"PIPELINING," VISCOUS FINGERING PROP FRACTURE TECHNIQUE FINDS WIDE SUCCESS IN PERMIAN AND DELAWARE BASINS

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ABSTRACT

During the past two and a half years, a new fracturing technique has been developed to selectively place proppant across a well's producing interval. The new technique, termed "pipelining," has been employed in hundreds of wells in the Permian and Delaware basins. This technique utilizes high differential viscosity to selectively place high concentrations of proppant across the well's producing zone. This technique involves specialized design and iterative modeling procedures.

In the paper, we will discuss the ongoing improvement of the "pipeline" fracture design and present numerous case histories of various sand members of the Delaware formation throughout Southeastern New Mexico as well as other producing horizons in the Permian Basin.

The authors feel that the "pipeline" fracture technique, combined with intense quality control and aggressive forced closure, greatly enhances the ability to selectively place proppant in the pay zone and allows for highly conductive propped fractures for much greater lengths than were heretofore felt possible.

INTRODUCTION

"Pipeline" fracturing is the result of a program to develop and optimize a completion technique for selective placement of proppant in relatively thin pay intervals. This new technique takes advantage of the viscous fingering action between the high viscosity crosslinked pad and a much lower viscosity sand laden linear gel.

After observing the differential viscosity effects in laboratory studies, viscous fingering was first used in acid fracturing to stimulate wells. Figure 1 illustrates observed viscous fingering where borate crosslinked fluids are pumped followed by an uncrosslinked linear gel between plexiglass plates. After first observing this phenomena, we decided to attempt to develop a propped fracture stimulation technique that utilizes the observed differential viscosity effect to selectively place proppant across thin pay intervals.

The first application for the "pipeline" fracture technique was in relatively thin Brushy Canyon pay zones in wells in Southeast New Mexico. The Brushy Canyon is the lowermost member of the Delaware mountain group and consists of sand and shale sequences with an occasional thin dolomite layer[1]. The Brushy Canyon sands were deposited as density flows (turbidities) off the edge of the Delaware basin. Oil production is from stratigraphically trapped lenticular sandstone bodies overlain by shale and/or dense dolomite. The productive interval often consists of the upper portion of a thick (> 100') permeable sand body separated from an upper adjacent water-bearing sand by only a thin shale barrier (see Figure 2). Solution gas is the primary drive mechanism for Delaware.

Delaware pay zones typically have water saturations of 50% or greater, depending on the sand grain size and capillary pressures. The high initial water saturation generally exceeds the sand's irreducible water saturation, resulting in mobile water within the pay zone. It should be stated that, regardless of how successful the "pipeline" fracture technique is in selectively placing proppant across the pay interval, the stimulated pay zone will still produce in-situ water.

Most conventional fracture treatments of these thin pay zones result in high water cuts due to the zone's proximity to water-bearing rock. Our initial attempt to develop a technique to selectively place proppant across the pay interval was to utilize low viscosity linear gels in wells where significant fracture barriers existed below the zone of interest. Some success was achieved in the Brushy Canyon sands using low viscosity "banking" type fluids. However, this technique had only limited application due to the fracture barrier requirement. Other operators in the Delaware Basin have pumped low viscosity fluids at low rates in an attempt to stay in zone. These treatments were generally small and enjoyed only minimal success. The use of a low viscosity gel for proppant transport allows for only low sand concentrations to be pumped resulting in minimal propped fracture width and fracture conductivity. Based on our experience in the fracture stimulation of multiple reservoirs throughout the U.S., the authors feel very strongly that minimization of pump rate and viscosity are very poor approaches to attempt to stay in zone.

The first "pipeline" fracture treatment was pumped on a Brushy Canyon well containing a 15' pay interval 30' above and 40' below water bearing sand sections. Due to the pay zone's proximity to water, a conventional fracture treatment of this well would result in a high water cut. A GDK radial model for pad size and a 2D GDK confined height model for the volume of proppant laden fluid was used to design the first treatment.

This first "pipeline" fracture stimulation was highly successful relative to the post-completion performance of offset wells, resulting in a high oil production rate and a low water cut. Post-fracture buildup analysis of the well indicated a highly conductive (greater than 30,000 md ft) propped fracture greater than two hundred feet in length.

Since the first "pipeline" fracture jobs were pumped, we have found that the initial design technique resulted in excessive proppant volumes and have refined the procedure to utilize an iterative method of calculating the volume of proppant laden fluid. This modified design approach will be discussed in more detail in the theory section of this paper.

Since the first "pipeline" fracture treatment, over 250 "pipeline" jobs have been pumped, primarily in Southeastern New Mexico. This new technique has also been used to stimulate thin zones in Mississippi, Kansas and the Texas Panhandle. Successful application has also been achieved in the San Andres, Devonian, and Clearfork formations of the Permian Basin in West Texas. In the results section of this paper, we will focus on the long term results of selected Delaware wells completed with "pipeline" fracture treatments, primarily in Phillips Petroleum Company's Cabin Lake (Delaware) field in Eddy County, New Mexico (shown in Figure 3).

THEORY AND OBSERVATIONS

Viscous fingering has long been observed in the oil industry, having both positive and negative effects, depending on the situation. From a negative standpoint, viscous fingering greatly reduces the oil displacement efficiency in waterfloods with viscous secondary oil. To remedy the problem, operators have attempted to viscosify or emulsify injection water ahead of the primary injection water or CO_2 floods throughout the world. In 1968, John Tinsley developed a well stimulation technique utilizing the viscous fingering effect called My-T-Acid. The technique involved pumping crosslinked polymer gels or highly viscous fluids ahead of low viscosity acid in an effort to etch the face of a created fracture with acid in a heterogenous manner.

Some oil companies have reported[2] pumping viscous pads ahead of linear gels in proppant fracturing. However, to the authors' knowledge, no one has attempted to synergistically utilize the viscous fingering effect and aggressive forced closure to selectively place proppant in a particular interval.

The "pipeline" fracture technique differs from previous attempts to stay in zone in that it works to selectively place proppant across a particular interval in the presence of a hydraulic fracture that has grown to great heights above and below the zone of interest. Figure 4 shows typical proppant placement resulting from a conventional fracture treatment where multiple layers exist. Figure 5 illustrates what the "pipeline" fracture technique attempts to do. The authors feel that some differential rock properties need to exist to achieve the optimum "pipeline" effect (see Figure 6). We believe the following criteria must be met for the "pipeline" technique to be successful.

1. The crosslinked gel pad must have 30 to 50 times the viscosity of the proppant laden linear gel.
2. The zone of interest should have a Young's Modulus somewhat lower than the underlying and overlying rock to provide for enhanced fracture width needed to make efficient use of the differential viscosity.
3. Only the zone of interest should be perforated. The "pipeline" fracture technique has no chance of success in open hole completions or in wells where the perforated interval extends beyond the pay zone.
4. Aggressive flowback at a minimum rate of 1 BPM, immediately following pump shut down, is needed to ensure forced closure on the proppant in the pay zone and that minimal proppant settling occurs before gel breakdown.
5. The pad should be a perfect proppant transport fluid. For example, if a borate crosslinked fluid is used, it must have a final pH above 9.6 to retain sufficient viscosity to support the proppant should it settle into the crosslinked medium before fracture closure. In high temperature reservoirs, the crosslinked pad is designed using higher concentrations of polymer to maintain sufficient viscosity throughout the job. This provides for good fracture width in the zone of interest, perfect proppant transport ability, and the high differential viscosity needed for the "pipeline" effect.

It should be noted that, in wells in which the pay zone is not close to water bearing intervals, or in wells possessing multiple pay intervals in close proximity to each other, a conventional fracture treatment using perfect proppant transport fluids may be the technique of choice.

Where "pipeline" treatments prove most advantageous is in cases where there is a need to selectively place proppant in a pay interval in which separate water or gas producing zones exist in close proximity. Some "pipeline" treatments have been used to stimulate thin, permeable pay zones where no frac barriers existed and water was not a problem. If the zone of interest possesses moderate to high permeability, the "pipeline" fracture technique can prove to be the most economical approach by minimizing the amount of proppant required to achieve a 200' to 300' propped fracture.

As mentioned in the introduction, a GDK radial model is used to design the crosslinked pad necessary to create a hydraulic fracture of the required length. We typically design the pad to create a fracture with a width of at least .2" at the desired propped length. We then use an iterative spreadsheet model together with the GDK radial model to optimize the amount of proppant to be pumped. Table 1 shows a typical "pipeline" fracture design. It should be noted that the pad volume is generally quite larger than the proppant laden linear gel stages. In Delaware wells, a typical "pipeline" treatment consists of 5,000 to 10,000 gallons of linear gel prepad, 30,000+ gallons of crosslinker gel pad followed by less than 5,000 gallons of proppant laden linear gel carrying an average of 8 ppg sand. The proprietary design procedures we use take into account the proximity of water to the zone of interest and involve a great deal of iteration to compensate for proppant smearing within the created fracture.

During the past two and a half years, we have discovered that by pumping a prepad of linear gel ahead of the crosslinked pad, we are able to achieve longer propped fracture lengths without using excessive volumes of the crosslinked fluid. The very high viscosities required of the pad to help achieve the "pipeline" effect create wide radial fractures resulting in short fracture lengths. By pumping a less viscous prepad ahead of the crosslinked pad, we are able to create the desired propped fracture lengths more economically.

As is common to all new well stimulation methods, the "pipeline" fracture technique has had failures. Two "pipeline" fracture treatments were attempted on wells in the Hugoton Field in Kansas. We designed each treatment to attempt to selectively place proppant in fairly close proximity to water bearing intervals. Both "pipeline" treatments resulted in high water production with only minimal stimulation. The pre-design evaluation of the open hole logs for lithology and rock mechanical properties indicated that there was no significant variation in Young's Modulus between the pay interval and the overlying and underlying rock. This led us to conclude that, in wells with little or no differential rock properties, the "pipeline" fracture technique has little chance for success.

QUALITY CONTROL AND FORCED CLOSURE

It is the authors' opinion that intense quality control[3] and aggressive forced closure[4] are extremely important to the success of a "pipeline" fracture treatment. As discussed earlier, a "pipeline" treatment requires a high viscosity crosslinked pad capable of maintaining it's viscosity throughout the pump time to achieve the viscous fingering effect. By conducting on site pilot tests of the fracturing fluids at reservoir temperature, we can assure the operator of having the required differential viscosity for the job. This pre-job pilot testing of the fracturing fluids has resulted in some service companies having to modify their treating methods after it was discovered that some of their breaker accelerators tend to crosslink linear gels. Even moderate crosslinking of the sand laden linear gel stages would eradicate the viscous fingering effect and thus the success of the "pipeline" treatment. Most importantly, the fracturing fluids must have complete breakdown post-closure. With the minimal amount of sand pumped in a "pipeline" treatment, it is an absolute necessity that complete breakdown of the fracturing fluids be accomplished for effective well clean-up. We specify 2-3 centipoise at 511 reciprocal seconds for produce frac fluid at ambient temperature.

Forced closure is essential for a "pipeline" fracture treatment to be successful. We feel that by rapidly and aggressively flowing wells back after pump shut-down, we accomplish reverse gravel packing--placing the proppant near the wellbore up against the perforations. Accelerating fracture closure following a "pipeline" treatment works to prevent the proppant from settling into the crosslinked fluid below the zone of interest. This action is imperative to the success of the job. It should be noted that we have calculated very high propped fracture conductivities from post-fracture buildup analysis of wells completed with the "pipeline" fracture technique. The high fracture conductivities (> 30,000 md ft) tend to indicate that there has been some proppant settling within the zone of interest. The migration of proppant left a highly conductive area of the fracture open just above the proppant pack. We believe that this open fracture is a result of the viscous fingering effect and is responsible for some of the success of the "pipeline" technique.

Typical flowback rates following "pipeline" treatments are 1 BPM immediately upon shutdown. Following fracture closure, some operators will slow the flowback rate down to .5 BPM. Most operators, however, continue to flow the well at these aggressive rates until the well starts cutting oil or gas.

FIELD RESULTS AND CASE HISTORIES

1. The first case history we will discuss is the use of the "pipeline" fracture technique to selectively place proppant in a Devonian well near McCamey, Texas. The upper, more permeable portion of the thick Devonian sand had incurred CO_2 breakthrough and had subsequently been squeezed off from the wellbore. The remaining 150' of the Devonian sand was re-perforated and stimulated with a "pipeline" fracture treatment consisting of 20,000 gallons of crosslinked gel pad followed by 10,000 gallons of proppant laden linear gel. It should be noted that this job occurred early on in the development of the "pipeline" fracture technique. Today, we would likely design this treatment to include a linear gel prepad, a greater volume of crosslinked gel pad, and a lesser amount of proppant. However, the original treatment was a great success. The crosslinked pad did create a radial fracture that grew to encompass the upper and lower sections of the sand body. Due to the viscous fingering effect, we were able to successfully stimulate the re-perforated lower permeability section of the Devonian sand without placing proppant in the upper CO_2 saturated region.

The primary difference between this case and the Delaware cases to follow is the large (150') re-perforated lower interval. In this particular case, we employed a combination of high differential viscosity and banking/settling fluids. This combination worked to ensure that we did not prop open the CO_2 break-through portion of the rock but did place proppant in the re-perforated unflooded section.

2. The remainder of our field examples involve Delaware wells in Phillips Petroleum Company's Cabin Lake (Delaware) field in Eddy County, New Mexico (see Figure 3). The results of 23 "pipeline" and two conventional fracture treatments pumped on eleven different Cabin Lake (Delaware) wells are reported in Tables 2-4.

For comparison purposes, in Table 2 we listed the initial stabilized oil and water production rates from several Cabin Lake wells completed with conventional fracture methods. These were primarily polyemulsion and/or conventional crosslinked treatments pumped on lower Delaware pay intervals. These same wells were recently worked over to complete additional upper thin Delaware pay zones utilizing the "pipeline" fracture technique. Following completion of the new zones, the wells were returned to production, with all completed intervals open to the wellbore. Table 2 shows the initial stabilized oil production from the subject wells to be relatively good with a WOR of 2.3. Table 3 lists the same wells with the number of zones completed conventionally prior to the workover, production before and after the workover, and the WOR before and after the workover. Inspection of Table 3 reveals that each workover employing the "pipeline" fracture technique significantly increased the well's oil production rate. It is important to note the effect that the additional "pipeline" completion work had on the well's WOR. The composite WOR of the wells that were worked over using the "pipeline" fracture technique exclusively was reduced from 4 to 2.1. We believe that the reduced WOR is due to the "pipeline" treatment's ability to selectively place proppant across the oil pay zone without stimulating water bearing rock above and below the pay interval.

Table 4 lists several Cabin Lake wells that were re-completed in upper thin Delaware pay intervals again utilizing the "pipeline" fracture technique. Following completion of the new zones, these wells were returned to production to produce only the newly completed intervals. Again, the "pipeline" fracture technique was very successful in stimulating oil production in each well. The composite WOR for the re-completed well that used only the "pipeline" fracture technique was .87, significantly less than the 2.1 composite WOR from the Cabin Lake workover wells shown in Table

3. These results strengthened our belief that the "pipeline" fracture technique can successfully place proppant across the zone of interest without stimulating adjacent water bearing zones.

Central to the success of a "pipeline" fracture treatment on a Delaware well is that it be employed when well conditions require selective placement of proppant in a zone within close proximity to water. We feel that, despite the success of the "pipeline" treatments, the new technique is not applicable to every well. To illustrate this point, we included data from two Cabin Lake wells, the Livingston Ridge #1 and the James "E" #11, that were recently worked over to complete additional Delaware pay using a single conventional fracture treatment. Each well possessed numerous Delaware pay intervals separated by thin shale/dolomite barriers and low permeability sand sections with little mobil water. The gross pay interval for each well was approximately 300'. The well conditions for these two wells were ideal for a conventional fracture treatment using a perfect proppant transport fluid.

Tables 3 and 4 show that the conventional fracture treatments were successful in stimulating oil production in the two wells with an average stabilized WOR of .85. With each well possessing 300' of gross pay to accommodate radial fracture growth and with no water bearing zones between the pay intervals, we were able to design a treatment that stimulated the oil pay intervals without propping open water bearing rock to any great extent outside the 300' gross interval.

The results of the Cabin Lake (Delaware) workover program are shown in Figures 7 through 16. The workover program commenced in July, 1992 and utilized the "pipeline" fracture technique exclusively with the exception of the two wells discussed above. Figure 7 is a plot of Cabin Lake oil and water production before and during the workover program. The plot works to illustrate the effect the "pipeline" workovers had on the field's oil production and WOR. Oil production increased from 750 BOPD to 2150 BOPD while the field's producing WOR was reduced from 4.5 to 1.2.

Figures 8 through 13 show oil and water production for wells that were worked over using the "pipeline" technique. Like the composite plot, these individual plots strongly illustrate the success of the "pipeline" fracture technique in stimulating oil production while reducing the well's WOR.

Figures 14 and 15 show oil and water production for the two wells that were worked over using conventional fracture stimulation methods - the Livingston Ridge #1 and the James "E" #11. The plots show that a conventional fracture treatment was successful in stimulating each well's numerous pay zones over a 300' gross interval.

Figure 16 is a semi-log plot of the James "A" #7's oil production. Following the well's initial completion in January, 1991, the well experienced a production decline typical of Cabin Lake (Delaware) wells completed with conventional fracture methods. In November, 1992, the well was worked over using the "pipeline" fracture technique to fracture stimulate upper thin Delaware pay intervals. Although we have only five months of post-workover production data, the well appears to be on a less aggressive decline than before. We believe that the "pipeline" fracture treatments pumped on this well created highly conductive, selectively placed propped fractures resulting in improved stimulation of the new oil zones when compared to the results of conventional fracture treatments.

Because of their proximity to water, many thin Delaware pay zones completed in Cabin Lake wells using the "pipeline" fracture technique would have been deemed uneconomical to develop using conventional stimulation means. Cabin Lake, like many new Delaware fields in Southeast New Mexico, is a very remote lease. Due to their remote location, SWD costs are high for most new Delaware leases; produced water costs approximately $2/bbl to be trucked to an approved SWD site. These costs must be considered when drilling a new Delaware well or completing a new zone in an existing well. The "pipeline" fracture technique, by selectively placing proppant across the zone of interest, gives the operator the flexibility to test and complete thin Delaware pay zones in close proximity to water.

In addition to the successful stimulation of thin Delaware pay intervals, the Cabin Lake operator found other advantages to using the "pipeline" fracture technique:

1. Clean up time following a "pipeline" fracture treatment proved to be about half the time required for a conventional treatment. We feel this is due to pumping a much less amount of sand per the "pipeline" fracture design along with the aggressive use of forced closure.

2. Sand-related pump failures of wells completed with the "pipeline" fracture technique were significantly less frequent than those completed with conventional fracture treatments. Again, we feel this is due to less sand being pumped and the use of forced closure.

CONCLUSIONS

1. The "pipeline" fracture technique has proven to be a valuable tool for selectively placing high concentrations of proppant across relatively thin pay intervals resulting in highly conductive propped fractures.

2. By working to selectively place proppant across the pay interval only, the "pipeline" fracture technique has been shown to successfully stimulate oil production, while reducing the producing WOR of wells, resulting in a reduced oil decline rate.
3. The "pipeline" fracture technique can enhance the economics of a well in several ways: 1) successful stimulation of the productive interval resulting in long term production, 2) low WOR's resulting in reduced SWD costs, 3) reduced clean-up time following the treatment, and 4) reduced number of sand-related pump failures after the well is placed on pump.

4. The "pipeline" fracture technique is not applicable in all wells. It is most effectively used to stimulate thin productive intervals in close proximity to water or gas bearing zones.

5. We have worked to enhance the "pipeline" fracture technique by pumping a large volume of linear gel as a prepad ahead of the crosslinked gel pad in order to achieve greater propped fracture lengths within the pay interval. In addition, we continue to refine the "pipeline" design procedure in an effort to optimize the use of fracture fluid and sand through the post-frac evaluation of wells.

6. The authors feel that there are numerous other producing formations that could greatly benefit from the "pipeline" fracture technique. A thin producing interval within a thick rock section or in close proximity to water or gas can benefit from the "pipeline" fracture technique's ability to selectively place proppant across the zone of interest.

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2. Verbal communication with Cecil Parker, Conoco.

3. Ely, J.W.; Wolters, B.C.; and Holditch, S.A.: "Improved Job Execution and Stimulation Success Using Intense Quality Control," Paper presented at the 37th Annual Southwestern Petroleum Short Course, Lubbock, Texas, April 18-19, 1990.

4. Ely, J.W.; Arnold, W.T.; and Holditch, S.A.: "New Techniques and Quality Control Find Success in Enhancing Productivity and Minimizing Proppant Flowback," Paper SPE 20708 presented at the 1990 Annual Technical Conference and Exhibition, New Orleans, LA, September 23-26, 1990.

Table 1
Example of "Pipeline" Fracture Design

Fluid Type	Fluid Volume (gals)	Sand Concentration (ppg)	Sand Volume (lbs)	Injection Rate (bpm)
35# Linear Gel-prepad	10,000	--	--	20
35# CX Borate	30,000	--	--	20
35# Linear Gel	500	2.5	1,250	20
35# Linear Gel	1,000	5.0	5,000	20
35# Linear Gel	1,500	7.5	11,250	20
35# Linear Gel	2,000	10.0	20,000	20

Table 3
Production Results of Cabin Lake (Delaware) Well Workovers Using the "Pipeline" Fracture Technique

Well Name	# of Zones		Production Before		Production After		WOR	
	Old	New	Oil	Water	Oil	Water	Old	New
James "E" #4	4	3	40	90	193	130	2.3	.7
James "E" #5	2	3	30	40	180	180	1.3	1.0
James "A" #6	2	2	20	240	81	243	12.0	3.0
James "A" #7	4	5	20	50	130	220	2.5	1.7
Livingston Ridge #1*	3	6	45	90	158	100	2.0	.6
Livingston Ridge #2	4	1	40	250	70	280	6.3	4.0
Composite	--	--	195	760	812	1153	4	2.1**

*conventional fracture treatment
**composite of "pipeline" treatments only

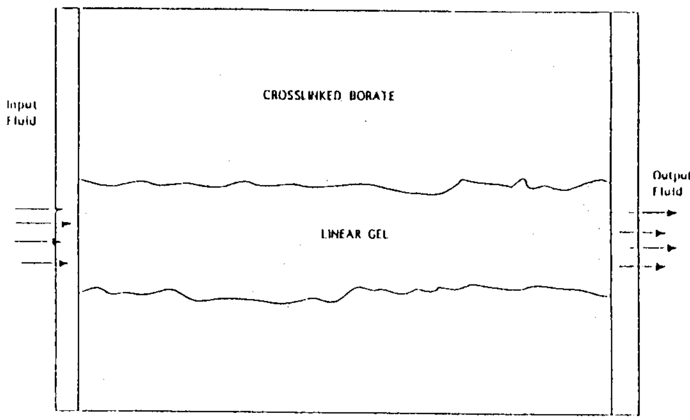
Table 2
Initial Stabilized Production of Cabin Lake (Delaware) Wells Completed With Conventional Fracture Treatments

Well Name	Stabilized Production		WOR
	Oil	Water	
James "E" #4	70	150	2.1
James "E" #5	75	100	1.3
James "A" #6	90	190	2.1
James "A" #7	50	120	2.4
Livingston Ridge #1	86	200	2.3
Livingston Ridge #2	100	200	2.0
Composite	471	960	2.3

Table 4
Production Results of Cabin Lake (Delaware) Wells Recompleted With "Pipeline" Fracture Treatments

Well Name	# of Zones	Oil	Water	WOR
James "E" #3	1	58	80	1.4
James "E" #13	1	400	75	.2
James "E" #6	2	86	141	2.3
James "E" #11*	6	172	197	1.1
James "E" #12	4	99	266	2.7
Composite	--	815	759	.87**

* conventional fracture treatment
**composite of "pipeline" treatments only



Dramatic depiction of "viscous fingering" seen when uncrosslinked fluid (linear gel) follows crosslinked borate gel during laboratory tests observing viscous gel phenomena.

Figure 1

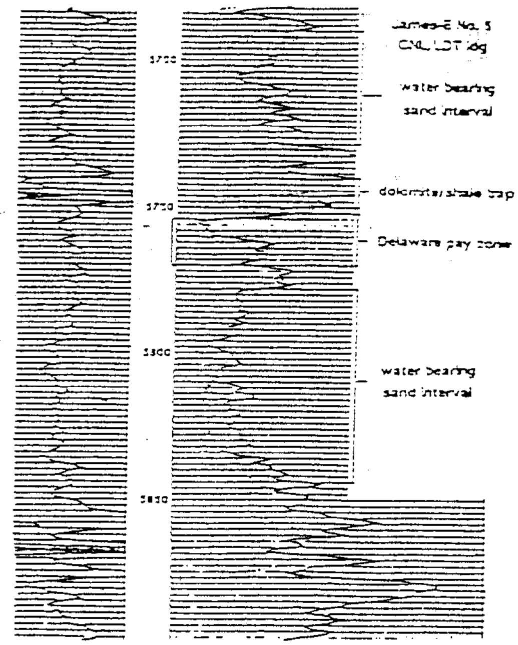


Figure 2

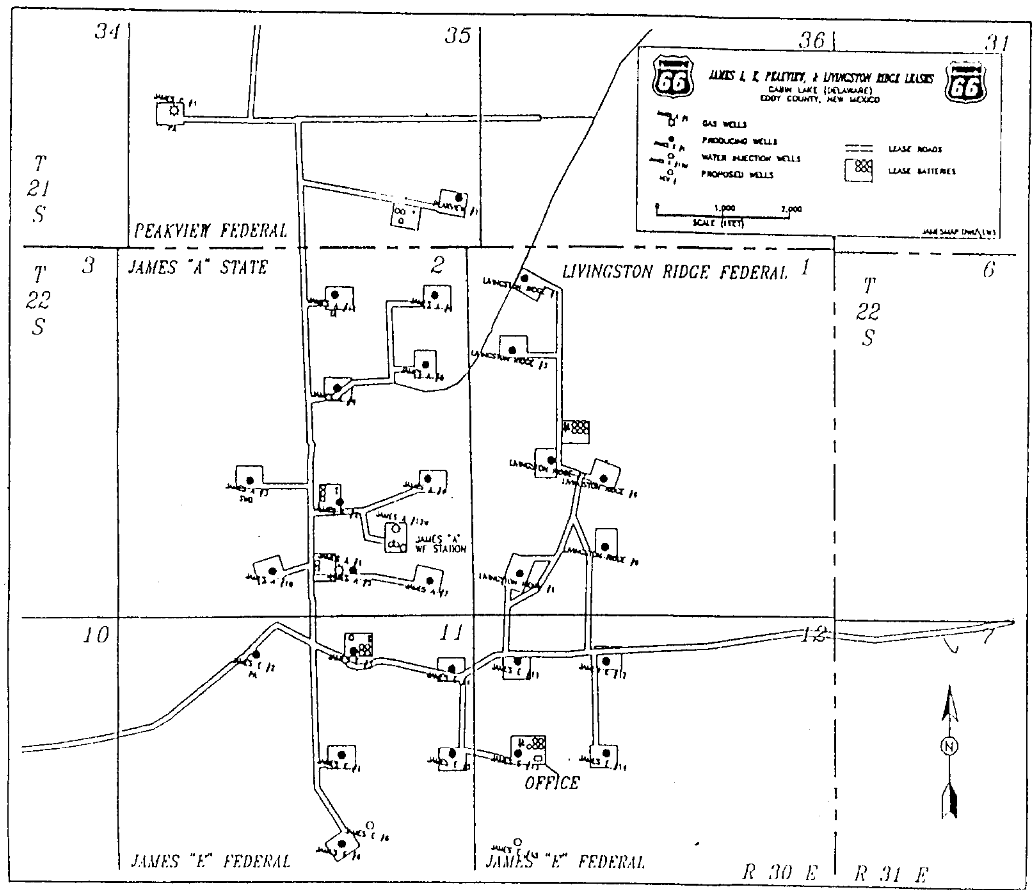


Figure 3

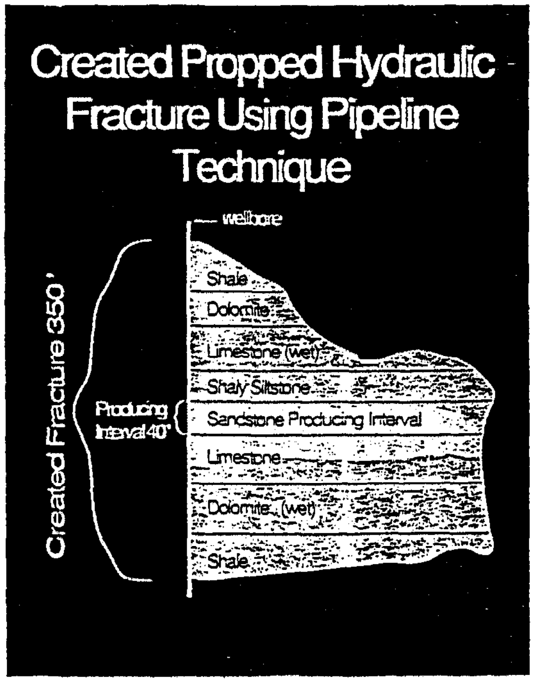


Figure 4

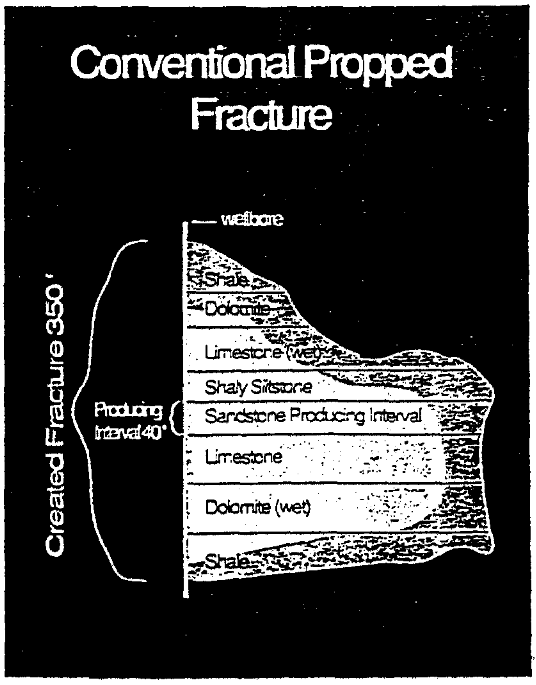


Figure 5

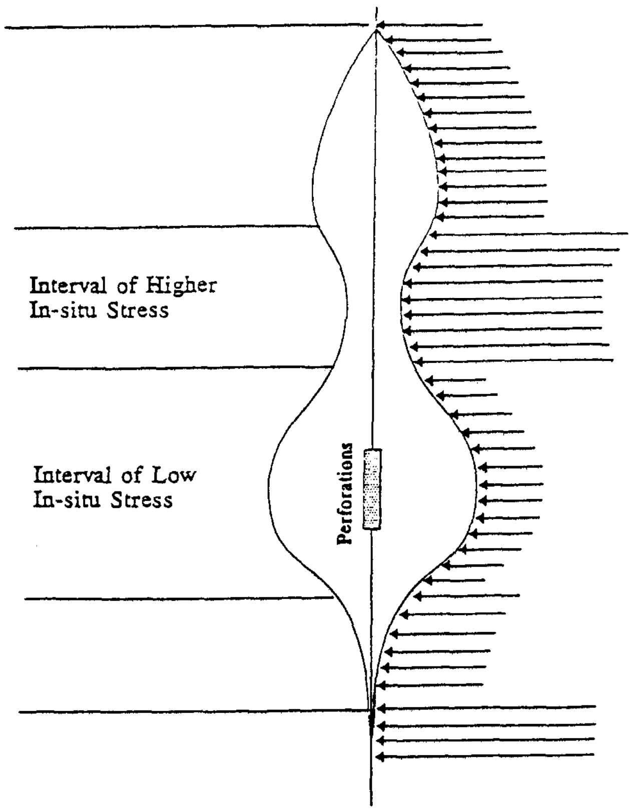


Figure 6 - Fracture width profile with in-situ stress contrast

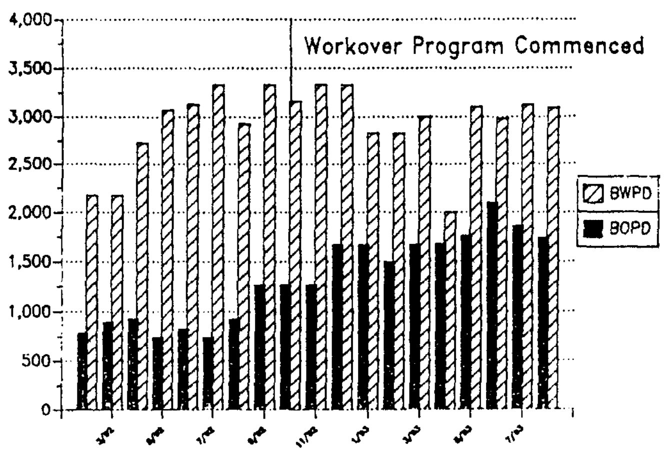


Figure 7 - Phillips Petroleum Company
Cabin Lake Oil & Water Prod.

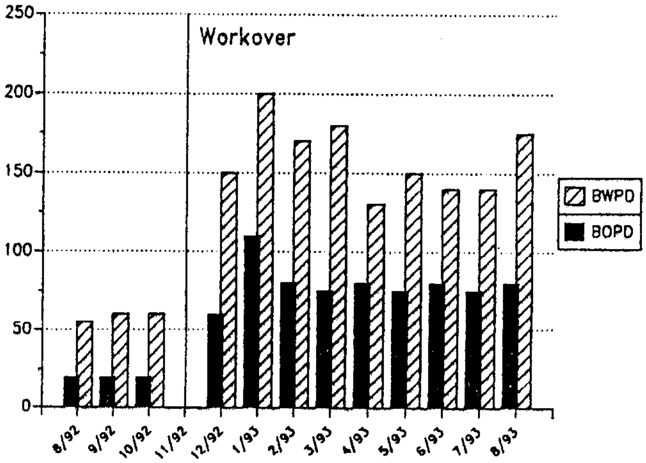


Figure 8 - Phillips Petroleum Company
James - A State #7

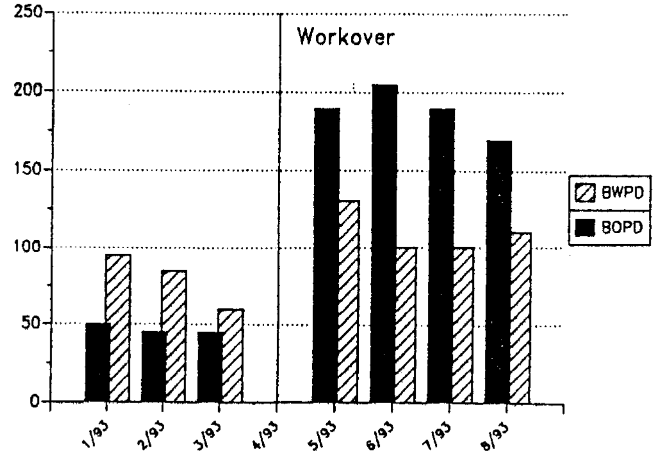


Figure 9 - Phillips Petroleum Company
James - E Federal #4

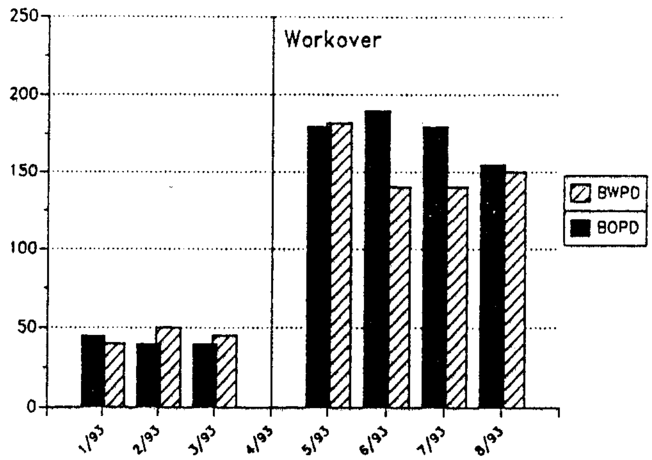


Figure 10 - Phillips Petroleum Company
James - E Federal #5

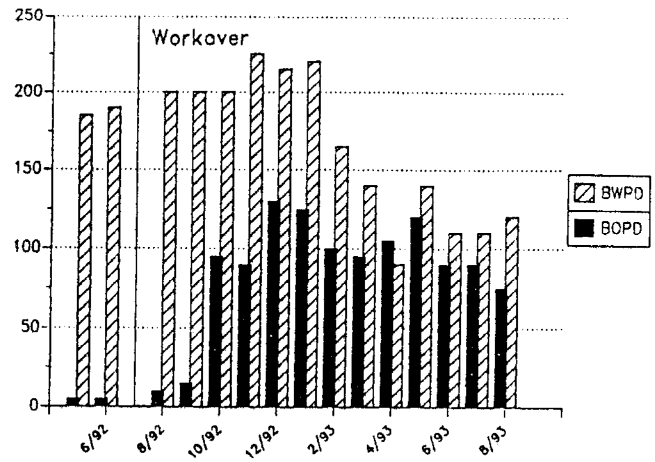


Figure 11 - Phillips Petroleum Company
James - E Federal #6

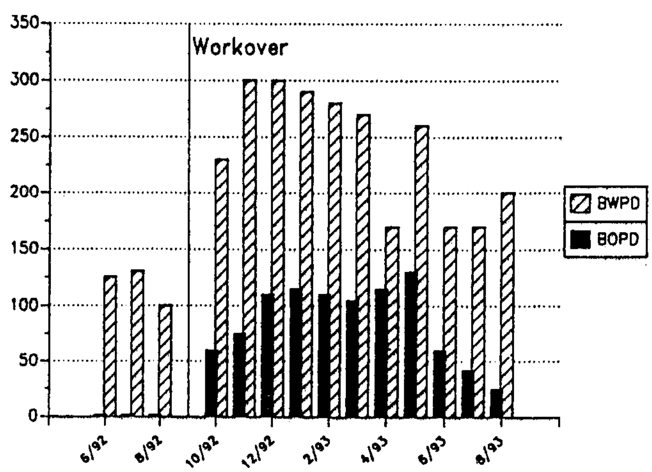


Figure 12 - Phillips Petroleum Company
James - E Federal #12

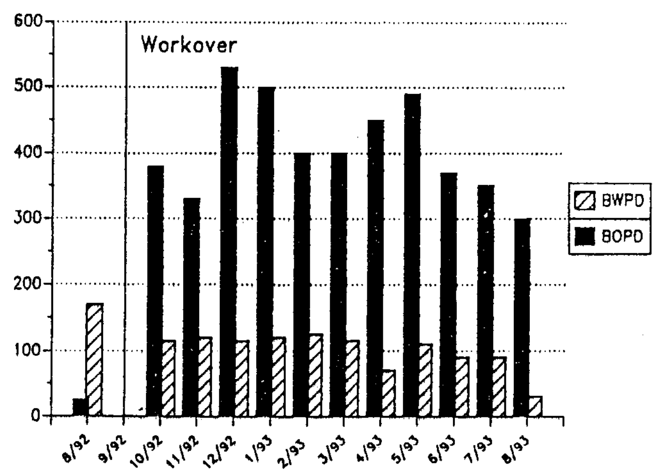


Figure 13 - Phillips Petroleum Company
James - E Federal #13

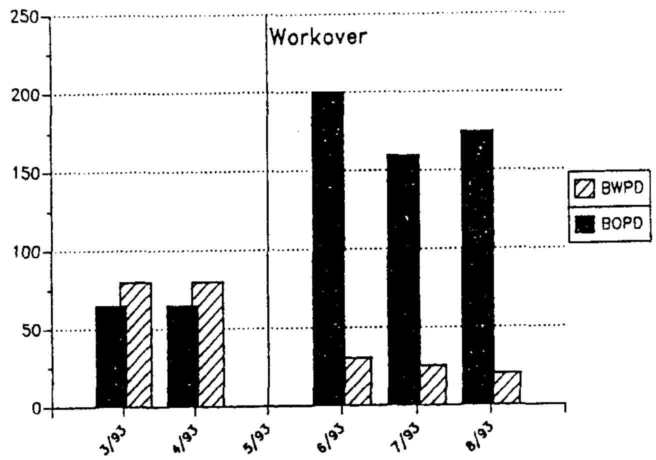


Figure 14 - Phillips Petroleum Company
Livingston Ridge #1

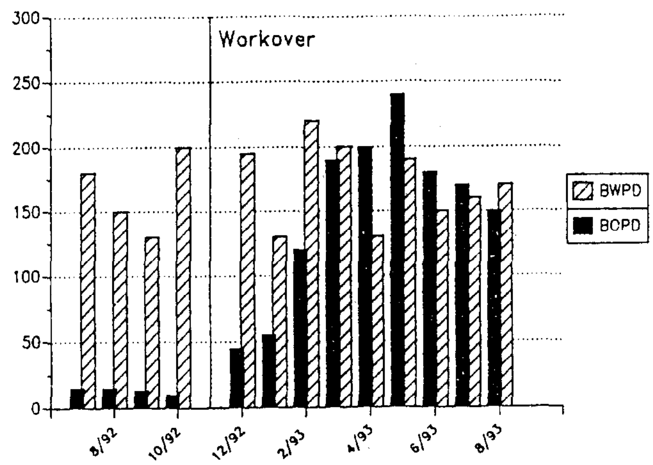


Figure 15 - Phillips Petroleum Company
James - E Federal #11

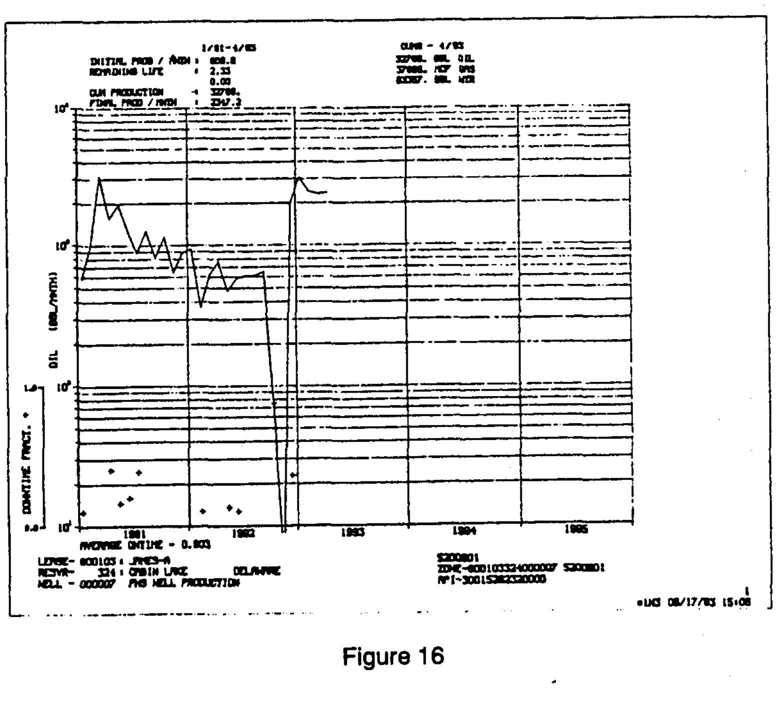


Figure 16