RESULTS OF RELATIVE-PERMEABILITY MODIFIER COMBINATION USED FOR FRACTURE-STIMULATION TREATMENTS

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Abstract

When stimulation treatments are performed on oil- or gas-producing zones with close proximity to (1) high-permeability streaks that produce water, or (2) other zones above or below the pay have a high water content or influx, stimulation fluid can enter the high water-bearing zones and cause unwanted water production. In such instances, water production from the formations may be excessive, requiring expensive separation and water disposal. Longevity of production may be curtailed, or the cost of separation and disposal may cause these pays to be abandoned. When rock-stress interpreted values are used in the stimulation design, one can often predict whether a conductive entry into an undesired section may cause production of water instead of hydrocarbon. Many wells with these problem conditions were not perforated and stimulated, resulting in further loss of potential production.

Occasionally, after a stimulation treatment has been performed, a water-control treatment may be attempted to reduce water production. The remedial treatments are expensive and are not always successful. Furthermore, if the remedial treatments are not placed in the correct portion of the fracture, the treatment can plug the formation, resulting in lost production.

This paper discusses field results of a fracture-stimulation treatment that includes a relative-permeability modification (RPM) chemical agent. The design objective was for the RPM to leak off into portions of the created fracture during the stimulation treatment and help prevent water production. Initial treatments were performed in April 1997 in the Brushy Canyon formation in southeastern New Mexico. The selected candidates treated were in the Delaware sand reservoir. Previous fracture treatments in this interval had resulted in water cuts greater than 60%, and the continued production of these wells had been uneconomical because of the presence of damaging scale and a subsequent decline in total fluid production; the water cuts would remain at 60 to 70%, but the total fluid production would decline.

In the 3 months following treatment, The RPM/fracture-stimulated wells averaged a 65% increase in oil production, a 122% rise in gas production, and a 60% decline in water production compared to wells previously stimulated without the RPM agent. In the 2½ years since these wells were brought on line, production has been maintained, while the wells previously treated without the RPM were usually plugged back within the first 3 months. Current production in the treated wells indicates a water cut of 25 to 20% with hydrocarbon production at 75% of the initial rate.

This technique has also been used in Kansas and in South American locations, where particular formations were not previously stimulated because of potentially high water production. Results indicate

that by using the techniques discussed in this paper, operators can stimulate these formations without adverse water cuts.

Introduction

Controlling water production has long been an oil-industry objective. An equal, if not greater, amount of energy is needed to produce 1 bbl of water compared to the same volume of oil. Often, each barrel of water produced is 1 bbl of oil not produced, and the water production exacerbates or creates other problems such as sand production, separation, and corrosion on tubulars and surface equipment. The reflective analysis of lifting water is normally given in terms of barrel-oil-equivalent (BOE) cost. This value reflects the energy required to lift sufficient produced fluid to gain 1 bbl of oil. For years, much research has been dedicated to the development of chemical systems that can selectively curtail water production without inhibiting oil production.

Intensive water saturation in the wellbore region may be caused by fractures, fissures, water fingering, water coning, or communication with a water zone through high-permeability streaks. Despite the cause, water production can result in the complete or partial loss of oil production within the same completion zones. Over time, various techniques have been introduced for controlling undesired water production-control.

Initially, two methods were used to curtail water-production problems: produced water was separated from the oil and disposed of, or a plugging agent was squeezed into the formation to stop water entry. Stringent government regulations controlling the disposal procedure resulted in increased costs. In one particular field, expenses incurred from the lifting cost, separation, and disposal of produced water reached $0.15/bbl. In the Permian Basin of west Texas, the average lifting cost (BOE) has been reported to be about $5.25, and the water-cut ratio is about 92%. The second curtailment method, which uses plugging agents or sealants as a conformance technique, has often proven counterproductive. Sealants are effective for certain oilfield problems, but when they block formation pores to prohibit the passage of water, they can also block all other fluids, including hydrocarbons.

Early conformance materials decreased the water-oil ratio (WOR) by various mechanisms. One material is a water-reactive agent that selectively plugged water-filled pore throats and/or increased water viscosity, thereby impeding its mobility, while altering oil production only minimally. Polyacrylamides (PAs) had previously been used in this technique with a limited degree of success.

As early as 1978, a water-soluble RPM was introduced for improving the water-to-oil ratio in producing wells. This polymeric material featured a different conformation and polymer/rock interaction than earlier products, and its performance was not significantly affected by mechanical shear or by exposure to oxygen, oils, acids, or other conventionally encountered oilfield fluids. The application design was simple:

- An aqueous dilution of the base material was placed in the formation at less than fracturing pressure.
- A rig was not usually necessary.
- No downtime was required.

- The well could be returned to production immediately.

This chemical material was thought to function through at least two discrete mechanisms that significantly altered the water-producing capabilities of sandstone formations. The control agent reacted with the rock face and bonded to it, increasing the material's resistance to removal by the flow of either water or oil and, thus, enhancing its longevity. The highly hydrophilic agent also hydrogen-bonded strongly to water through dipole-dipole and/or charge-dipole interaction. This bonding generated a substantial degree of pseudostructure in the water, resulting in increased viscosity.

Researchers thought that another contributing mechanism was related to the polymer's surface-active properties. The contact angle between a siliceous face treated with the material and a 2% solution of potassium chloride (KCl) was 22°, while the contact angle between an untreated surface and the same solution of KCl was 43°. The disparity in the angles indicated that the polymer agent should enhance oil production and retard water production.

A new design theory and procedure were developed for this water-control agent. Uncontaminated treating fluids were mandatory to safeguard permeability, and testing identified the material's compatibility with other chemicals used in the treatment. Early testing of the RPM polymer on Berea sandstone produced an 80 to 95% reduction in water permeability immediately after the treatment. Results from field applications were encouraging; they seemed to be characterized by a marked reduction in water, a lower fluid level during pumping operations, a rise in oil production rates, or combinations of all these effects.

Relative-Permeability Modification Agents

For the past 20 years, RPMs have proven attractive to the oil and gas industry because of their potential to minimize the risk factors and expenses inherent to conformance water management systems. Although the quintessential RPM agent should impede only the water in the formation, even the most effective agents slightly impair the effective permeability to hydrocarbons because the chemical partially fills the pore throats in the rock matrix. The objective, then, is for the treated interval to allow minimum water flow and maximum oil flow concurrently.

This objective can be achieved in a layered reservoir, because the RPM is assisted by the water saturation's impact on the effective permeability to water and oil. Inherently, the water-based RPM will penetrate much deeper into the water layer(s) than the oil layer(s). This disproportionate fluid entry enhances the treatment's water-reduction capabilities while minimizing any potential effect to the oil permeability.

An Examination of RPM Theory

Over time, a number of hypotheses have been advanced regarding the operative mechanism (or mechanisms) responsible for this disproportionate permeability reduction. In 1992, J. Liang, H. Sun, and R.S. Seright began experimenting extensively on disproportionate reduction in gel treatments. Their initial testing revealed a number of behavioral patterns arising from the use of various modification gels. These findings led to further study. In 1995, the same team of experts was able to discredit, or at least cast doubt upon, the theories that gravity, lubrication, wettability, or the swelling/shrinking effects of the gel play a major role in the phenomenon of disproportionate permeability.

In 1997, further research by Liang and Seright focused on the segregated pathway theory, which speculates that, on a microscopic scale, water-based gelants pass more readily through water pathways than through oil pathways. Results of their tests of Berea core samples supported the theory for oil-based, but not for water-based gels. Additional work in this battery of tests found that a balance between capillary and elastic forces was a factor in disproportionate permeability reduction in flow tubes and micromodels, but not in porous rock.

An Investigation of In-Situ RPMs

Early in 1998, an investigation was launched into the nature and function of RPMs, specifically in layered systems and transition zones. Since minimal laboratory data were available to verify proffered theories, researchers conducted flow tests to examine the actions of RPMs in these scenarios so they could directly apply such information to layered- and transition-type problems encountered by oil operators worldwide.

Water production through high-permeability streaks is customary in layered reservoirs. In this scenario, sealant cannot be easily placed into a particular layer without the neighboring strata being endangered. This layered, streaked-type of formation was thought to be the best candidate for an RPM treatment. The RPM's use was predicted to be beneficial if the modification agent could be sufficiently distanced from the interval so that water flow caused by differential pressure would be prevented through the interval. It was assumed that a force reduction of water flow through part of an oil- and water-producing transition zone would proportionally retard oil flow.

Because the chemical composition of the in-situ-generated modifier renders it impervious to shearing and damage from other downhole fluid systems, such an agent should be used as a preflush in fracture-stimulation treatments.

PCS-Enhanced Fracture Stimulation

The polymer conformance system (PCS), an in-situ-generated modification agent, was developed in 1995. PCS has the following advantages:

- It is nonplugging, selective, and nonhazardous to the wellbore.
- It introduces only minimal risk factors to the productive interval outside the wellbore.
- It neither causes nor sustains shear damage.
- It controls leakoff of conformance materials during fracture extension.
- It substantially improves oil-production levels.

Candidates for PCS include wells subject to water coning and high-permeability streaks. Because the agent is an in-situ-generated material, placement requires no pressure greater than the pressure expected for water.

The PCS is composed of two components: PCS-1, a low molecular-weight cationic, linear acrylate polymer, and PCS-2, a low molecular-weight polyether

PCS formulation requires that two components be diluted with water, then blended. The modification agent is then pumped downhole before the fracturing treatment. If needed, the pumping schedule could include a solvent preflush that removes deposits of asphaltenes and/or paraffins in the formation, preparing the zone for reactive contact. Cationic and nonionic surfactants are usually compatible; anionic surfactants are not.

After the modification agent is injected, and the fracturing treatment is placed, the well is shut in for 10 to 18 hours; in-situ polymerization occurs during this period. The conventional belief is that a "brush polymer" forms. The conceptual image of the mechanism is that this "brush polymer" bonds with the rock face and inhibits water production out of the pore-throat area.

A hypothesis exists that hydrophilic branches attached to this polymer extend into the pore-throat region and act as "microvalves" or "polymer brushes" in the presence of aqueous fluids. However, a hydrocarbon fluid flowing past this treated section would respond as if it were only exposed to a "water-wet" surface.

This type of conformance treatment has the following advantages: (1) pores are not physically plugged, (2) the treatment does not require rig time, (3) zonal isolation is unnecessary, (4) the agent has a "water-like" viscosity, and (5) the operation permits the required disproportionate reduction in permeability. Moreover, the PCS is designed only to reduce the effective permeability to water and not to act as a water shutoff material.

Selected Case Histories

To increase gas and oil reserves production, operators performed fracture-stimulation treatments on newly drilled wells in the Brushy Canyon formation (lower portion of the Delaware reservoir) of Eddy County, New Mexico. The Brushy Canyon formation consists of fine- to coarse-grain, partly shaly sandstone at the type locality. In the subsurface of the Delaware Basin, it consists of gray, fine- to very fine-grained sandstone that is partly shaly and silty and contains some medium, frosted quartz grains. Minor brown limestone and dark-gray silty shale beds are present. The pay can span a depth of about 1,000 ft. Because of the shelf environment to the north and the basin environment to the south, two widely varying rock sequences exist within much of the Permian Basin that contains the Delaware Basin. Pre-Pennsylvanian rocks are lithologically more uniform and generally represent a shelf environment. These pre-Pennsylvanian sediments are truncated to the north by various periods of erosion. Pennsylvanian sediments reflect a variety of depositional environments, but the broad stratigraphic subdivision used can be correlated with some degree of reliability throughout the area.

The Brushy Canyon formation features multilayered oil deposits with water intervals throughout the reservoir. The fracturing operation in the Brushy Canyon interval had limited success because the post-treatment results indicated that the generated heights of the fracture treatments were entering portions of the pay (both above and below) that had mostly high water saturation. Earlier fracturing treatments had produced poor results because high water-saturation intervals situated above and below the hydrocarbon-rich portions of the formation were unavoidable. Previous productivity was not cost-effective because of water cuts as high as 60 to 70%. Because of the varied mobility ratios of the water over oil in these wells, the production was usually initiated at a greater than 60% water cut. In fact, fluid production declined rapidly and consistently within 6 to 9 months after conventional stimulation jobs. Reducing water cuts in previously stimulated wells was attempted; all means of design interpretation (stress analysis, onsite monitoring of pressure response, and empirical-theoretical placement by means of fluid characteristics and rate-control methods) were used, but without success.

In time, the continued production became uneconomical because of the damaging scale and reduction in total fluids produced. Although the water cuts would remain at 60 to 70%, the total fluid produced would decline. After 6 months, oil production was below economical limits. The wells are drilled to be eventually completed into other intervals and have commingled production. This water production from the Brushy Canyon continues to cause problems in the commingled zones.

Use of a water-control system (incorporating a relative-permeability modification agent as a preflush with fracture treatments) had been considered a viable method for reducing water-to-oil ratios on wells that were once poor candidates for fracture-stimulation because high-water sections of the formation would likely be entered. Reservoirs that were investigated (1) have few or no barriers to help direct and contain fracture growths and (2) extend into both the oil-bearing zones and the high water-content intervals. In the Los Medanos field in southeastern New Mexico, the Brush Canyon formation displayed the problematic conditions and qualifications to satisfy these criteria.

In this field, a typical well is drilled through multiple payzones containing oil/gas deposits and interlying high water-saturation intervals. The Brushy Canyon formation occurs from 7,470 to 7,700 ft below the surface. Water-saturated production intervals are situated above and beneath this region and are separated from it by rather thin, weak intervals composed of shale. Generally, an injection volume of only 100 bbl will penetrate the shale vertically during a fracture-stimulation and enter the water zones. Thin shale intervals are also weaker in stress values than the oil-bearing sandstone. Because a fracture operation in this area's Brushy Canyon formation usually results in a breakthrough into the high water-saturated intervals, the Los Medanos wells were judged to be ideal candidates for the enhanced PCS fracturing job. For a typical stimulation treatment in this formation, perforations are shot within the limits of the oil-producing interval following a limited-entry design at depths ranging from 7,492 to 7,660 ft, so that fracture growth into the water-saturated areas can be curtailed.

PCS treatment design calculations were based on the use of proprietary stimulation programs that consider fluid-loss efficiency and system size in conjunction with the pump rate, relative reservoir stresses, and perforation placement. The treatment was designed so the material would leak off into portions of the created fracture (whether propped or not) before and during the treatment to prevent water production.

During the initial PCS-enhanced treatment in the Los Medanos field, 33 perforations were shot within the central portion of the oil payzone. Linear-gelled spacers (that control the pH levels of the permeability-modification system) were pumped into the wellbore before and after the PCS, so the agent could polymerize at the scheduled time. The preflush and postflush stages were coordinated with respect to the designed leakoff and system placement. The goal was for the modification chemical to be placed through the created fracture into the formation more than half the distance of the total fracturing length. After the PCS was placed in the wellbore, fracturing fluid was pumped down the tubing at a rate of 10 bbl/min with the designed pad and subsequent proppant-laden stages.

The design for the PCS enhancement treatment is developed with a computer fracture-design program that considers variables for placement, leakoff effect, and volumes of the RPM agent. With information such as stress data, bottomhole treating pressure (BHTP), formation closure pressure, Poisson's ratio, coefficients of fluid efficiency, etc., the design technique for placing a fracture treatment is conducted with fracturing models that enable a calculated placement during fracturing. The computer design also manipulates the design process for a preflush that controls pH and leakoff effect ahead of the RPM agent. If the effective fluid efficiency of a gelled preflush is known, and if the preflush is followed by the RPM agent, the size of these stages can be adjusted so that placement is approximately half the length of the subsequent proppant-laden fracturing system. The rate, gel loading of the preflush, amount of fluid-loss agent if needed, and sizes of stages can be adjusted in trial runs until an optimal placement is determined.

Production Comparisons

Production data on typical wells in the Los Medanos field was obtained from daily reports and recorded as 5-day averages (Table 1). The lower portion of the table shows average production figures for four previously fracture-treated offset producers in the Brushy Canyon formation that had undergone conventional fracturing jobs. The numbers are based on production from 55 to 60 days as a daily average.

In Table 2, the post-treatment production levels from the well that received the PCS-enhanced stimulation treatment are compared with levels from the four previous conventionally stimulated offset production wells. On the offset producers, production levels for a 60-day period averaged 50 Mcf/D gas, 63 bbl of oil per day (BOPD), and 90 bbl of water per day (BWPD); the WOR stood at 59%. These production yields are reflected in the lower section of the table. In the upper portion of the table, the post-stimulation production history of the PCS-treated well is indicated in 5-day increments through the first 35 days, then at 60 and 90 days' post-treatment. The numbers indicate that the well treated with the PCS-enhanced treatment demonstrated a dramatic increase in oil and gas production and a significant decrease in water production. The WOR also declined after treatment to substantially better levels, falling to 16% during one period.

Table 3 provides 60-day post-treatment production comparisons for (1) two wells serviced with the PCS, (2) the four previous wells that had been treated with similar stimulation designs but without the modification agent, and (3) a separate well serviced with a conventional design with a premium fluid. In retrospect, results obtained through the PCS-enhanced fracturing procedure were superior to results from the other stimulation procedures. The only major difference between all of the stimulation treatments was the use of the prefracturing PCS-enhanced system. The table also contains 90-day post-treatment readings for the modified design: almost 3 months after the PCS service, oil and gas yields were still stable, water flow continued to abate, and the WOR continued to fall.

Figure 1 plots and compares the oil- and water-production patterns of a conventional stimulation treatment with patterns of a fracturing job that used PCS. Note that the oil yields of the PCS jobs develop a flattened curve and maintain a different decline from the conventionally treated wells. The cumulative production of water and oil after both treatments is plotted in Figure 2. The chart indicates that oil-production levels after the RPM treatment are almost identical to the water-production levels of the conventionally stimulated wells; the converse of water-to-oil levels is also true.

Table 4 shows a 60-day comparison of oil and gas production and WOR for two PCS-enhanced wells and five conventionally treated wells. A supplementary comparison of these figures is found in Figure 3, which also compares water production. Figure 4 is a plot of the job pumping history, taken by automated data acquisition equipment that monitored the treatment.

Economic Impact

Table 5 and Table 6 offer respective cost analyses for a typical conventional completion design with a five-well average and for a PCS-enhanced treatment design with a two-well average. The cost of the enhanced completion is slightly more per well than a conventional design, an average of almost $2,800 per well. However, in the conventionally fractured wells, disposal expenses incurred from continuous and excessively high water production outstripped the cost of the fracturing treatment itself, whereas water disposal expenditures played a more minor role in the PCS-enhanced treated wells because of lower water-production rates. This drop in water production is significant because it substantially increased oil and gas production, significantly impacting revenue. Wells in which the PCS was used as a preflush averaged more than 35,000 bbl of oil and almost 40,000 Mcf of gas during the evaluation period, yielding a revenue total of $760,374. The production totals for conventionally fractured wells were slightly more than 19,000 bbl of oil and 18,000 Mcf of gas, yielding a revenue total of $407,430. Without consideration of minimal cost differences, the differential cost between the two well types was more than $350,000 per well for the first 90 days of production after stimulation.

The 90-day comparison between the PCS-enhanced wells was made following completions because the conventionally treated wells are usually deemed unproductive after 90 days. The conventionally treated wells were averaging 23 Mcf/D gas, 8 BOPD, and 36 BWPD after 90 days of production. The conventionally treated wells were squeezed with cement, and production was moved uphole at this time. The PCS-treated wells (two) are still producing 2 years after completion. One well is making 120 Mcf/D gas, 86 BOPD, and 22 BWPD, with a WOR of 20%, and the other well is making 90 Mcf/D gas, 45 BOPD, and 38 BWPD, with a WOR of 46%. Based on continued revenue from production, an additional total of $3,000,726 was generated from the two PCS-enhanced wells. The cost of squeezing the five conventionally treated wells was $49,830. Therefore, the differential cost-benefit (without consideration of minimal cost differences) is more than $1,490,397 per well for 2 years of production.

Conclusions

On the basis of oil and gas production-enhancement results in the Los Medanos operation, PCS has proved successful as a preflush in fracturing jobs. In the past 2 years, PCS has provided similar results in 14 out of 14 treatments performed on wells in the Permian Basin, in Kansas, and in Argentina. These wells were previously considered nonproductive because of extremely high levels of water saturation.

In addition to being in-situ-generated and inert to most other downhole fluids, PCS apparently creates the effective disproportionate permeability that reduces water production, increases oil and gas production, and consequently, boosts production revenues. This task is accomplished without shearing and without introducing counterproductive risk elements, such as the sealing or plugging of pore throats, to the reservoir.

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Table 1 - Production History of Typical Los Medanos - Brushy Canyon Formation

Days	Mcf/D	BOPD	BWPD	Line Pressure (psi)	WOR (%)
5	61	37	64	40	63
10	80	70	116	80	62
15	55	48	128	70	73
20	71	62	91	200	59
40	39	27	43	180	61
60	29	21	35	60	63
Prior Offset Producers (Four Wells Average)					
Days	**Mcf/D**	**BOPD**	**BWPD**	**Line Pressure (psi)**	**WOR (%)**
60	50	63	90	70	59

Table 2 - Production History of PCS-Enhanced Fractured Wells

Days	Mcf/D	BOPD	BWPD	Line Pressure (psi)	WOR (%)
5	312	401	127	280	24
10	141	147	64	200	30
15	90	100	19	175	16
20	57	120	72	70	38
25	93	173	69	140	29
30	178	142	88	140	38
35	166	114	62	140	35
60	192	93	42	125	31
90	172	89	30	110	25
730	105	66	30	70	33
Prior Offset Producers (Four Wells Average)					
Days	**Mcf/D**	**BOPD**	**BWPD**	**Line Pressure (psi)**	**WOR (%)**
60	50	63	90	70	59

Table 3 - Production History of Los Medanos - Brushy Canyon Formation

Producers Treated with PCS Preflush Enhancement (Two Wells Average)					
Days	**Mcf/D**	**BOPD**	**BWPD**	**Line Pressure (psi)**	**WOR (%)**
60	192	93	42	125	31
90	172	89	30	110	25
730	105	66	30	70	33
Prior Offset Producers (Four Wells Average)					
Days	**Mcf/D**	**BOPD**	**BWPD**	**Line Pressure (psi)**	**WOR (%)**
60	50	63	90	70	59
Offset Producer (Treated with Premium Fluid System)					
Days	**Mcf/D**	**BOPD**	**BWPD**	**Line Pressure (psi)**	**WOR (%)**
60	29	21	35	60	63

Table 4 - Results for 60 Day Comparison (PCS vs. No PCS)

Two PCS-Enhanced Wells vs. Five Conventional-Treated Brushy Canyon Formations		
Oil Production	Increase	65%
Gas Production	Increase	122%
Water / Oil Ratio	Decrease	60 to 40%

Table 5 - Cost of Job Analysis, Original Completion Design

Production Cost		
Fracture-Treatment Cost	$	29,700
Water-Disposal Cost		
(36,486 bbl at $1.00/bbl)		36,486
Total Cost	$	66,186
Production Revenue		
(19,140 bbl oil at $19.50/bbl (90 days production)	$	372,230
(18,000 Mcf at $1.90/Mcf) (90 days production)		34,200
Total Production Revenue (90 days production)	$	407,430

Table 6 - Cost of Job Analysis, PCS Completion Design

Production Cost		
Fracture-Treatment Cost	$	38,100
Water-Disposal Cost		
(30,882 bbl at $1.00/bbl)		30,882
Total Cost	$	68,982
Production Revenue		
(35,100 bbl oil at $19.50/bbl (90 days production)	$	684,450
(39,960 Mcf at $1.90/Mcf) (90 days production)		34,200
Total Production Revenue (90 days production)	$	760,374

Table 6A - Extended Revenue Analysis, PCS Completion Design

Additional Revenues – from additional 730 days of production		
(74,020 bbl at $13/bbl) (730 days/per well)	$	962,260
(113,435 Mcf at $1.85/Mcf) (730 days/per well)		209,855
Water-Disposal Cost		
(21,900 bbl at $1.00/bbl/per well)		-21,900
Production Revenues per well (730 days)	$	1,150,215
Total Benefit (per well – 2 years' production)	$	1,841,607
Differential between PCS vs. Conventional Treatments (2 years/per well)	$	1,500,363

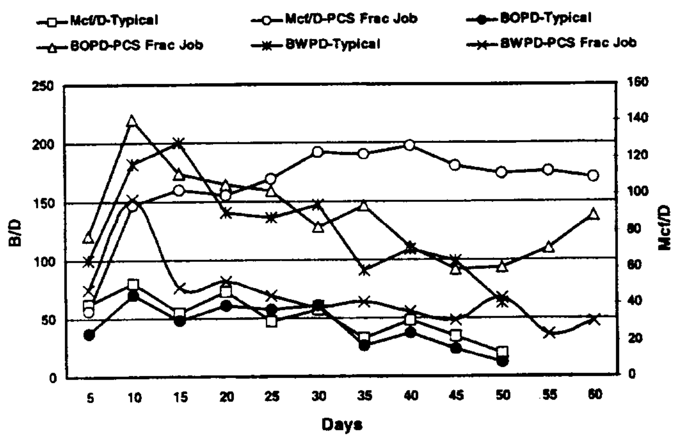

Figure 1 - Daily Production Values for Selected Case Studies

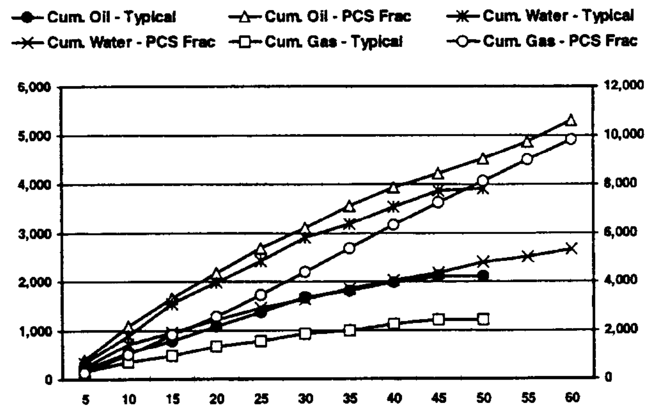

Figure 2 - Cumulative Production Values for Selected Case Studies

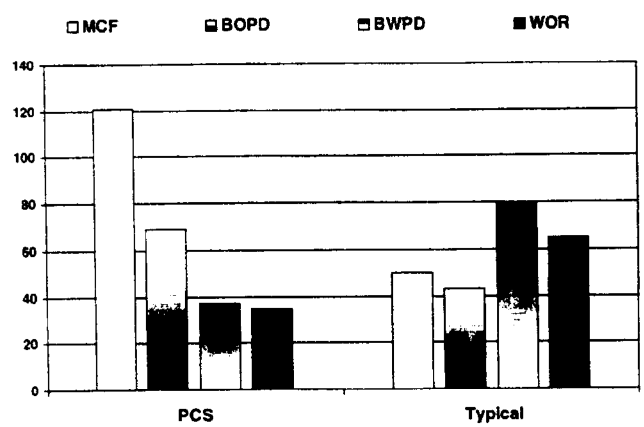

Figure 3 - Comparison of PCS to Typical Fracturing Jobs

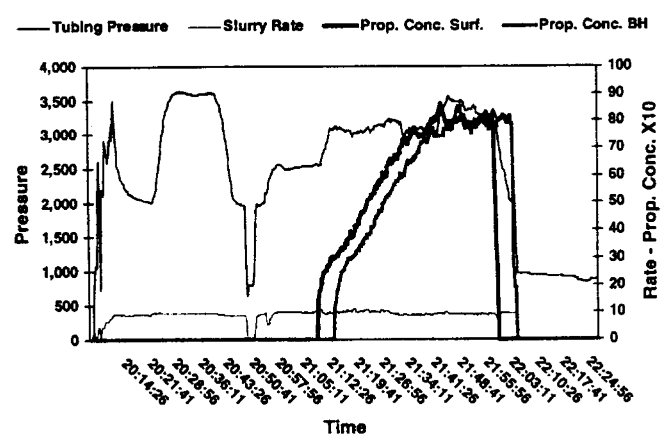

Figure 4 - Time-Comparison of Values for a PCS Fracture Treatment