EVALUATION OF CROSSLINKED ACID GEL IN THE WARREN UNIT OF SOUTHEASTERN NEW MEXICO

Steven Metcalf, Wayne Davis, Daniel H. Gray, Jr. and Brian Ward
BJ Services Company, U.S.A.

Joe Miller and Jeff Brienen
Conoco, Inc.

ABSTRACT

The Warren Unit, located in Southeastern New Mexico produces oil and gas from primarily the Blinebry, Drinkard and Tubb formations. Over the last eight years, many of the Drinkard and some of the Tubb wells in this unit have been fracture acidized to improve production. The main fluid pumped has been a crosslinked acid gel system introduced to the unit to facilitate better leakoff control and, therefore, provide better penetration of the stimulation fluid. The results of these treatments are evaluated. Included are comparisons of other viscous acid treating fluids, proppant laden fluids, a fluid properties discussion, treatment procedure description and well locations in the unit. Lithology differences are discussed to show the limitations of the crosslinked acid gel system.

BACKGROUND

The Warren Unit, located in Lea County, New Mexico, has been developed over the last forty years (Figure 1). Wells in this unit were first drilled in the 1950's and completed in the Drinkard (±6600'), Tubb (±6200') and Blinebry (±5800') formations. The well locations are identified in Figures 2 and 3. The formations were found to be mostly carbonates in nature, specifically dolomite, trending to sandy dolomite. Hydrochloric acid was the natural treating fluid for dissolution of the carbonate portion of the rock to improve conductivity and therefore production. Those wells with a higher sand content were proppant fractured when the acid treatments did not perform as expected. Cumulative production from this unit, through 1994, is 6.1 MMBO and 164 BCF of gas.

During the 1970's several methods of improving fracture stimulation were explored on the Drinkard in the Permian Basin.[1] At the same time various techniques and new acid systems were developed to work on other Permian Basin carbonates.[2,3] These systems were designed to provide better penetration through leak-off control, fracture geometry control and reaction retardation of the hydrochloric acid. It was determined that fracture acidizing was the key to improved production from all carbonates with good solubility. Since the 1970's many papers and books have been written concerning improved acid penetration. In general, leak-off control and retardation are found to be the two most significant parameters in achieving success in vugular and natural fractured dolomites of West Texas and Eastern New Mexico.

The 1980's saw the advent and usage of several crosslinked acid gels in the stimulation of carbonate reservoirs.[4,5] Specifically, the Warren Unit wells began to be stimulated using crosslinked acid gel in place of the viscous acids used in the late 1970's and early 1980's. This paper describes the fluid used and treatment procedures employed. It also reviews the results, since crosslinked acid gel was first introduced in the Warren Unit to stimulate the Drinkard and Tubb formations.

Formation Characteristics

The Drinkard and Tubb are Leonardian age formations. Both formations have oil zones with perceived associated gas caps, in the Warren Unit. [6]

The Drinkard is a shelf carbonate at approximately -3050 feet subsea (±6600 feet). The formation is highly soluble in mineral acids (92.5% soluble in 15% hydrochloric acid). Average formation thickness is 200 feet and can be divided into two zones. The upper zone is a dolomite with limited vugular porosity making it generally non-productive. The lower zone consists of interbedded limestone and dolomite. Production is from natural fractures and vugular porosity. The oil zone has an average porosity of 12% while the associated gas cap has an average porosity of 10%. The Young's Modulus and Poisson's Ratio in the Warren Unit No. B-T#111 were found to be 2.35 to 2.92 x 10^6 psi and 0.335 to 0.395 respectively.[7]

The Tubb is encountered at approximately -2700 feet subsea (±6280 feet) in the Warren Unit. The pay zone is dolomite and sandy dolomite. From 1957 until the mid 1970's only the gas zone of the Tubb was produced. The oil pool has an average net pay thickness of 54 feet. The associated gas cap has a net pay thickness of 28 feet. Porosity ranges from 7 to 18% with an average of 9%.

The Warren Unit No. 8 was the first well to penetrate both horizons and was completed in the Drinkard in 1950. In 1957 the WU No. 8 was recompleted in the Tubb gas pool. Fourteen wells have been completed in the Drinkard and thirty-seven in the Tubb through 1994. The Tubb primarily produces commingled with the Blinebry. Through the end of 1994, 451 MBO and 7836 MMCFG and 5605 MBO and 156503 MMCFG have been recovered from the Drinkard and Blinebry-Tubb respectively.

Treatment Procedures

Warren Unit Wells are multiple zone completions with dual production from the Drinkard and the Blinebry-Tubb. Completion procedures involve not only the major stimulation with acid fracturing or sand fracturing of individual zones but also the evaluation, preparation and breakdown of intervals.

Wells are drilled out to facilitate running of a cement bond log (CBL) from plugged back total depth (PBTD) to the top of cement. The bonding information is used for two defining details of stimulation. First, whether the Drinkard can be stimulated while isolating the productive zone from a known water transition zone. Secondly, the maximum pay thickness that can be perforated and still provide protection from fracture communication between the different productive horizons.

Preparations prior to perforating are important. After drilling out the casing, the wellbore is circulated with clean brine until return fluids are clear. The CBL is run under pressure and the casing is pressure tested to 4500 psi. The workstring is pickled using 500 gallons of 15% hydrochloric acid providing for better control of iron and other materials which can cause contamination of the reservoir. On remedial treatments or recompletions the pickling fluid is 250 gallons xylene and 500 gallons 15% hydrochloric acid. Perforating is performed at one or two shots per foot in 15% hydrochloric acid spotted across the zone.

Prior to the fracture treatment, the Drinkard perforations are usually broken down using either a packer and retrievable bridge plug or a Pin Point Injection (PPI) tool for isolation. 15% hydrochloric acid is used with 1.3 specific gravity ball sealers pumped at 5 barrels per minute (bpm) with a maximum pressure of 6000 psi when a packer and plug are used. The rate is held to 2-3 bpm when using the PPI tool and the 15% hydrochloric acid is used at a 20 to 1 ratio gallons per foot perforated. The Tubb is similarly broken down prior to either an acid fracture treatment or a sand fracture treatment.

Typical sequence of stages for an acid fracture treatment of a Drinkard or a Tubb zone is in Table 1. Treatments are normally pumped at a surface treating pressure under 6000 psi, at a rate of 10 to 25 bpm with 15 bpm being the most common. This equates back to approximately 0.25 bpm per foot of perforated interval. The lead acid of each stage is usually 500 to 1000 gallons of 15% hydrochloric acid with a higher loading of iron reducing and iron sequestering additives. This is done to insure maximum protection against iron precipitation problems. Crosslinked 15% hydrochloric acid gel follows, providing for fracture propagation and etched conductivity. Figures 4 and 5 illustrate typical rate and pressure profiles with time exhibited during an acid fracture treatment of the Drinkard and Tubb respectively.

Flowback is initiated after the crosslinked acid gel has broken, usually after three to four hours (dependent upon bottomhole temperature and breaker loading). The shut-in time should always be minimized, when possible. The broken fluid retains sufficient viscosity to facilitate removal of any fines released by the acid.

Tables 2 and 3 list some of the treatments pumped on the Drinkard and Tubb wells, respectively, in the Warren Unit since 1989 The fluid description column details only fluids and volumes pumped in the main acid fracture treatment. Eighteen of the treatments listed were pumped in multiple stages. The total volume of acid varied from 4500 gallons to 30500 gallons. Treatments using fluids other than crosslinked acid gel were pumped by several service companies.

Fluid Properties

Crosslinked acid gel was developed in the early 1980's.[5] The system is based on a synthetic polymer that does not decompose, even in concentrated hydrochloric acid. Rapid hydration in hydrochloric acid without precipitation was also a design criteria for this polymer. A transition metal ion is used to effect crosslinking of the polymer chains to form the viscoelastic gel. Breaking of the system is accomplished through the use of an coated breaker.

The crosslinked acid gel system typically used in the Warren Unit has a liquid polymer loading of 20 gallons (66 pounds of polymer) per thousand gallons of acid. Rheological profiles of this crosslinked acid gel are illustrated in Figure 6 at shear rates of 40 and 170 reciprocal seconds (sec^{-1}). This data was obtained using a Baroid Fann 50 at 150°F with 15% hydrochloric acid. The fluid, although shear thinning, maintains a viscosity significantly greater than a typical gelled acid. Figure 7 shows the profile of the same fluid with the addition of 20 pounds coated breaker per thousand gallons of fluid. Viscosity reduction upon breaking is more extensive in the presence of carbonates. Static water bath tests with formation material support the Fann 50 observed fluid break data.

The exceptionally high viscosity values attainable with this fluid are responsible for more effective fracture geometries. These improved geometries are attainable with smaller volumes and lower pump rates than typical gelled acid treatments. The viscosity, an important parameter in the control of leak-off, also provides better fluid efficiency.

Crosslinked acid gels are reported to have desirable reaction kinetics.[5] Warren Unit core samples are being evaluated for reaction rate information. However, other Permian Basin dolomite formations have shown these fluids to have marked retardation. Figure 8 demonstrates one such test on a sample of Clearfork dolomite. The change in acid percent is plotted versus time for this sample in both 20% hydrochloric acid neat and crosslinked acid gel.

Friction pressure reduction is always a consideration when fracturing.[5] Minimizing this will assist in reducing hydraulic horsepower requirements and costs. Figure 9 reflects the percent reduction in friction as a function of rate. This fluid will typically demonstrate some reduction in friction above 3 bpm. At rates in excess of 10 bpm, friction reduction becomes asymptotic at about 60% of neat 15% hydrochloric acid.

RESULTS

Field results are listed in Tables 2 and 3 and the wells are marked with arrows in Figures 2 and 3. Production rates reported are 30 to 40 days after load fluids have been recovered.

The majority of treatments in the Blinebry formation (to be covered in a future paper) have been fractured with a proppant laden fluid. Production from the Blinebry and Tubb is downhole commingled, therefore, individual test rates from each are not always available, as noted in Table 3. As mentioned earlier, the Tubb formation on the edge of the field becomes sandier and requires a sand fracture treatment. One Tubb well (WU #106) is listed that was treated with a propped fracture treatment using an organoborate crosslinked guar water based system carrying 16/30 proppant.

Drinkard Wells

All of the Drinkard wells listed in Table 2 were initial completions with the exception of the re-stimulation of the Upper Drinkard in the WU #94. Table 4 lists the cumulative production for all of these wells through 1994. All wells except the WU #98 were stimulated using a crosslinked acid gel. The WU # 95 had a crosslinked acid gel acid fracture treatment on the Lower Drinkard and the Upper Drinkard was acid fractured using a gelled 15% hydrochloric acid and CO_2 combination.

The Warren Unit # 96 Drinkard production curve is shown in Figure 10. Evaluation of the decline rate shows a 10% decline in gas production and nearly a 10% decline in oil production. As can be seen on the map in Figure 2 the well is located in the heart of the unit. The well was acid fraced in a single stage using crosslinked 15% hydrochloric acid gel as the lead fluid to establish the fracture, provide leak-off control for the treatment and allow placement of live acid at the tip of the fracture created. The treatment was pumped at 15 bpm during the 5000 gallons of crosslinked acid gel and 5000 gallons of heated 15% hydrochloric acid. The rate was reduced to 2 bpm during the last 4000 gallons of heated 15% hydrochloric acid. The last two stages of acid were heated to compensate for formation cooling and subsequent retardation near the wellbore of the acid. This was believed to be a problem since the well was to be opened up as soon as the crosslinked acid gel began to break and it was imperative that all the near wellbore acid be spent.

The acid fracture treatment on the Warren Unit #98 resulted in one of the lowest initial production rates. This may be due in part to location in the unit, to the use of gelled acid instead of crosslinked acid gel or both. This well was staged to attempt effectively treating the entire interval (6804' to 6859') using 14000 gallons of total 15% hydrochloric acid. The lead acid used in each stage of this treatment was gelled. This may have not provided a sufficient amount of leakoff control to facilitate adequate penetration of live acid into the formation.

The wells completed in 1994 (WU #111, #112, #113 and #115) were all stimulated with the treatment procedures discussed earlier, except for the use of a new breaker in the crosslinked acid gel system. All the wells showed good tests, with the exception of the WU #115 gas rate. The WU #112 has the second highest gas test since the WU #96 was completed in 1990. The WU #112 and #111 have the highest oil tests of any of the wells reported on in this paper. Previous to 1994 the coated breaker used had functioned extremely well, however improvements in the coating material allowed the introduction of a new breaker that seems to be giving some assistance to higher initial production rates. This breaker is still being evaluated.

Tubb Wells

The Tubb stimulations are listed in Table 3, with individual well cumulative production reported in Table 5. The ten treatments reported can be divided into two categories, re-stimulations (four wells), and new completions (six wells).

Three of the four re-stimulations (WU #9, 30 and 42) used crosslinked acid gel and the fourth (WU #26) used gelled acid. All of the re-stimulations were economically successful. The after treatment rates for the crosslinked acid gel averaged 32 BOPD and 256 MCFD as compared to the gelled acid treatment which tested 33 BOPD and 239 MCFD. All four wells are located on the eastern flank of the structure and are considered to have similar reservoir characteristics.

The Warren Unit #9 production curve is illustrated in Figure 11 and demonstrates the improvement seen typically in re-stimulations with crosslinked acid gel or gelled acid. The oil and gas production were on 30% declines before the treatment and a 15% decline after treatment. This well used the heated tail-in acid mentioned in the section on the Drinkard. Diversion between stages was accomplished using rock salt instead of ball sealers. The initial test after the treatment indicated nearly a doubling of production.

Four of the six new well completions utilized crosslinked acid gel (WU #94, 97, 99 and 110). Of the remaining two wells, one was treated with a sand frac (WU #106) and the other (WU #98) was treated with a special fluid loss control acid. Table 3 summarizes the results and type of treatment pumped.

The after treatment production rates, for the crosslinked acid gel, averaged 96 BOPD and 111 MCFD. This compares to 50 BOPD and 189 MCFD for the sand frac treatment and 28 BOPD and 20 MCFD for the special fluid loss control acid. It should be noted that the four crosslinked acid gel treatments had significantly better structural positions than the other two wells.

Although the WU #97 is an initial completion, it has a before and after test. A pre-frac production rate was recorded after a small 15% hydrochloric acid breakdown.

CONCLUSIONS

Knowledge obtained over the last eight years of stimulation of the Drinkard and Tubb formations of the Warren Unit includes:

1. Initial production rates for new well completions in the Warren Unit's Tubb formation that utilized crosslinked 15% hydrochloric acid gel treatments were higher when compared to sand fracturing and special fluid loss control acid.

2. Re-stimulation candidates in the Warren Unit's Tubb formation appear to have yielded similar results regardless of the type treatment employed.

3. Crosslinked 15% hydrochloric acid gel treatments in the Warren Unit's Drinkard formation provide an economic and effective stimulation.

4. Crosslinked 15% hydrochloric acid gel provides an improvement in retardation of reactivity in vugular and naturally fractured dolomite formations.

5. Proper appraisal of lithology and solubility of the formation must be incorporated into the design to yield the best match-up of fluid and technique for each particular well.

REFERENCES

1. Rose, Kenneth S.: "Brine External Polyemulsion Acid Fracturing in Permian Basin Carbonate Reservoirs," presented at the 25th Annual Southwestern Petroleum Short Course, Lubbock, Tx. April 20-21, 1978 p 111.

2. Church, D. C., Quisenberry, J. L. and Fox, K. B.: "Field Evaluation of Gelled Acid For Carbonate Formations," presented at the 28th Annual Southwestern Petroleum Short Course, Lubbock, Tx. April 23-24, 1981 p 85.

3. Crowe, C. W., Martin, R. C. and Michaelis, A. M.: "Evaluation of Acid Gelling Agents For Use In Well Stimulation," presented at the 28th Annual Southwestern Petroleum Short Course, Lubbock, Tx. April 23-24, 1981 p 93.

4. Pabley, S. Avtar and Holcomb, David L.: "A New Method of Acidizing or Acid Fracturing: Crosslinked Acid Gels," presented at the 27th Annual Southwestern Petroleum Short Course, Lubbock, Tx. April 17-18, 1980 p 31.

5. Deysarkar, A. K., Dawson, J. C., Sedillo, L. P. and Knoll-Davis, S.: "Crosslinked Fracture Acidizing Acid Gel," Paper No. 82-33-16 presented at the 33rd Annual Technical Meeting of the Petroleum Society of CIM, Calgary, Canada, June 6-9, 1982.

6. Becnel, Joe and Fago, Thomas A.: "Warren Unit Lease Evaluation," Conoco, Inc. internal report, January, 1991.

7. DeVine, Carolyn: "Rock Characterization and Formation Sensitivity: Limestone Intervals, Warren Unit B-T #111, Lea County, New Mexico," BJ Services Laboratory Report 94-4-185.

ACKNOWLEDGEMENTS

We wish to express our appreciation to BJ Services, R & D management, for their support and permission to publish this paper. We would like to thank BJ Services, Permian Basin Region and Conoco, Inc. for providing most of the field data.

Table 1	
Acid Frac Stage Sequence	**Fluid Description**
1	15% Hydrochloric Acid + Non-emulsifier + Corrosion Inhibitor + Iron Sequesterant + Iron Reducing Agent + Friction Reducer
2	Crosslinked 15% Hydrochloric Acid + Non-emulsifier + Corrosion Inhibitor + Iron Sequesterant + Crosslinker + Breaker + Gelling Agent
3	15% Hydrochloric Acid + Non-emulsifier + Corrosion Inhibitor + Iron Sequesterant + Friction Reducer + Ball Sealers
4	15% Hydrochloric Acid + Non-emulsifier + Corrosion Inhibitor + Iron Sequesterant + Iron Reducing Agent + Friction Reducer
5	Crosslinked 15% Hydrochloric Acid + Non-emulsifier + Corrosion Inhibitor + Iron Sequesterant + Crosslinker + Breaker + Gelling Agent
6	15% Hydrochloric Acid + Non-emulsifier + Corrosion Inhibitor + Iron Sequesterant + Friction Reducer
7	Completion Fluid

Table 2				
Well No.	**Formation**	**Perforations**	**Fluids Description**	**Results**
94	Drinkard	6713-6677	14000 gals Crosslinked 15% HCl + 6000 gals CO_2 Pumped in Two Stages	45 BOPD, 83 BWPD, 15 MCFD
94	Drinkard	6605-6625	7000 gals Crosslinked 15% HCl + 3000 gals CO_2	50 BOPD, 0 BWPD, 250 MCFD
94	Drinkard	6605-6625	5000 gals Crosslinked 15% HCl	22 BOPD, 12 BWPD, 427 MCFD
95	Drinkard	6690-6792	14000 gals Crosslinked 15% HCl + 6000 gals CO_2 Pumped in Two Stages	22 BOPD, 8 BWPD, 1159 MCFD
95	Drinkard	6590-6618	12000 gals Gelled 15% HCl + 5000 gals CO_2 Pumped on Two Stages	
96	Drinkard	6749-6824	5000 gals Crosslinked 15% HCl + 9000 gals Heated 15% HCl	40 BOPD, 73 BWPD, 2147 MCFD
97	Drinkard	6730-6841	9000 gals Heated 15% HCl + 5000 gals Crosslinked 15% HCl Pumped in Two Stages	10 BOPD, 100 MCFD
98	Drinkard	6804-6859	9000 gals 15% HCl + 5000 gals Gelled 15% HCl Pimped in Two Stages	12 BOPD, 147 BWPD, 53 MCFD
111	Drinkard	6662-6803	3000 gals Heated 15% HCl + 5000 gals Crosslinked 15% HCl + 2000 gals 15% HCl	91 BOPD, 123 BWPD, 1037 MCFD
112	Drinkard	6677-6798	10500 gals 15% HCl + 20000 gals Crosslinked 15% HCl Pumped in Two Stages with 40 Ball Sealers Diversion	76 BOPD, 1700 MCFD
113	Drinkard	6644-6779	10500 gals 15% HCl + 20000 gals Crosslinked 15% HCl Pumped in Two Stages with 51 Ball Sealers Diversion	45 BOPD, 13 BWPD, 300 MCFD
115	Drinkard	6726-6780	5000 gals 15% HCl + 10000 gals Crosslinked 15% HCl Pumped in Two Stages with 24 Ball Sealers Diversion	39 BOPD, 49 MCFD
115	Drinkard	6604-6674	6000 gals 15% HCl + 14000 gals Crosslinked 15% HCl Pumped in Two Stages with 25 Ball Sealers Diversion	

Table 3				
Well No.	**Formation**	**Perforations**	**Fluids Description**	**Results**
9*	Blinebry & Tubb	5871-6647	8000 gals Crosslinked 15% HCl + 2000 gals Heated Gelled 15% HCl Pumped in Two Stages with 1000 pounds Rock Salt Diversion	Before: 15 BOPD, 82 MCFD After: 32 BOPD, 139 MCFD
26	Tubb	6346-6586	15000 gals Gelled 15% HCl + 6000 pounds Rock Salt Pumped in Five Stages	Before: 1 BOPD, 0 BWPD, 390 MCFD After: 33 BOPD, 0 BWPD, 239 MCFD
30*	Tubb	6463-6532	15000 gals 15% Crosslinked HCl + 5000 gals 15% HCl Pumped in Two Stages	50 BOPD, 0 BWPD, 129 MCFD
42*	Tubb	6488-6676	8000 gals Crosslinked 15% HCl + 2000 gals Gelled 15% HCl + 30% CO_2 Pumped in Two Stages with 1000 pounds Rock Salt Diversion	Before: 2 BOPD, 20 MCFD After: 14 BOPD, 500 MCFD
94*	Tubb	6532-6570	500 gals 15% HCl + 3000 gals Crosslinked 15% HCl	11 BOPD, 0 BWPD, 391 MCFD
94*	Tubb	6377-6570	3000 gals 15% HCl + 11000 gals Crosslinked 15% HCl Pumped in Two Stages with 50 Ball Sealers Diversion	
97*	Tubb	6373-6591	16000 gals Crosslinked 15% HCl + 30% CO_2 + 4000 gals Heated(120°F)Gelled 15% HCl + 30% CO_2 Pumped in Two Stages with 100 Ball Sealers Diversion	Before: 14 BOPD, 169 MCFD After: 54 BOPD, 539 MCFD
98	Tubb	6456-6674	16000 gals Special Fluid Loss Control Acid + 4000 gals 15% HCl Pumped in Two Stages	28 BOPD, 25 BWPD, 20 MCFD
99*	Tubb	6412-6553	22000 gals Crosslinked 15% HCl Pumped in Two Stages Treatment Communicated with Blinebry	2 BOPD, 49 BWPD, 1723 MCFD
106*	Tubb	6600-6735	Sand Fraced using 46000 gallons Organoborate Crosslinked Guar + 100700 pounds 16/30	50 BOPD, 132 BWPD, 189 MCFD
110*	Tubb	6392-6593	20000 gals Crosslinked 15% HCl Pumped in Two Stages	315 BOPD, 0 BWPD, 1792 MCFD
*Production Rates Blinebry and Tubb commingled.				

Table 4 Drinkard Completions			
Well No.	Date First Production	Cumulative Gas, MMCF	Cumulative Oil, MBO
94	2/89	809	15.9
95	1/90	1835	3.8
96	11/90	1456	13.7
97	1/92	107	8.0
98	11/91	11	2.7
111	8/94	135	11.3
112	9/94	43	0.7
113	9/94	28	3.7
115	8/94	7	4.3

Table 5 Blinebry-Tubb Completions			
Well No.	Date First Production	Cumulative Gas, MMCF	Cumulative Oil, MBO
97	12/91	521	21.5
98	9/92	46	5.9
99	12/91	770	2.0
110	6/93	767	89.5
All wells Blinebry and Tubb commingled production.			

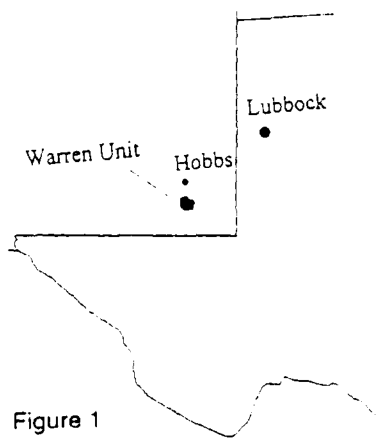

Figure 1

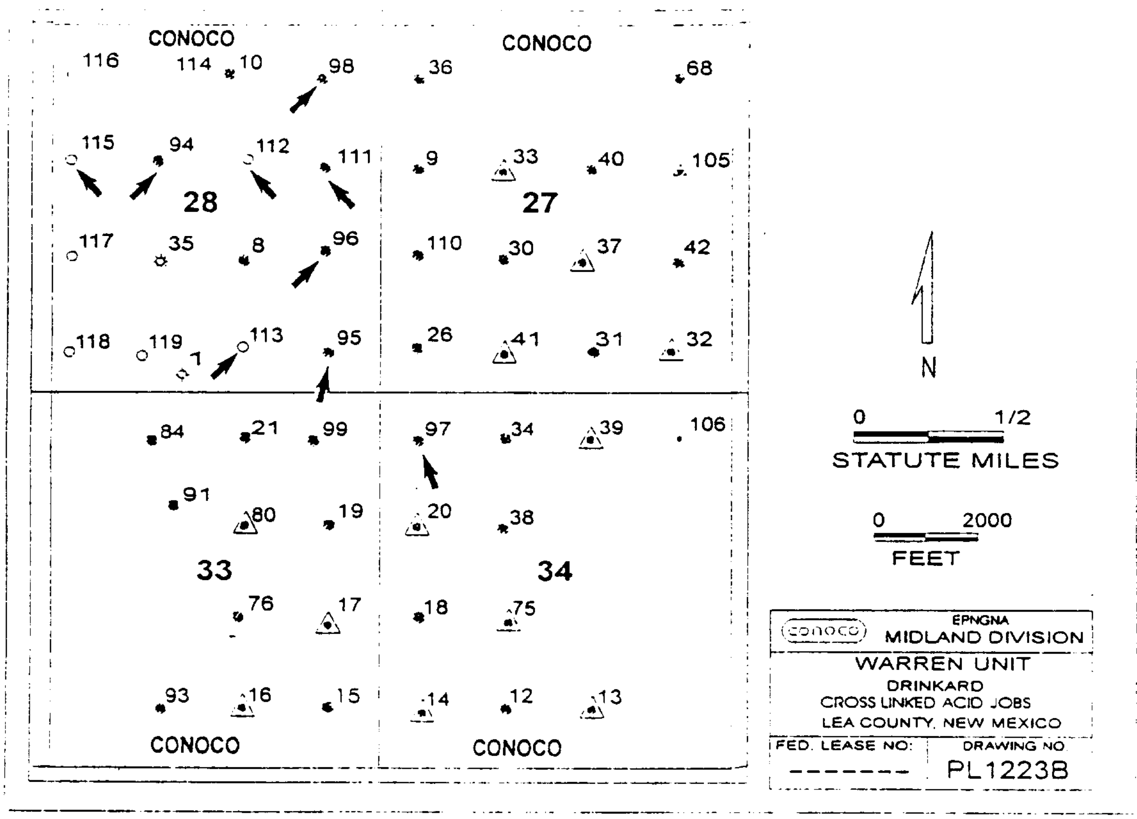

Figure 2

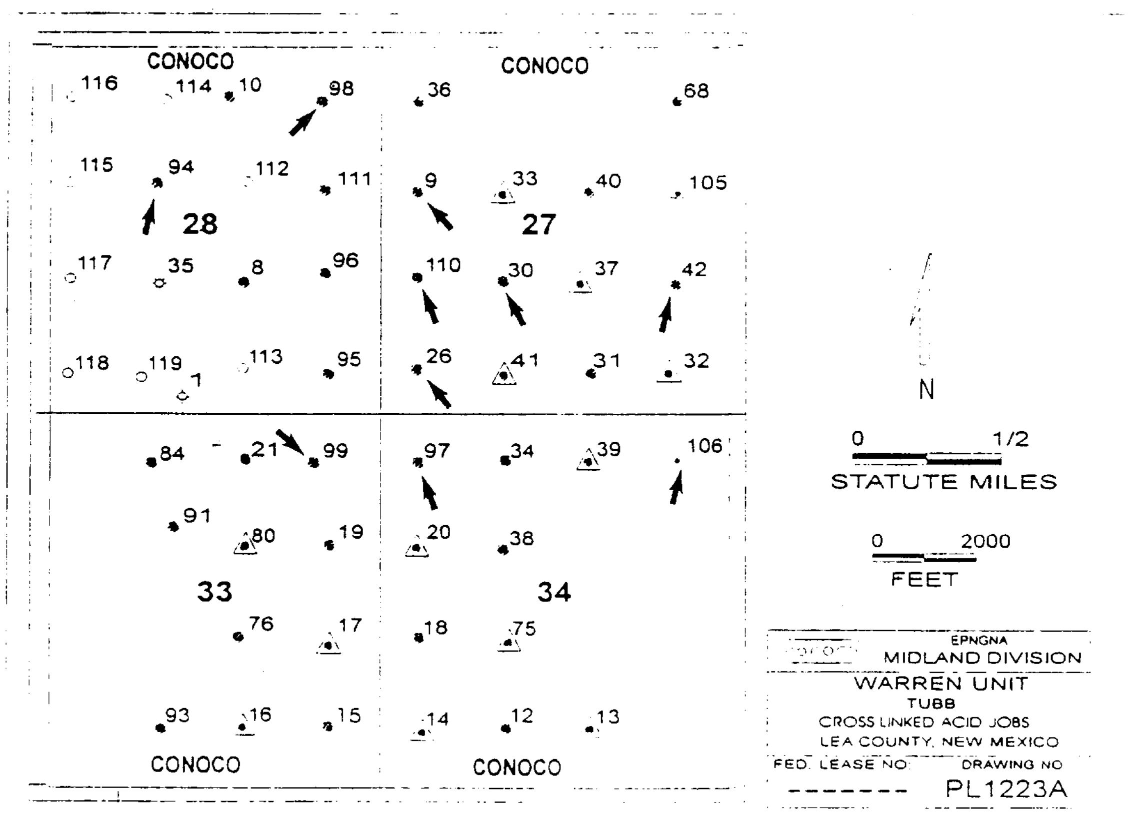

Figure 3

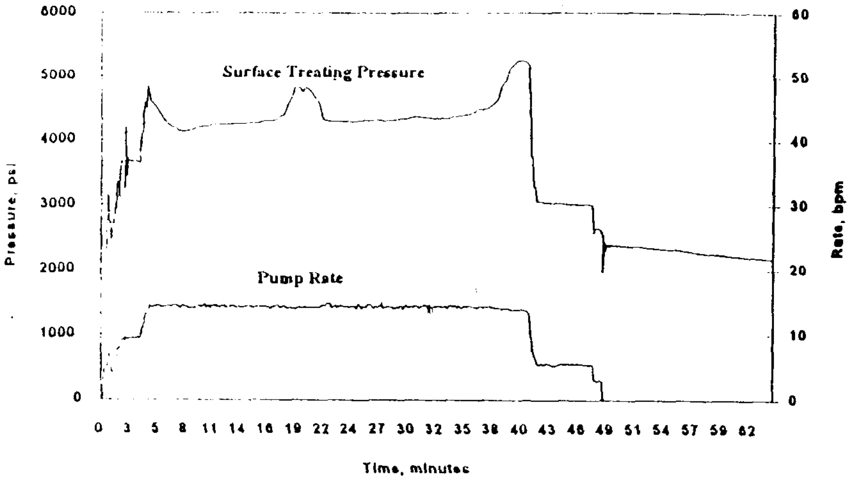

Figure 4 - Warren Unit 115 Upper Drinkard Acid Frac

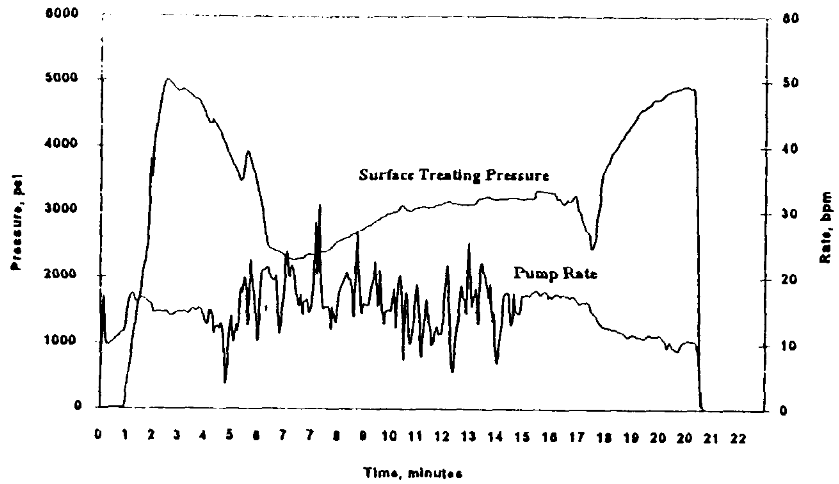

Figure 5 - Warren Unit 94 Upper Tub Acid Frac

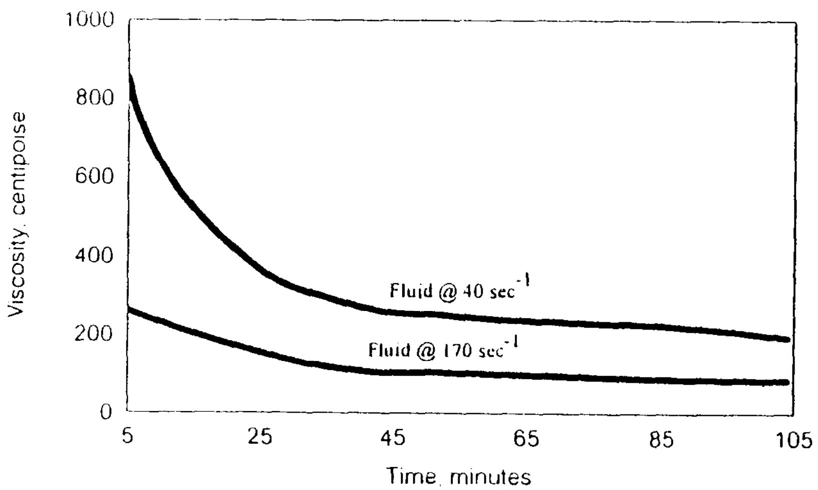

Figure 6 - Crosslinked Acid Gel Viscosity, 150°F

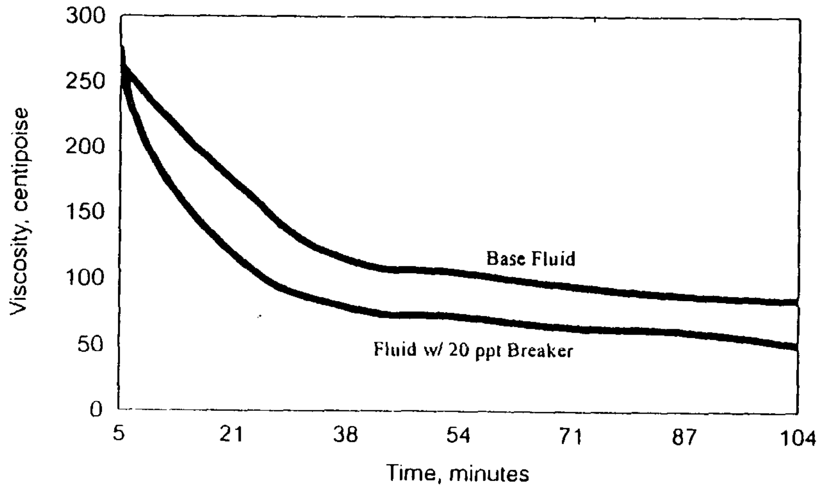

Figure 7 - Crosslinked Acid Gel Viscosity
Effects of Breaker

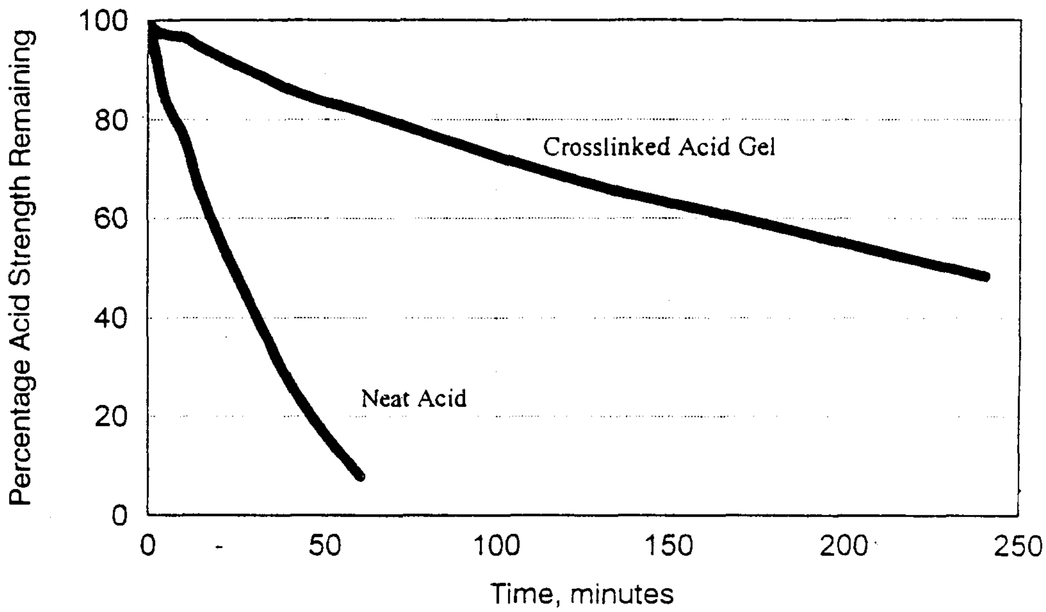

Figure 8 - Crosslinked Acid Gel Reactivity
120°F Clearfork Dolomite

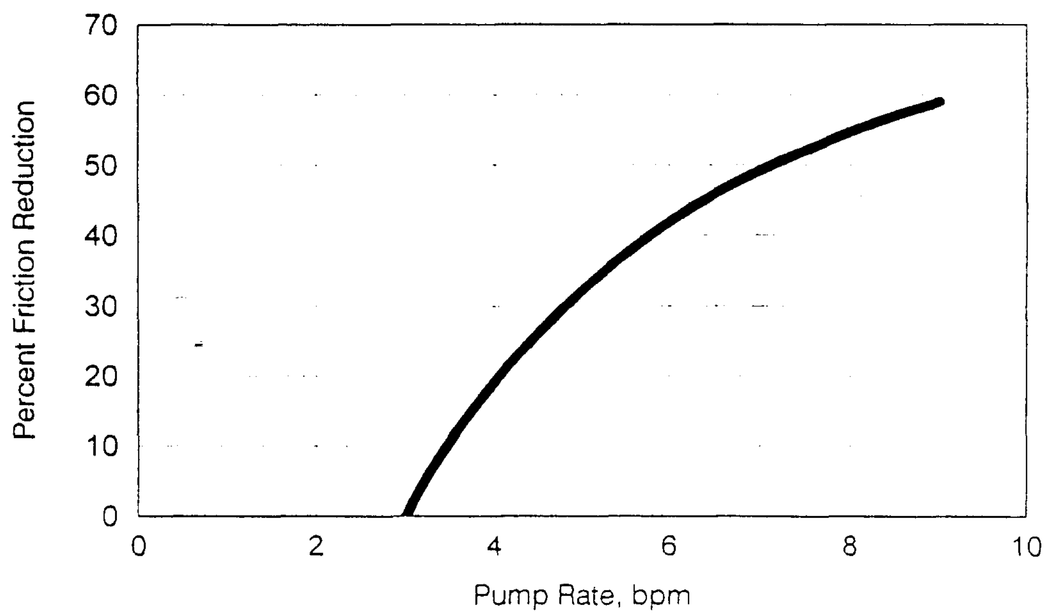

Figure 9 - Friction Reduction Crosslinked Acid Gel

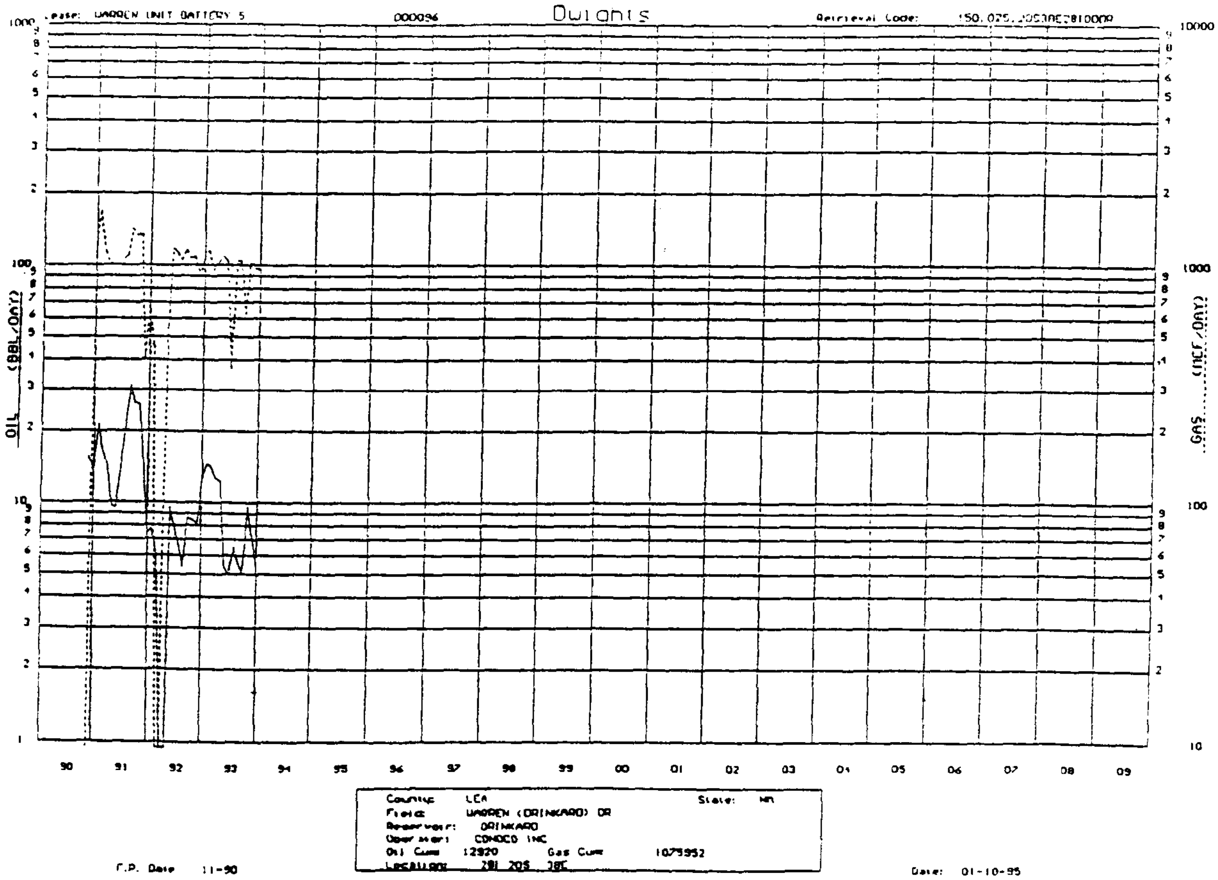

Figure 10

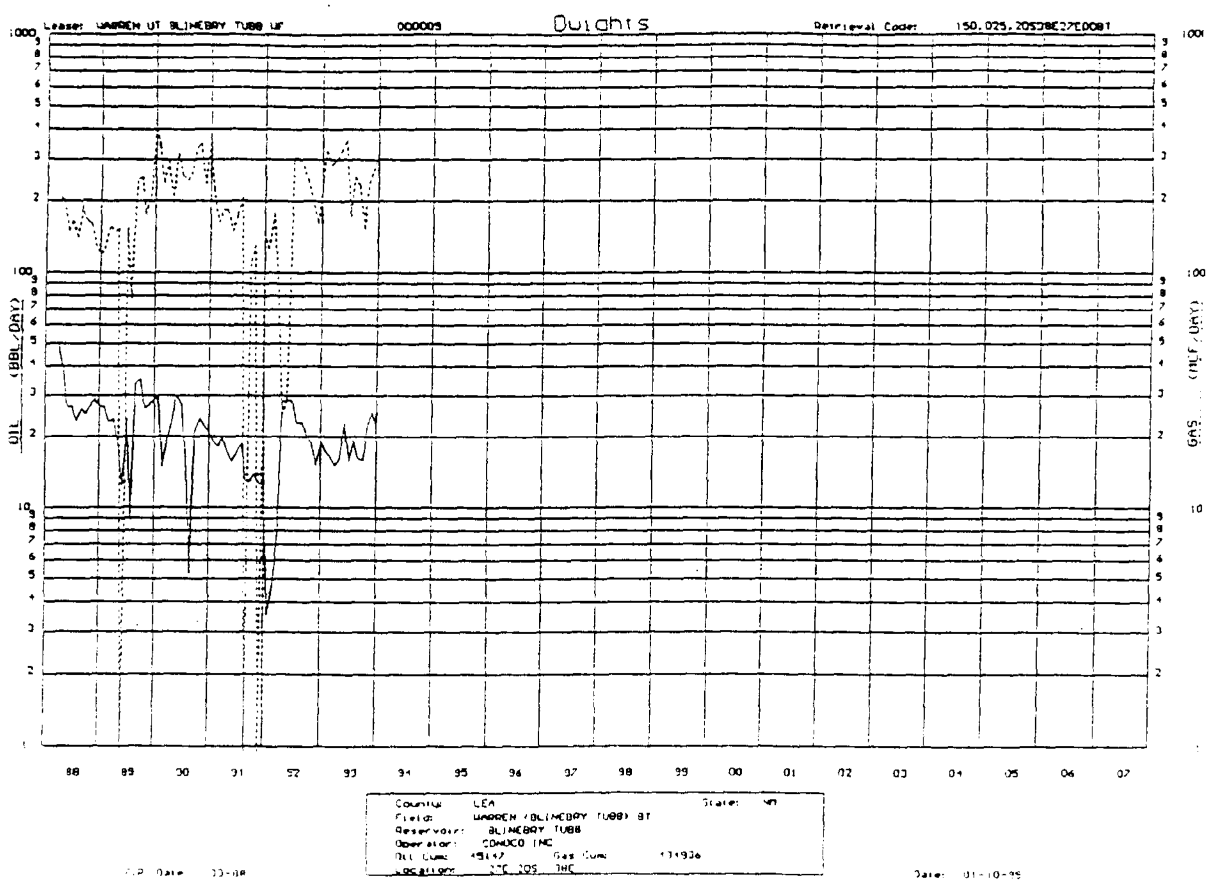

Figure 11