COMPLETION PRACTICES ADDRESSING ZONAL ISOLATION AND PERFORATION DESIGN FOR LIMITED-ENTRY FRACTURING OF HORIZONTAL WELLS

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ABSTRACT

Drilling and completing long, horizontal sections in low to moderate permeability reservoirs has become commonplace in many oil and gas producing regions of the world. Economically successful exploitation of these types of reservoirs usually requires hydraulic fracture stimulation, in both vertical and horizontal completions.

Many completion techniques have been used for fracture stimulation of horizontal wells. Multiple stage fracturing treatments are highly effective, but the high cost and risk associated with this type of completion often make it unattractive. Limited-entry fracturing has proved to be an effective stimulation method for horizontal wells with an acceptable level of cost and risk.

Successful limited-entry fracturing of horizontal wells is highly dependent on effective zonal isolation and perforation design. This paper presents a case history of horizontal completions using limited-entry fracture stimulation. Zonal isolation methods, perforating strategies, and their affects on limited-entry fracturing success are discussed and compared.

INTRODUCTION

Exploration for oil and gas is more challenging now than ever before. Low-permeability reservoirs that were once regarded as marginal or uneconomic are now major plays in many areas. Horizontal wellbores are often the most cost effective method of drilling and producing these low-permeability reservoirs. Early on when horizontal drilling was first used in low-permeability reservoirs, it was thought that a horizontal well would produce at economical rates with little or no stimulation. Now it is generally accepted that significant stimulation is most often required for a low-permeability horizontal completion to achieve economical producing rates.

A wide range of completion methods have been used on horizontal wells, each with varying degrees of risk and success. Some methods have been mechanically successful with acceptable production rates, but high completion costs rendered them economically unsuccessful. Some methods with acceptable costs have failed to achieve economical production rates. Limited-entry fracturing has proven to be an effective completion method for horizontal wells, providing economic success with an acceptable level of risk.

Successful limited-entry fracturing on horizontal wells requires that each perforated interval along the lateral is effectively stimulated. Perforations can be designed to control the treatment fluid distribution as it exits the wellbore, but without some form of annular isolation, the formation will not necessarily be stimulated at the perforated intervals. Effective zonal isolation is a critical component of a limited-entry fracturing completion. **Figures 1 and 2** illustrate the results of no zonal isolation and effective zonal isolation on limited-entry fracturing treatments.

LIMITED-ENTRY FRACTURING

The concept of limited-entry fracturing is using perforation friction pressure to control the stimulation fluid distribution into each perforated interval. This technique has been used successfully for years in vertical well completions. Several aspects of limited-entry fracturing in horizontal wells are worthy of attention: (1) fluid friction along the tubulars in long intervals, (2) little or no hydrostatic pressure changes along the lateral, and (3) perforation erosion by proppant slurries.[1] The beneficial affect of hydrostatic pressure that helps to offset pipe friction in vertical wells does not exist in horizontal wells. Pipe friction in very long horizontal completions is often the limiting factor when determining the maximum treating rate. Perforation erosion, which only has a minor effect on fluid distribution in vertical wells, can significantly affect the fluid distribution in horizontal stimulation treatments. Because the pressure differential across the perforations is highest in the heel section and decreases to the lowest in the toe section, and because the heel perforations are the first to encounter the sand slurries, the erosional effects of sand slurries will de-burr and enlarge the perforations in the heel section of the wellbore much more than in the toe section. Consequently, more of the fracturing treatment will be placed in the heel section and less in the toe section. Arbitrary allowances can be made for erosional effects by reducing the number of perforations in the heel section and/or increasing the number of perforations in the toe section.

Other factors that affect the success of limited-entry fracturing in horizontal wells are tortuosity or near-wellbore friction (NWF) and stress variances along the lateral. Stress variances and NWF of several hundred psi are not uncommon, and can dramatically affect the fluid distribution during the fracturing treatment. Spreadsheets have been developed for limited-entry perforation design in horizontal wells that include calculations addressing pipe friction, perforation friction and coefficients, vertical depth variations, and stress differences along the lateral. Tortuosity (NWF) effects are not so easily addressed, because their magnitude and location along the lateral are unknown. Completion practices can be implemented to help reduce or minimize tortuosity effects, improving the success of limited-entry fracturing of horizontal wells.

ZONAL ISOLATION METHODS

One of the primary concerns in limited-entry fracturing of horizontal wells is adequate zonal isolation. To effectively control fracture placement at specific intervals along the lateral, some type of annular zonal isolation or diversion must be employed. Openhole external casing packers, gel plugs or chemical packers, and cements have all been used with varying degrees of success. Openhole, pre-perforated liner completions have been used as a low-cost alternative, but have had limited success at effectively fracture stimulating horizontal wells.[6]

Cement has proven to be a consistent and reliable method for controlling fracture placement at specific intervals along the wellbore.[3] However, conventional cements can have a negative impact the completion. Because conventional cements have a low solubility in acid, perforations can be difficult to break down, and can inhibit fracture initiation and cause excess tortuosity during stimulation and production. Successful horizontal limited-entry stimulation requires that all perforations be open and in communication with the formation, and that the designed perforation friction controls the fluid distribution along the wellbore. Un-opened perforations and NWF resulting from tortuosity caused by the conventional cement can significantly alter the fluid distribution and adversely impact stimulation effectiveness. Conventional high-compressive strength cements with a typical acid solubility of less than 5% cannot be reliably removed so that each perforation is openly communicating with the formation. Isolating each set of perforations using retrievable tools and balling out the perforations with perf-pack ball sealers is the most reliable method to ensure all perforations are broken down. This process increases completion time and increases both risk and cost.

A non-standard, acid-soluble cement (ASC) has been used for providing zonal isolation without impeding stimulation and production.[2-3] This type of cement has a fast solubility rate and is highly soluble (>90%) in acid-based stimulation fluids. ASC has physical properties much like conventional cement (Table 1). It can be specifically formulated to provide the proper weight, fluid-loss, free water, compressive strengths, and pump times required for particular well conditions. Slurry densities and yield ratios can range from 13.0 lb/gal to 15.8 lb/gal and 3.55 cf/sk to 2.00 cf/sk respectively. ASC can also be foamed if lower-density slurries are needed. The cost of ASC per cubic foot of slurry is comparable to that of conventional cements with similar properties.

The easy removal of ASC material from around the perforation cluster makes it especially suitable for limited-entry horizontal applications. The high-solubility properties allow for the development of an enlarged area of communication in the annulus immediately adjacent to the perforations while still providing excellent zonal isolation along the wellbore. This pocket that is dissolved around the casing at the clustered perforation point eliminates the tortuosity and fracture-entry pressure effects that could alter the planned limited-entry fluid distribution. Also, during production, the skin effects, reduced near-wellbore conductivity, and perforation plugging problems associated with conventional cements are eliminated.

PERFORATING PRACTICES

Perforating for hydraulic fracturing is different from perforating for production, and perforating for hydraulic fracturing in horizontal wells varies from vertical wells also. There are many variables to consider, including gun size, perforation phasing, shot density, charge type (entry hole and penetration), perforated interval length, pressure conditions and fracture/wellbore orientation.

Perforated interval length can significantly affect hydraulic fracturing success in both transverse and longitudinal oriented laterals. A perforated interval that is too long can result in multiple fractures in the near-wellbore area.[5]

Multiple fractures can increase bottomhole treating pressures and near wellbore friction (NWF), and decrease fracture width and fluid efficiency. These conditions that result from multiple fractures can hinder proppant placement and stimulation efficiency. Point-source perforating (PSP) has greatly improved the success of hydraulic fracturing of horizontal wells.[1,3] Limiting the perforated interval length of each perforation cluster to 4 wellbore diameters or less (usually 1 to 3 ft) has shown to be an effective method of reducing or eliminating multiple near-wellbore fractures. Fracture width development at the perforation cluster is increased, improving proppant placement.

A wide range of perforation charges are available, each with a specific depth of penetration and entry-hole diameter (EHD). When perforating for hydraulic fracturing, deep penetration into the formation is not required, as it has been observed in studies that the fracture initiation point is at the cement/formation interface and not along the perforation tunnel.[4] The hole size or EHD that is chosen for limited-entry fracturing will affect the total number of holes in the wellbore and the number of holes that can be placed at each perforation cluster. With smaller hole sizes, more perforations can be used and the designed fluid distribution can be matched closely to the desired fluid distribution. However, the erosional effects and hole enlargement causes by proppant slurries are much greater with small diameter perforations than with larger diameter perforations. In a horizontal well, hole enlargement affects the perforations nearest the heel first and more significantly than the perforations farther down the lateral, and can result in a fluid distribution skewed towards the heel section and ineffective stimulation of the rest of the lateral. When using larger perforation diameters for limited-entry fracturing, hole enlargement and erosional effects of proppant slurries are lessened, and changes in the fluid distribution are minimized allowing for effective stimulation of the entire lateral.

Perforation phasing also affects the fracturing process. Orienting perforations in the direction of the fracture plane can minimize near-wellbore tortuosity and improve proppant placement.[1] However, the preferred fracture direction is not always known, and the costs associated with determining fracture orientation and running oriented perforating guns in a horizontal well may be unattractive. Studies have shown that if the perforations are within 30° of the preferred fracture direction, near-wellbore tortuosity can be minimized, so a perforation phasing of 60° or less is preferred.[5]

CASE HISTORY

Project Background. The case history focuses on horizontal wells drilled in a 3,550-acre, unitized field located in southeastern Lea County, New Mexico (Figure 3). Initial field development began in 1992 when the first vertical wells were completed in the Third Bone Spring Sand formation. In 2000, there were 39 active vertical oil producers in the unit, and the first horizontal well was drilled. As the project continues, 22 horizontal wells have been drilled within the unit, with lateral lengths ranging from 1,200 to 6,500 ft at an average total vertical depth of 12,260 ft. Table 2 gives typical horizontal well and reservoir descriptions. A pressure maintenance project was initiated on the unit in 2000, and some of the horizontals have been converted to injection wells, but most are producers. Figure 4 shows a schematic of a typical horizontal wellbore.

Well Planning and Drilling Considerations. Before drilling the first horizontal well, fracture orientation in the pay interval was investigated using imaging and acoustic log information from vertical wells. An exact fracture azimuth was not evident, but the general fracture orientation was determined to be northeast-southwest. The laterals were drilled with an azimuth of 70° east of north, which was believed to be nearly parallel to the fracture orientation. This direction was chosen because it would accommodate the existing vertical wells and would also be suitable for the pressure maintenance project.

Vertical pilot holes were drilled on some of the wells, and openhole log information was used to determine the target interval thickness, reservoir quality, and vertical depth. A well trajectory was then defined using this data and offset well information. As the lateral was drilled, mud logging was used to gather geological information about the reservoir. This information would be used later in the perforating and stimulation design process. Openhole logs were not run in the laterals due to the added risk and cost, and also because of the available information from the offset wells.

Zonal Isolation Methods. Almost all of the horizontal liners in the field were cemented. Two of the wells were not cemented due to hole conditions and liner equipment problems. At the beginning of the horizontal project, liners were cemented with ASC. After several wells had been drilled and completed, cementing procedures were changed, and conventional cement was used. Later, after experiencing difficulties during frac treatments on some of the conventionally cemented wells, the cement type was changed back to ASC. As a result, about one-half of the wells were cemented with conventional cement and one-half with ASC.

The job procedure for cementing the liners in place was essentially the same regardless of the type of cement used. Cements were batch-mixed and densities measured with pressurized mud scales before pumping downhole. The cement was preceded with a weighted spacer to aid in mud displacement and hole cleaning. The spacer was designed to be compatible with both the cement and the mud. Pump rates on both conventional cement jobs and ASC jobs were similar (typically 5 bbl/min). Slurry volumes were calculated to circulate cement to the liner top plus another 200 ft above. After the cement was displaced and the liner wiper plug was landed, the liner hanger packer was set and any excess cement was circulated out.

It was generally assumed that the liner had been successfully cemented if no unusual events occurred during the cement job and cement was circulated off the liner top after the liner hanger packer was set. Cement bond logs were not run due to the risk, tool availability, and additional completion time required.

COMPLETION METHODS

The completion procedures for the conventional cement and ASC wells were similar. First, a liner clean out trip was made and the liner, casing, and tubing were pickled with xylene and hydrochloric acid. Acetic acid was spotted in the lateral, and several sets of tubing-conveyed perforating guns (TCP) were picked up and run in the lateral in one trip Pumping equipment was used to activate the pressure actuated TCP guns, perforating the liner at multiple points along the horizontal section of the wellbore, and the perforations were broken down by pumping away the spot acid. The TCP guns were removed and frac equipment was rigged up, and the hydraulic fracturing treatment was pumped down the casing and liner.

PERFORATION AND FRAC DESIGN

The limited-entry fracture design process addressed many aspects, such as lateral length, pay thickness and pay quality along the lateral, fracture gradients, reservoir pressures, and wellbore tubulars. The number of perforation clusters or fractures that could be placed along the lateral was affected by the length of the lateral and the wellbore configuration. Information from previous fracturing treatment and 3-D fracture models indicated that a minimum rate of about 10 bpm or greater was required to effectively fracture stimulate a perforation cluster. Wellhead treating pressures were limited to the pressure rating of the casing less a safety factor. A maximum surface treating rate was calculated using anticipated bottom hole treating pressures, friction pressures, and maximum wellhead pressure limitations. This maximum surface rate was used to determine the number of perforation clusters that could be placed along the lateral and effectively fracture stimulated.

Mud log data such as drill rates, drill cuttings descriptions, and hydrocarbon shows were used to evaluate pay quality along the horizontal borehole, and information from log cross-sections of offset vertical wells and from a 3-D reservoir model was used to estimate pay thickness. Perforation cluster points were spaced out as evenly as possible along the horizontal, while trying to keep them in the thickest and best quality pay. Shaley areas identified on the mud log and very thin pay sections were avoided when choosing perforation cluster locations.

After the perforation cluster locations were determined, a 3-D fracture model was used to design the fracture treatment for each perforation cluster. Because the horizontal wellbores were believed to be aligned with the preferred fracture plane, and perforation clusters spacing was typically about 400 ft, individual fractures were design to have a propped wing length of about 175 ft. This design would result in a series of nearly-connecting longitudinal fractures along the length of the lateral. Fluid and proppant volumes for each fracture were combined into a single, high rate, limited-entry treatment schedule. A typical treatment schedule, including proppant and fluid details, is described in Table 3.

Perforation design for both conventional cement and ASC wells used the same spreadsheet calculations. Information input into the spreadsheet, including perforation cluster location, perforation density, treatment rate into each cluster, and minimum perforation friction was used in calculating the number of holes needed at each cluster location for the desired rate distribution. The designed rate into the first two or three perforation clusters nearest the heel was reduced slightly on the spreadsheet calculations to compensate for the increase in rate that would occur as a result of the erosional effects and hole enlargement caused by the proppant slurry. Table 4 illustrates the final spreadsheet output of a typical well, and Figure 5 gives a graphical description of the designed rate distribution.

Perforation gun sizes, charge types, entry-hole diameters, and phasing were the same for all wells of like liner sizes throughout the project. The point-source perforating (PSP) technique was used in order to reduce or eliminate multiple fractures and allow maximum fracture width development at the perforation cluster. Perforations shot density and phasing was 6 shots per foot and 60 degrees when there were six or more holes in a cluster. For clusters having four or fewer holes, shot density and phasing was 3 shots per foot and 120 degrees. This practice limited the perforated interval length to 1.5 ft or less and insured at least 360 degrees of radial coverage at the cluster.

PERFORATING AND BREAKDOWN PROCESS

The process used to shoot and break down the perforation clusters on conventional cement liners differed from that used on ASC liners. On a typical ASC liner, 6,000 to 8,000 gallons of 10% acetic acid would be spotted in the wellbore. Pressure-actuated TCP perforating guns with time-delay firing heads were run in the lateral. The firing heads were pinned to fire sequentially from the deepest perforation cluster to the shallowest (toe to heel). This sequential firing order and the time-delay firing heads allowed a significant volume of acid to be pumped through the toe perforation cluster before the next set of guns fired. To help ensure that all perforations were broken down, pump rates and pressures exceeding fracture initiation pressure were maintained during the perforating process until all of the guns had fired and the 10% acetic acid was displace from the liner. The volume of acetic acid used in the perforation breakdown should have been sufficient to dissolve a small pocket of ASC in the annular space immediately adjacent to each perforation cluster. On wells with ASC, a 12,000 to 16,000- gal stage of 7-½ % HCl was pumped immediately ahead of the main fracturing treatment to further clean up the perforation clusters. This fluid was pumped at the designed limited-entry fracturing rate to increase the pressure differential across the perforations, helping to ensure that all perforations were accepting acid, and the ASC material behind the perforations was being removed.

Wells cemented with conventional cement were also perforated using pressure-actuated TCP guns with time-delay firing heads. Smaller acid volumes (typically 1000 gallons) were spotted in the wellbore and pumped away during the perforating process due to the low acid solubility of conventional cement. The firing order of the TCP assembly was set up to fire the toe gun first and allow most of the spot acid to be pumped through this set of perforations before the remainder of the guns fired. This was to help ensure that the deepest perforation cluster was broken down and accepting fluid. Pump rates and pressures in excess of fracture initiation pressure were maintained until all of the guns had fired and the acid was displaced from the liner. Further breakdown and cleanup of the perforations was attempted with an acid ball-out job. This treatment was usually performed with the frac equipment the day before the main frac job. A typical acid ball-out treatment consisted of 12,000 gal of 15% hydrochloric acid pumped at 10 to 20 bbl/min. Biodegradable perforation ball sealers were injected throughout the acid stage for diversion, and the acid was displaced from the wellbore with treated water.

FRACTURING TREATMENTS

Fracturing treatments on the horizontal wells were essentially the same whether they were cemented using ASC or conventional cements. With the exception of the acid spearhead for ASC wells and the acid ball-out for conventional cement wells, fluids for all fracturing treatments consisted of slick water and low polymer delayed crosslinked borate gels. Several proppant types were used throughout the project, ranging from resin coated intermediate strength ceramics to light-weight ceramics with mesh sizes ranging from 20/40 to 16/20 mesh. Most of the wells were treated with 18/40 intermediate-strength, ceramic proppant. All of the wells were treated down the casing and liner with designed rates ranging from 60 to 120 bbl/min. A typical treatment schedule is illustrated in Table 3.

OBSERVATIONS

At the beginning of the horizontal drilling project, liners were cemented using ASC. Fracture treatments were pumped to completion, with rates and pressures close to those predicted by the design (Figure 6). After several wells had been drilled and completed, liner cementing practices were changed and conventional cement was used. Fracture treatments on the conventionally cemented wells were not often pumped as designed and pumping schedules were frequently changed during the job to adjust for the lower rates and higher pressures that were encountered (Figure 7).

After reviewing the fracture treatment job data from the completed wells, it was noted that wells with conventional cement always had significantly higher observed bottomhole treating pressures than predicted (Figure 8). Observed bottomhole treating pressures on ASC wells were usually within 300 psi of the predicted pressures. These bottomhole treating pressures were all calculated with the same method, using the actual frac gradients and wellbore friction to the first perforation cluster on each well.

The difference between the observed bottomhole treating pressures and the predicted bottom hole treating pressures was defined as entry-friction. This entry-friction was on average 1,250 psi for conventional cement wells and less than 300 psi on ASC wells (Figure 9). The high entry-friction on the conventional cement wells was attributed to near-wellbore friction caused by excess tortuosity and perforation friction from holes that were not accepting fluid.

Proppant slugs were pumped during the pad in all of the treatments. The proppant slugs were used to reduce tortuosity effects and multiple fractures. Upon reviewing the fracture treatment data, it was noted that the proppant slugs had little affect on ASC wells, but significant affects on conventional cement wells. This indicated that tortuosity and multiple fractures were much more prevalent in conventional cement wells.

Although both types of wells were perforated using the point-source perforating technique and perforations were broken down and acidized, the ASC wells treated much closer to predicted (designed) pressures. The unique properties of the ASC material allowed it to be dissolved from the annulus at the perforation cluster, reducing or eliminating tortuosity and helping insure that each perforation was open and in direct communication with the formation.

CONCLUSIONS

- Limited-entry fracturing can be used to effectively stimulate horizontal wells. The success of limited-entry fracturing treatments can be affected by the zonal isolation and perforating methods used in the completion.
- The point-source perforating (PSP) technique has been used to improve limited-entry fracturing success on horizontal wells. However, point-source perforating by itself does not necessarily eliminate entry-friction resulting from tortuosity and unopened perforations.
- Horizontal wells with ASC had significantly less entry-friction and treated much closer to predicted pressures than conventional cement wells. ASC can improve fracture effectiveness by reducing tortuosity effect and unopened perforations that disrupt the planned fluid distribution of limited-entry fracturing treatments.

As a result of this study, cementing procedures for horizontal wells drilled in the unit have utilized ASC. This method of zonal isolation is now used on the majority of the operator's wells that are stimulated using limited-entry fracturing.

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NOMENCLATURE
ASC = Acid soluble cement
BHTP = Bottomhole treating pressure
EHD = Entry hole diameter
HCl = Hydrochloric acid
PBHTP = Predicted bottomhole treating pressure
NWF = Near-wellbore friction
PSP = Point-source perforating
TCP = Tubing-conveyed perforating

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Table 1
Properties of Acid Soluble Cement (ASC) and Conventional Cement

Property	Acid Soluble Cement (ASC)	Conventional Cement
Slurry density	14.9 lb/gal	16.2 lb/gal
Slurry yield	2.45 ft^3/sk	1.18 ft^3/sk
Free water	0.00%	0.00%
Fluid loss	130 cc/30 min	100 cc/30 min.
Pump time	4 hrs. 30 min	4 hrs. 30 min.
Compressive strength (12 hr)	400	1,400
Compressive strength (72 hr)	1,100	3,200

Table 2
Typical Well and Reservoir Properties

Vertical section	7-in., 26-lb casing from surface to approx. 12,260 ft TVD
Horizontal section	6.125-in. hole; 4.5-in., 11.6-lb liner for 2,500 to 6,500 ft
Formation	Third bone spring sand
Formation top TVD	12,200 to 12, 300 ft
Average gross interval	130 to 230 ft
Average net pay	30 to 80 ft
Average pay porosity	13.50%
Average pay permeability	0.1 to 1.0 md
Pay zone lithology	Fine-grain sandstone

Table 3
Treatment Schedule for Typical Limited-Entry Horizontal Frac

Stage	Fluid Volume (gal)	Fluid Type	Proppant Concentration (lb/gal)	Proppant Type
1 - Pre-pad	8,000	Slick water		
2 - Pad	24,000	Delayed XL borate		
3 - Sand Slug	3,000	Delayed XL borate	0.5	18/40 ISP
4 - Pad	25,000	Delayed XL borate		
5 - Sand Slug	3,000	Delayed XL borate	1.5	18/40 ISP
6 - Pad	26,000	Delayed XL borate		
7 - Proppant slurry	4,000	Delayed XL borate	0.5	18/40 ISP
8 - Proppant slurry	6,000	Delayed XL borate	1	18/40 ISP
9 - Proppant slurry	8,000	Delayed XL borate	1.5	18/40 ISP
10 - Proppant slurry	10,000	Delayed XL borate	2	18/40 ISP
11 - Proppant slurry	18,000	Delayed XL borate	2.5	18/40 ISP
12 - Proppant slurry	38,000	Delayed XL borate	3	18/40 ISP
13 - Proppant slurry	30,000	Delayed XL borate	3.5	18/40 ISP
14 - Proppant slurry	10,000	Delayed XL borate	4	18/40 ISP
15 - Flush	19,200	Slick water		

Table 4
Sample Data from Part of Limited-Entry Perforation Design Spreadsheet

Perf Cluster	MD (ft)	Distance from Heel Cluster (ft)	Wellbore Rate at Cluster Rate	Injection Rate into Cluster (bpm)	% of Total Rate	No. of Holes	Perf Phasing (deg.)	Shot Density (spf)
1	12XXX	0	105.98	7.58	7.15%	2	120	3
2	13XXX	340	98.4	10.47	9.88%	3	120	3
3	13XXX	680	87.93	9.64	9.10%	3	120	3
4	13XXX	1020	78.29	8.88	8.38%	3	120	3
5	14XXX	1360	69.42	10.92	10.30%	4	120	3
6	14XXX	1700	58.5	10.15	9.58%	4	120	3
7	15XXX	2430	48.35	10.96	10.34%	5	60	6
8	15XXX	2830	37.39	12.29	11.60%	6	60	6
9	15XXX	3230	25.09	11.76	11.09%	6	60	6
10	16XXX	3630	13.34	13.34	12.58%	7	60	6

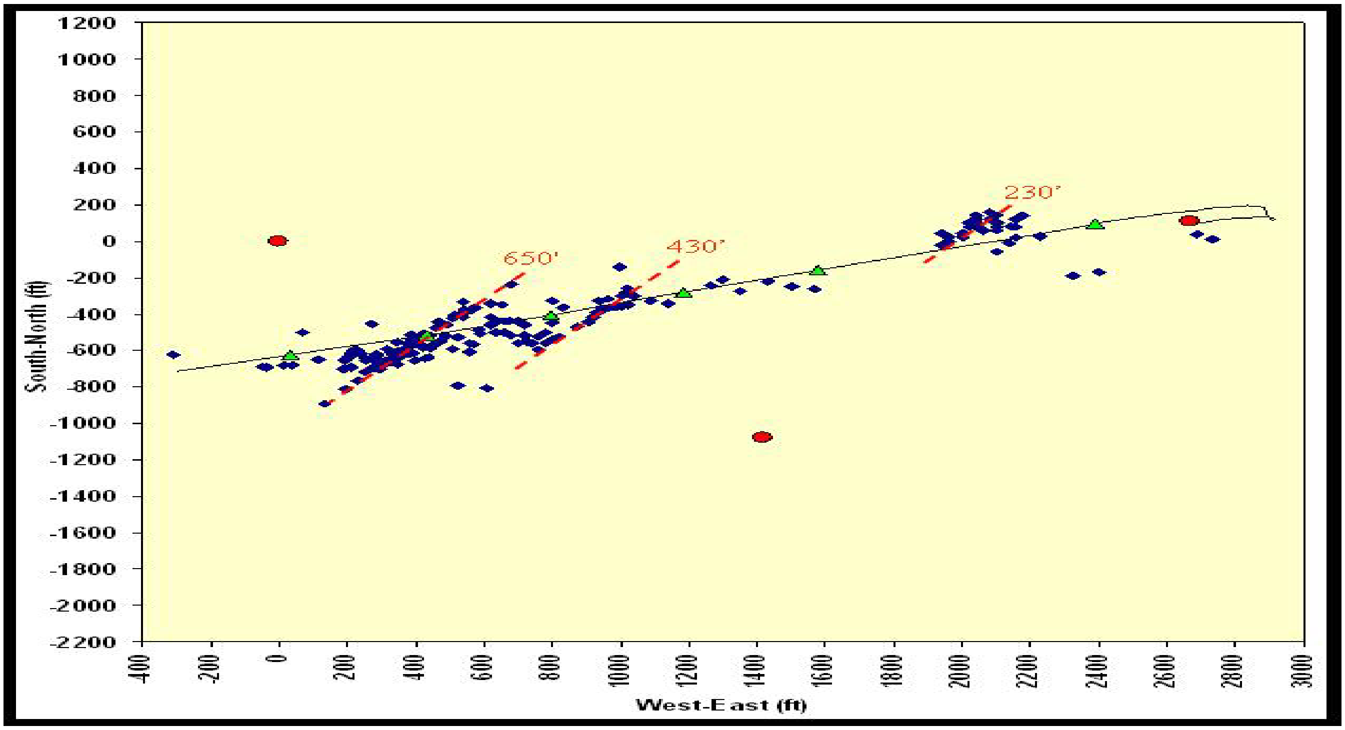

Figure 1 – Microsiesmic Fracturing Mapping of a Limited-Entry Fracturing Treatment on an Un-cemented Horizontal Well. Although there were eight perforation clusters designed for limited-entry, only three fractures were generated along the wellbore.

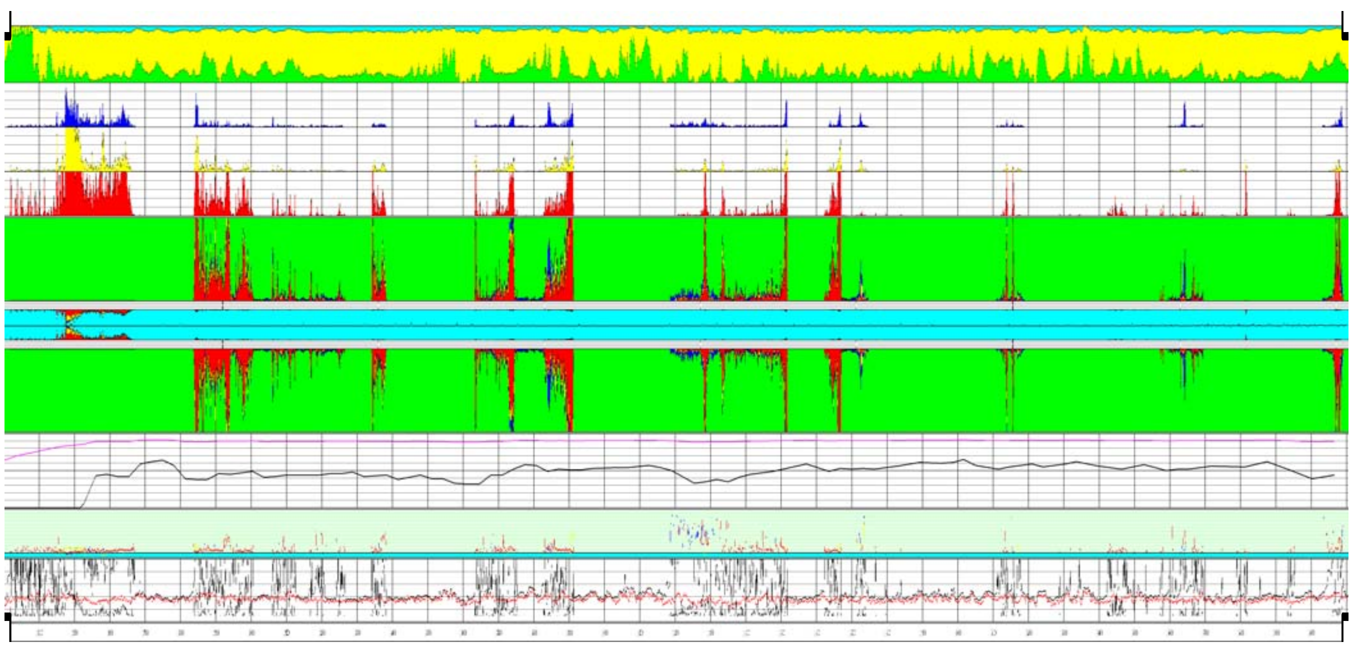

Figure 2 – After-frac Tracer Log From a Limited-entry Fracturing Treatment on an ASC Horizontal Well The log indicates that propped fractures were created at all eight perforation clusters.

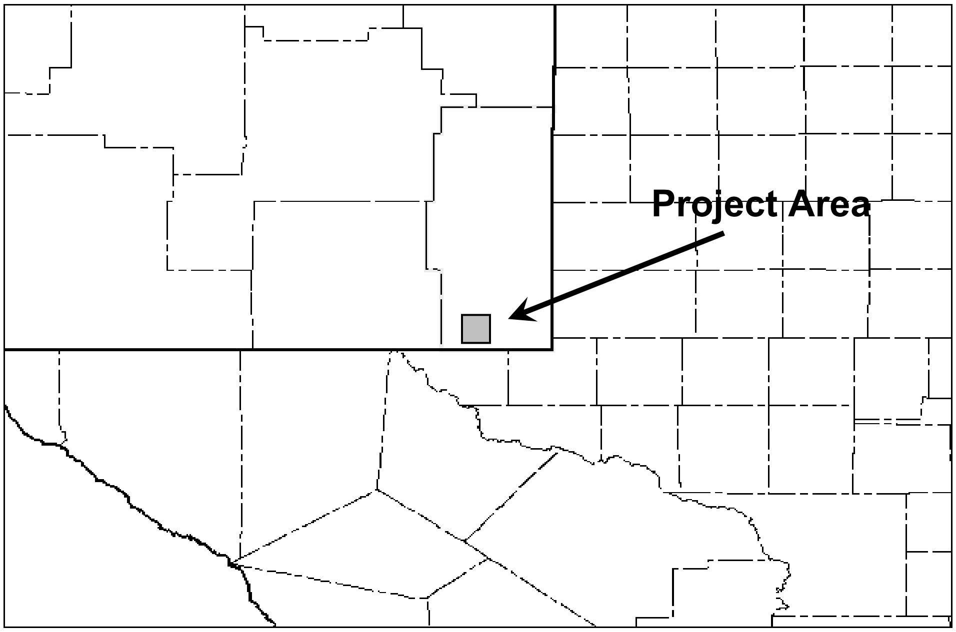

Figure 3 – Location of Horizontal Drilling Project in SE New Mexico

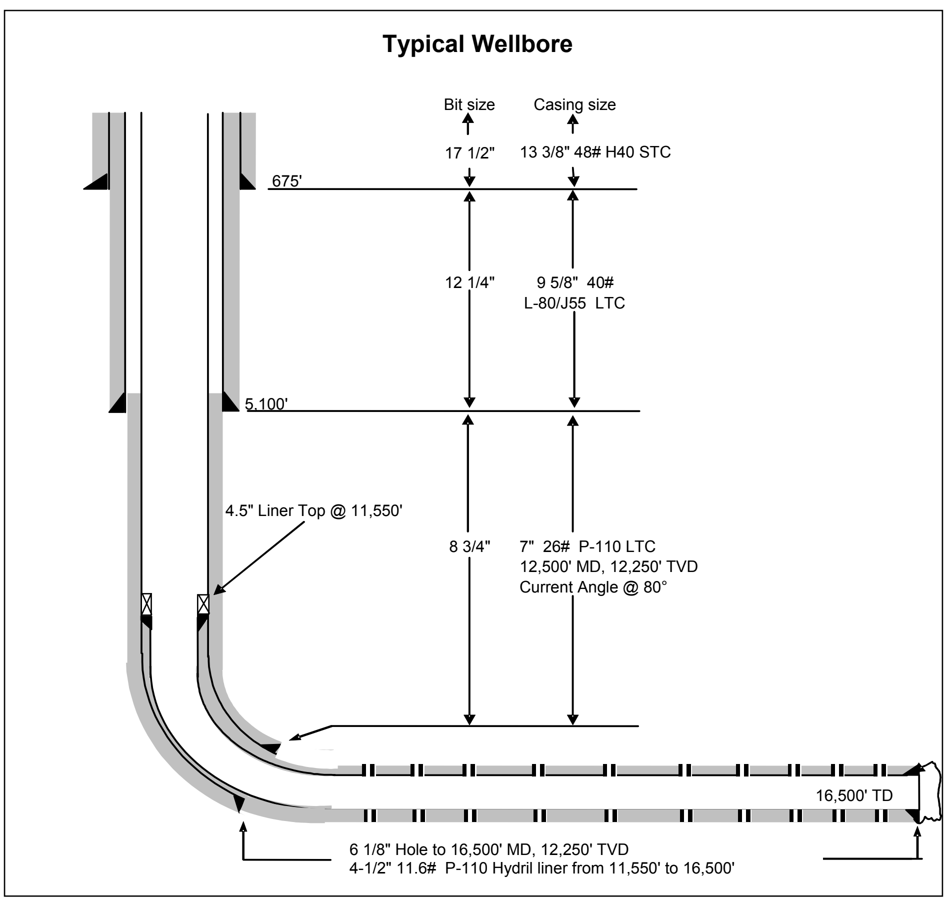

Figure 4 – Wellbore Schematic of Typical Horizontal Completion

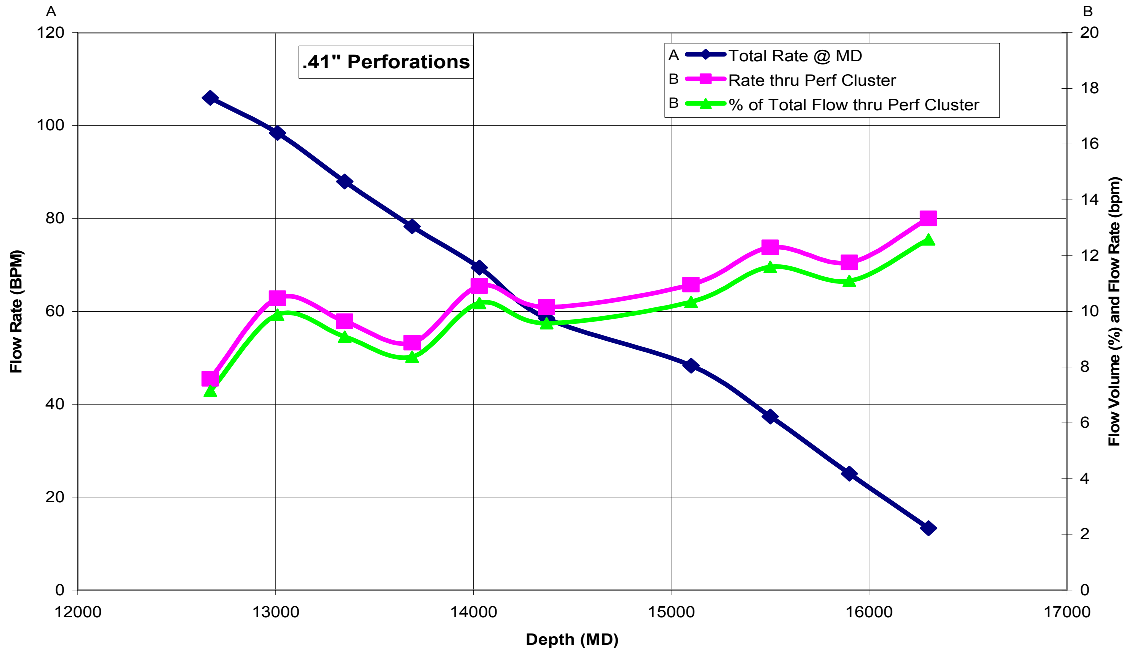

Figure 5 – Limited-entry Rate Distribution from Perforation Design

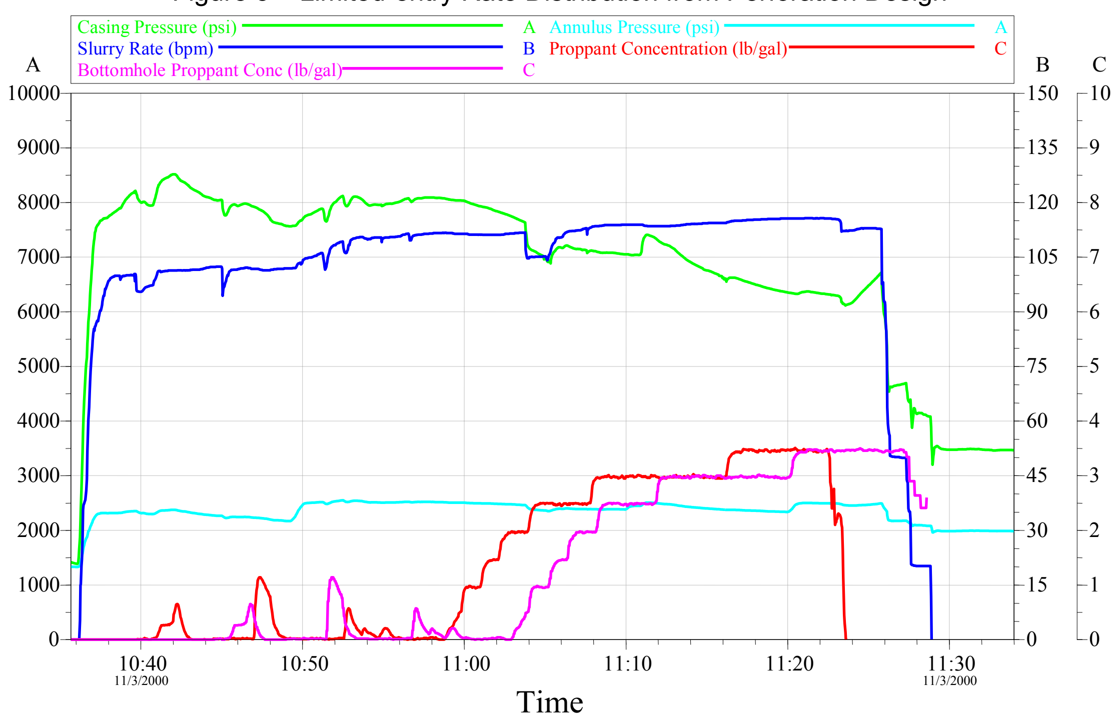

Figure 6 – Fracturing Treatment Chart From ASC Horizontal Well
The designed treatment rate was reached early in the job.

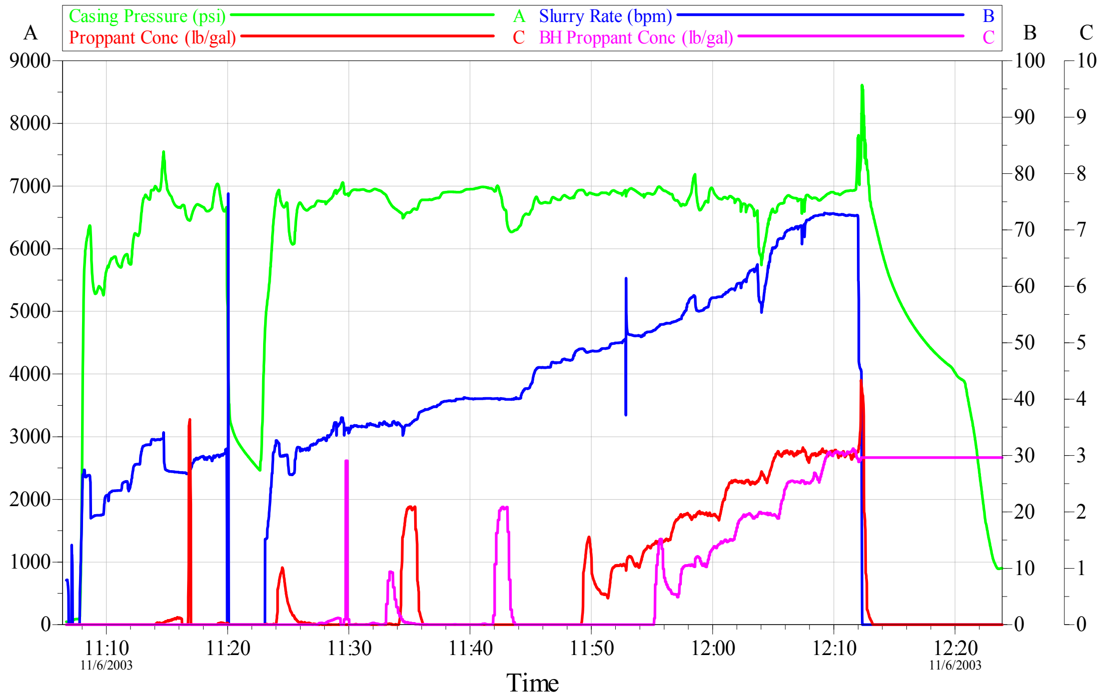

Figure 7 – Fracturing Treatment Chart From Conventional Cement Horizontal Well
The designed treatment rate was not reached until the very end of the job.

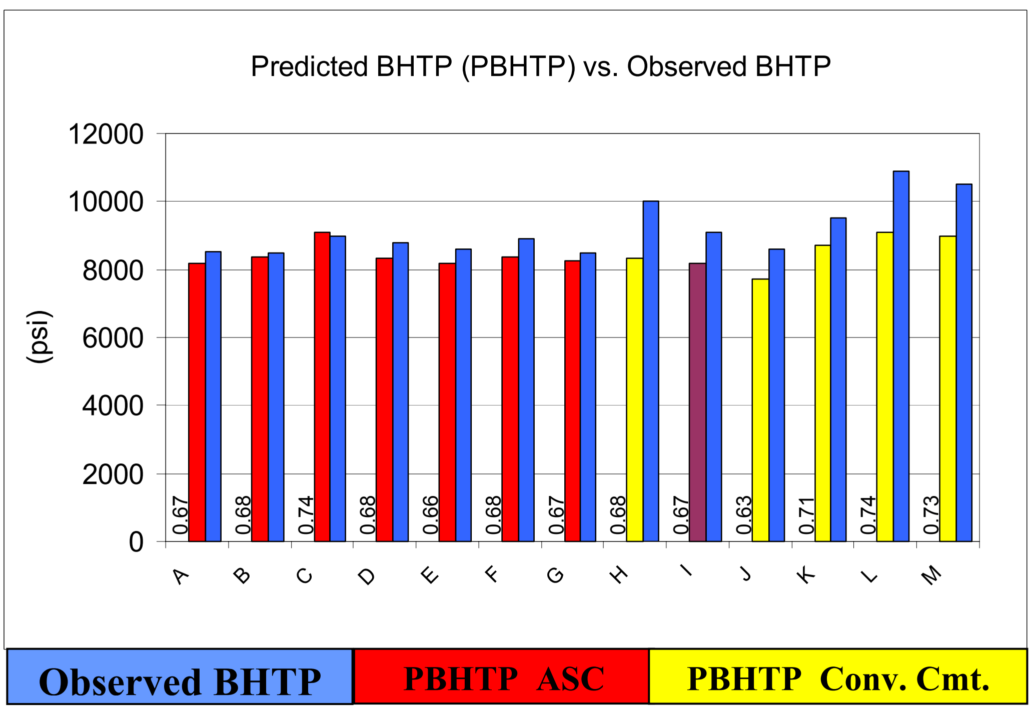

Figure 8 – Observed bottomhole treating pressures (Observed BHTP) on wells with conventional cement were significantly higher than predicted bottomhole treating pressures (PBHTP). Well I was an uncemented liner completion.

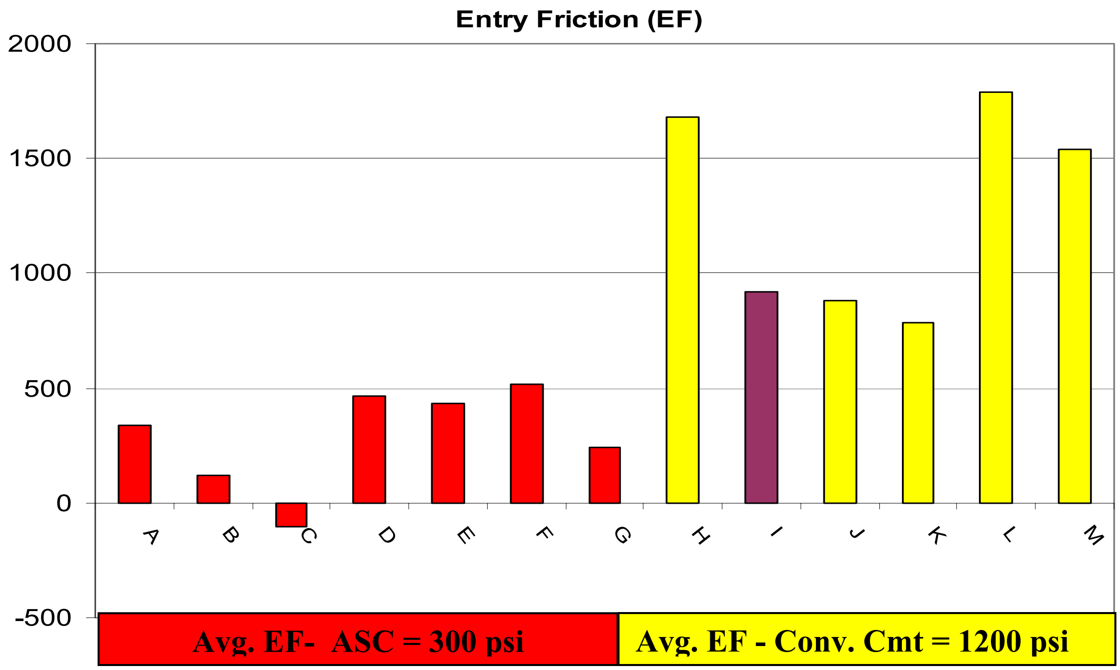

Figure 9 – Average Entry Friction for ASC Wells was 300 Psi. Average entry friction for conventional cement wells was 1200 Psi. Well I was an uncemented liner completion.