1,000 ft within the pay interval. Typical measured depth was about 10,000 ft. Because of these conditions, to evaluate the new process, the operator had to use a new well that had the required strengths (pressure ratings) to apply a hydrajet-fracturing treatment.

As per the operator's customary means of completion, after cementing the vertical casing string, the lateral section was drilled with an 8.5-in. drill bit. A 5.75-in. casing with an ID of 5.15 in. was used for production casing. The casing section within the oil productive zone used preperforated joints with wire-wrapped screens on the outside of each joint. Because the wire-wrapped screens were not actually attached to the pipe, there was concern that jetting through the screens would cut too many of the wires and unravel them. Therefore, the operator decided to place a blank joint at each specific area where a fracture was to be placed.

During the planning stage of the treatment design, it was observed that the wellbore was drilled in close proximity to a water-bearing formation below, varying from 50 to 90 ft. It was therefore decided to limit the propped-fracture size to approximately 50 ft fracture height and less than 70 ft half-length and to position the fractures about 150 ft apart. Eight fractures were planned for the job, starting near the center of a blank joint at the toe.

As illustrated in **Fig. 7**, Fracture #7 was very close to the water zone, and extreme care would need to be taken to prevent the fracture from penetrating the water-bearing formation. Because fracture geometries generally cannot be guaranteed and accuracy in identifying the locations of water can also be questionable, the design plan incorporated relative permeability modifier (RPM) chemicals in the fracturing fluid for all stages to guard against excessive water production in the future. **Fig. 8** is a sketch to illustrate the general makeup of the BHA used for this treatment.

In all of the fracturing stages pumped, a near-screenout was induced at the end of the planned stage by dropping the annulus rate (and therefore, annulus pressure) during the final proppant-laden stage. This procedure reduces the fracturing fluid rate while increasing the proppant concentration, which generally induces tip screenout. Each fracture stage was designed to use 20,000 lb of 16/20 ceramic proppant followed by 8,000 lb of resin-coated proppant *packed* in the near-wellbore portion of the fracture. Proppant was packed at the end of each fracturing treatment by decreasing the injection rate. To minimize the probability of fractures penetrating the water zone below, all of the jets were positioned to generally face upward. This positioning gave the initiating fracture a greater tendency to initiate upward before extending downward; thus, the position enabled maximization of the fracture size while minimizing the possibility of reaching the water zone. The designers also decided to make the last fracture (#8) almost twice as large because it was positioned significantly up the bend in the heel and much further above the water zone, almost out the top of the oil zone itself.

The stimulation treatments were all executed very closely to the job design, except for Stage 7. While positioning the tool for Stage 7, there was a problem with the tubing anchor tool (up hole of the BHA). Because the operator was originally concerned that this fracture location was the one most likely to fracture down into the lower water zone, this perforating/fracturing stage was omitted. The tool assembly was pulled back to the scheduled location for fracturing Stage 8, which was much higher on the structure. The final stage was pumped as scheduled for Stage 8 with no problems observed during the treatment.

After post-fracturing wellbore cleanup operations, the well was placed on production. Initially, production of this well showed very promising results. A production rate approximately twice that expected by the operator from the stimulation treatment was achieved, and the oil production continued to increase for several weeks. Eventually, the well began to produce excessive gas and production had to be choked back. Because it is not marketable from this field, gas has to be flared (a hindrance to oil production). It was later deduced that the larger fracture placed with Stage 8, which was also highest on structure, might have penetrated an overlaying gas cap, a situation not addressed or considered before the job. Although a high gas-oil ratio (GOR) limits the oil-producing potential of this well, the treatment results clearly demonstrate that the hydrajet-fracturing process is a very effective stimulation technique for horizontal completions in this reservoir (even when used with a screen-wrapped, pre-perforated liner). After more than six months, the well is still producing at much higher rates than were possible before the stimulation treatment. As of this writing, the operator is drilling the second well for further evaluation of this process during the fourth quarter of 2003.

OTHER HYDRAJET FRACTURING APPLICATIONS IN NON-CEMENTED LINER/HORIZONTAL WELLS

There have been several other successful applications of the hydrajet fracturing process in horizontal wells completed with non-cemented liners. Currently, data on most of these field examples are not yet being released by the operator. Some are planned for future technical papers to be presented later in 2004, and some operators are considering whether they should acquire additional lease positions before releasing treatment data results. In addition to its success in bare openhole laterals, the hydrajet-fracturing process has been very successful in liner applications.

CONCLUSIONS

The results of this case study provide the following conclusions.

- Many horizontal wells need hydraulic-fracturing stimulation
- Many wells with non-cemented liners are not effectively stimulated using conventional techniques
- Fluid distribution techniques, such as limited-entry perforating, often fail to control the problem of excessive multiple fractures and seldom result in stimulation of the entire lateral
- The hydrajet-fracturing technology has been very successful in bare openhole completions
- Early successes with the hydrajet-fracturing process in non-cemented liner completions indicates that it is a very promising stimulation method for these wells

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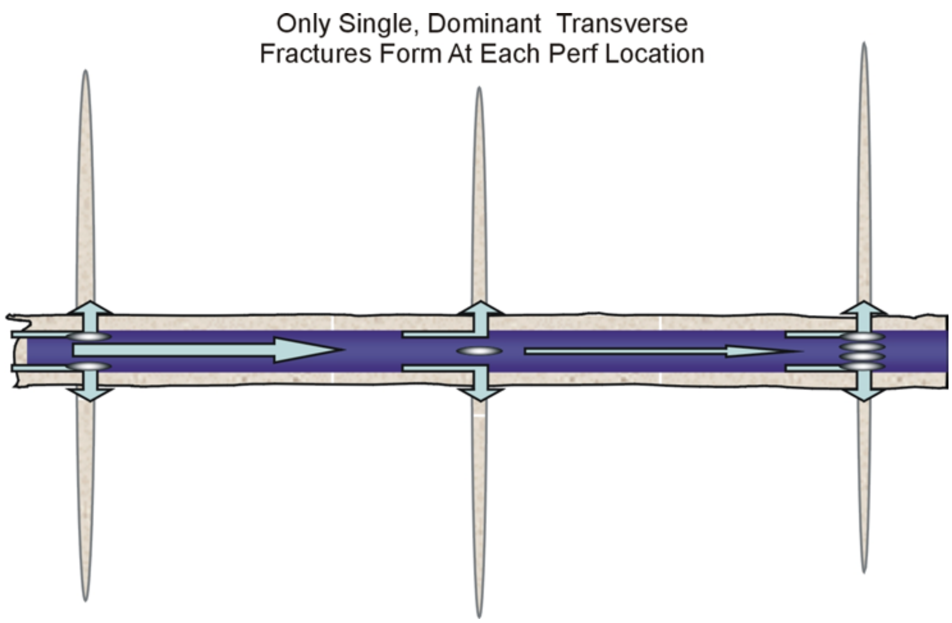

Figure 1 — High-rate, Limited Entry Fracturing of a Non-cemented Liner, Ideal Result

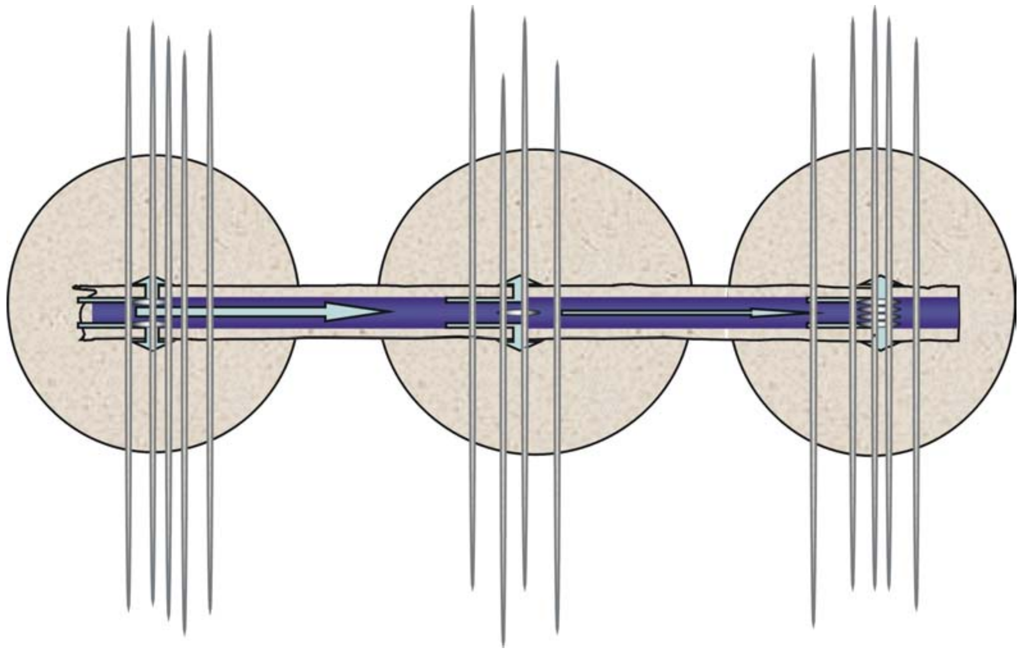

Figure 2 — High-rate, Limited Entry Fracturing of a Non-cemented Liner, Realistic Result

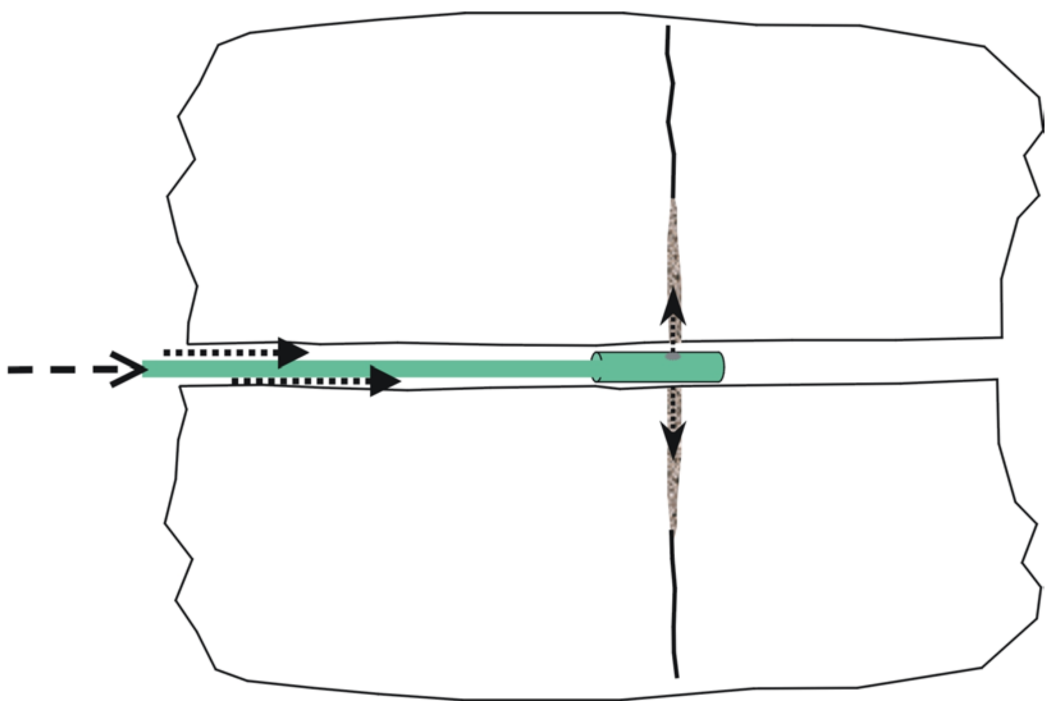

Figure 3 — First Stage of a Hydrajet-Fracturing Treatment with BHA Positioned at First Desired Fracture Location (Nearest To Heel)

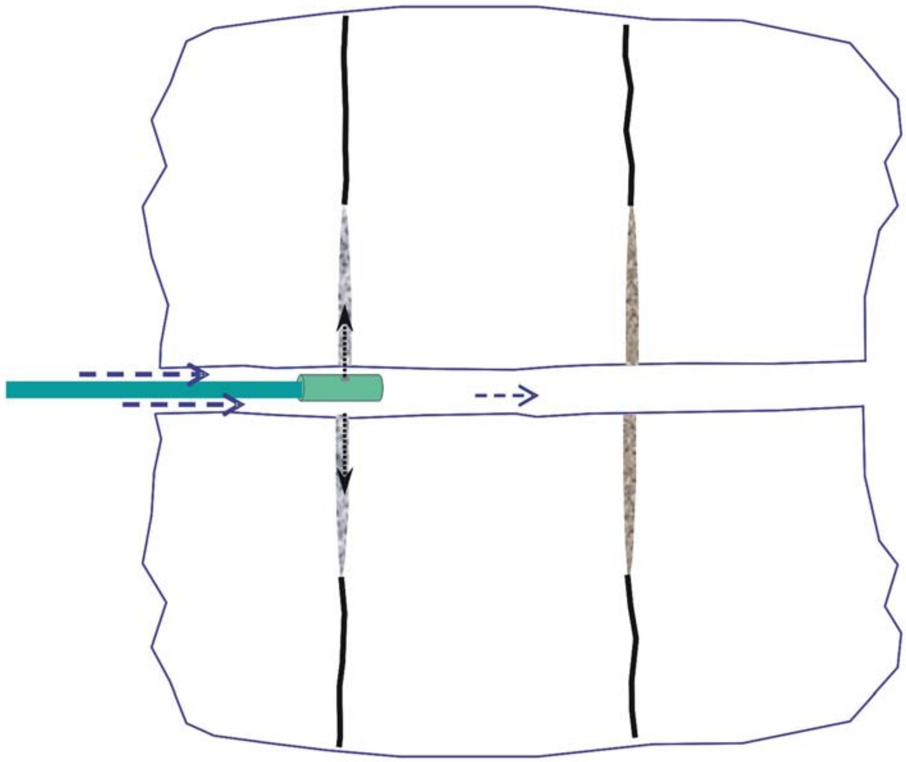

Figure 4 — Second Fracturing Stage, After BHA Pulled Back to Position for Second Planned Fracture Location

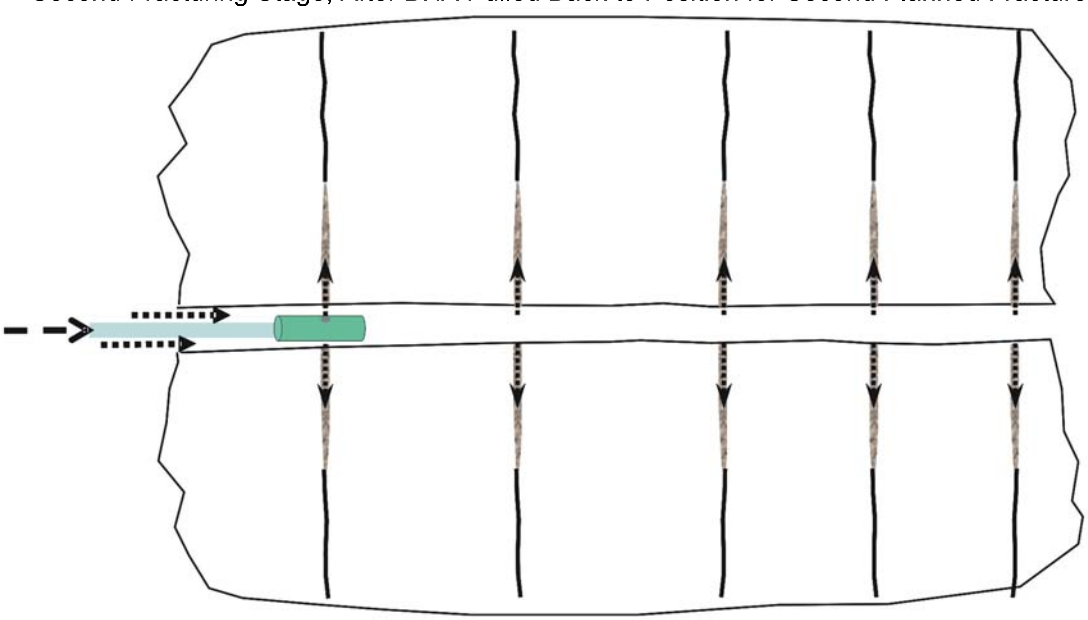

Fig. 5 — The process of Fig. 4 is repeated until fractures have been placed at all planned locations along the lateral.

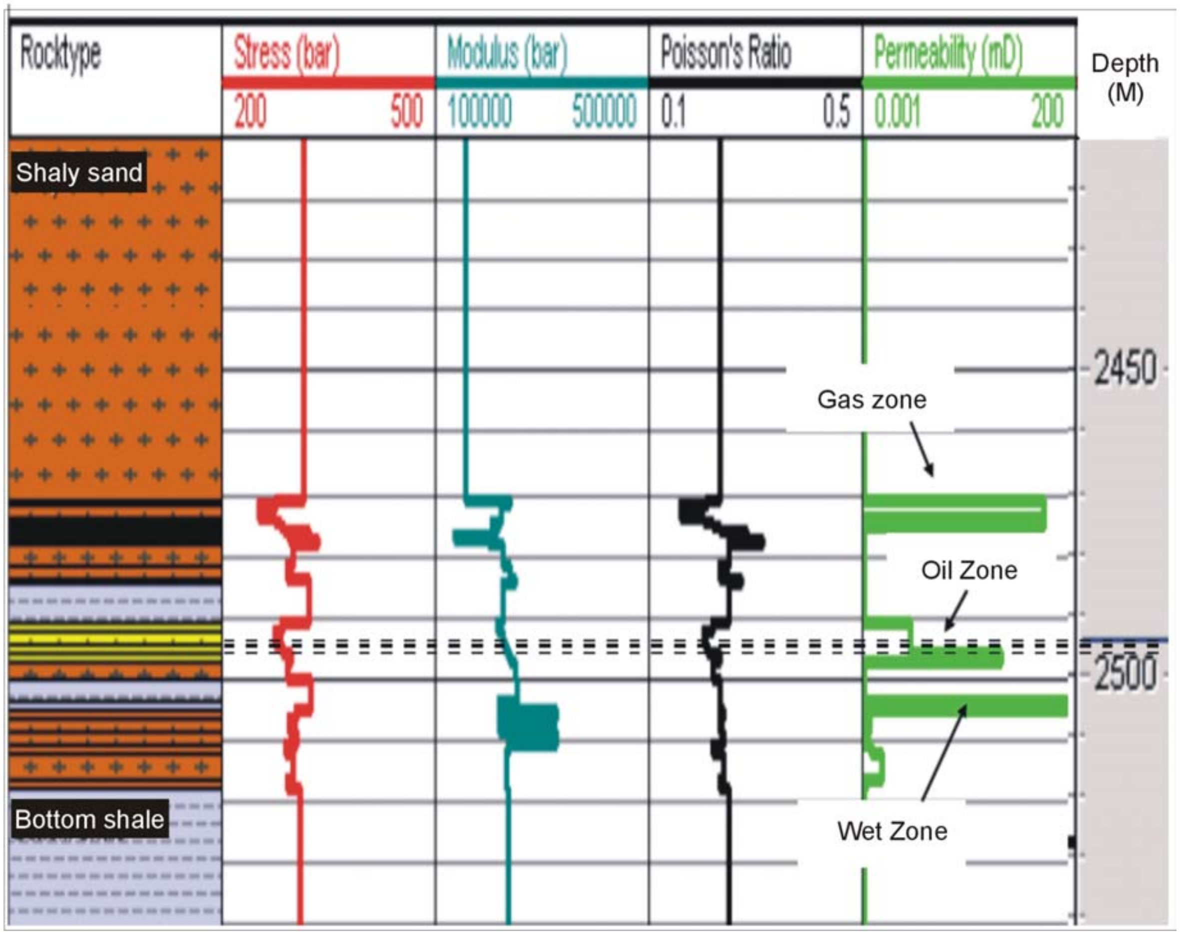

Figure 6—Reservoir Rock Properties (double dashed lines approximate the horizontal wellbore location.)

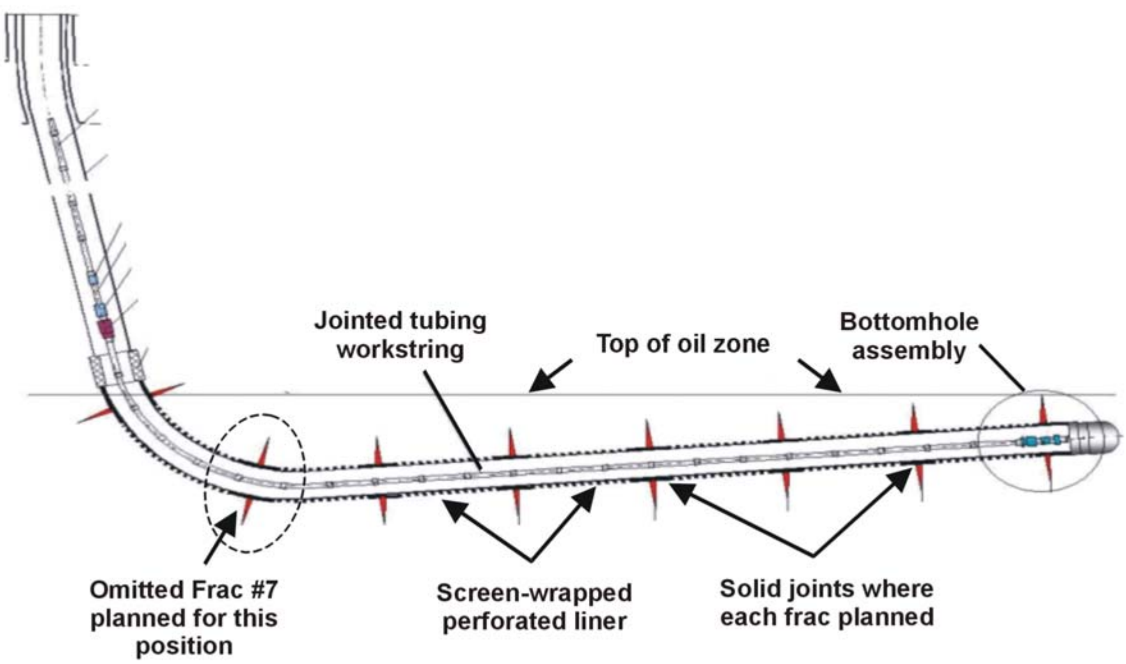

Figure 7 — Illustration of the Eight Fracture Stages Planned

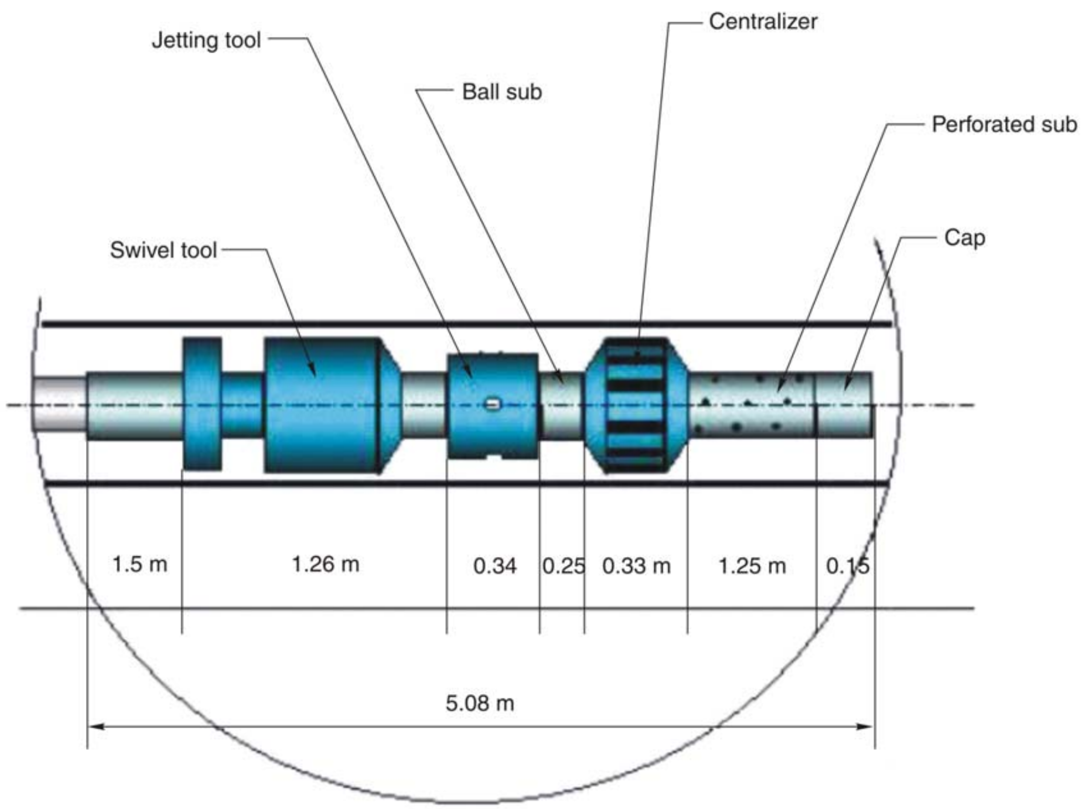

Figure 8 — Sketch Showing the Makeup of the BHA Used