CASE HISTORY OF CO_2 REMEDIAL TREATMENTS: IMPROVED PRODUCTION IN THE WOLFCAMP INTERVALS, VAL VERDE BASIN, WEST TEXAS

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Abstract

Fluid cleanup effects have hampered stimulation success in many tight, naturally fractured sandstone reservoirs. In some cases, cleanup problems affect not only short-term but long-term reservoir deliverability. The Wolfcamp intervals in Val Verde Basin, West Texas are tight, naturally fractured reservoirs and exhibit better responses to CO_2 energized fluids than non-energized fluids.

We will present data from a case study of several wells in the Wolfcamp intervals where 100% CO_2 treatments have increased productivity in both initial and remedial applications. We will discuss how production was increased by 100% CO_2 treatments in wells where non-energized and energized fluids were previously pumped. Then we will discuss treatments where 100% CO_2 was effectively to propagate a fracture and transport proppant. An economic evaluation will be presented on the 100% CO_2 remedial treatments in the Wolfcamp intervals. Finally operational concerns and the equipment set up for 100% CO_2 and CO_2 proppant treatments will be discussed.

Introduction

The three main producing sands in the Wolfcamp are the "A", "C", and "D" sands. The Wolfcamp intervals in the Pakenham Field have been evaluated by many different multi-disciplined teams trying numerous types of treatments with varying results. Initially, the intervals were treated with CO_2 energized fluids and proppant; the treatments were small compared to today's treatment sizes. In mid-1995, the Gas Research Institute's Advanced Stimulation Technology program was used to better optimize the design and placement of treatments.[1] This program used non-energized borate crosslinked fluids during its implementation, and it was successful in placing larger treatments. Later, the treatment fluid choice returned to CO_2 energized fluids. As part of a remedial program in mid-1997, 100% CO_2 pump-in treatments were introduced with favorable results. Based on the results of the 100% CO_2 remedial treatments, we decided to try 100% CO_2 proppant fracture treatments on two wells.

Background - Pakenham (Wolfcamp) Field

The Pakenham field is located in Terrell County, approximately 160 miles south of Midland, Texas **(Fig. 1)**. The Wolfcamp can be subdivided into early Wolfcamp synorogenic and middle Wolfcamp postorogenic deposits **(Fig. 2)**. The early Wolfcamp is represented by the C through F sandstones, shales and detrital limestones. The sandstones are interpreted to be deepwater turbidites deposited as part of a synorogenic wedge into the emerging ValVerde foredeep in front of the advancing Marathon thrust belt. This wedge was later incorporated into the leading edge of the thrust belt **(Fig. 3)**. Production has been established from the upper C and D sandstones.

Porosity ranges from 7 to 11% with air permeability ranging from 0.07 to 4 md. Pore throat radii range from 0.1 to 2.0 microns. Water saturations are 30%. Mineralogically the sands are composed of approximately 85% quartz, 6% clay (predominately illite and chlorite), 5% feldspar and 4% carbonate mostly in the form of rock fragments. Soluble material in 15% HCl is 5%. Natural, open fractures are abundant. Using the technique of Narr[2], average fracture spacing is 3 to 9 ft with average heights of 1 to 3 ft. Fracture azimuth ranges from N10E to N70E depending on the location upon the folded thrust structure. Using borehole breakout and drilling induced fracture data as imaged from formation imaging logs, the present SHmax is N20W **(Fig. 4)**.

The postorogenic middle Wolfcamp sandstones were deposited as deepwater turbidites into the ValVerde foredeep soured from the exposed Marathon thrust belt to the south. Structurally, the middle Wolfcamp is uncomplicated with monoclinal NE dip into the basin. The primary reservoir is the A2 sandstone that pinches out against slope shales.

Porosity ranges from 7 to 11% with air permeability ranging from 0.05 to 0.22 md. Pore throat radii range from 0.1 to 0.6 microns. Water saturations average 40%. Mineralogically the sands are similar to the C and D sands averaging 85% quartz, 9% clay (mostly chlorite and illite), 4% feldspar and 2% carbonate material. Acid soluble material is low at 2 to 4%. Natural open fractures are very abundant. Average fracture spacing is 3.2 ft with an average fracture height of 1.5 ft. They are nearly vertical and consistently strike N60E. Present SHmax is N30W, derived from borehole breakout and drilling induced fracture data **(Fig. 5)**.

Past Treatment History

Initially, the Pakenham field Wolfcamp intervals were treated with 50% CO_2 crosslinked systems. The treatments were pumped at +/- 20 bbl/min via triple entry. Total sand volumes were 80,000 to 120,000 lbm of 20/40 sand with a maximum downhole sand concentration of 6 lbm/gal. Most treatments were tailed-in with 20/40 intermediate strength proppant. At this time, porosity streaks within the entire interval was being selectively perforated using 1 shot per foot (spf).

When Chevron acquired the field in late-1994, the treatments were altered slightly. The fluid choice was still a 50% CO_2 zirconium crosslinked system but the injection rates were increased to +/- 30 bbl/min. The total sand volumes were increased to 250,000 to 300,000 lbm of 20/40 pre-cured resin proppant with a maximum bottomhole sand concentration of 8 lbm/gal. The perforating scheme was also revised, with 1 to 4 porosity lobes being perforated using 2 spf at 90 ° phasing.

In mid-1995, the Gas Research Institute's (GRI's) Advanced Stimulation Technology (AST) program was implemented in the Pakenham field to help improve the design and placement of stimulation treatments.[1] The AST program used non-energized fluids in all intervals and less expensive conventional proppants (i.e., Ottawa Sand) in the A2 to help improve job performance and reduce costs. Point source perforating using a 10 – 20 ft. interval with 4 spf was implemented. The program was very successful in reducing costs and placing proppant in the A2 interval. The application of non-energized fluids did not show widespread improvement in production in the Wolfcamp intervals. The A2 interval had a very wide variance in the results with more non-favorable than favorable results. A decision was made to use energized fluids in the A2 interval going forward. In the D interval only one non-energized treatment was performed. It was pumped as designed and achieved expected production results. There was only one non-energized treatment attempted on the C interval. The treatment screened out on a proppant slug during pad; surprisingly, this is one of the better wells in the field. Due to the complex geology of the C and D sands and the favorable initial responses, it appeared that non-energized fluids would be the proper treatment for these intervals.

Treatment Fluids

Initial treatments used zirconium-crosslinked carboxymethylhydoxypropyl guar (CMHPG)/CO_2 (CO_2/CMHPG/Zr) foams. This type of fluid has been reported to have superior performance in completing low permeability reservoirs.[3,4] In order to minimize fluid related damage, intensive quality control procedures and an aggressive breaker schedules were implemented on both energized and non-energized fluids. Based on laboratory studies we felt that greater than 60% retained conductivity was achieved in the proppant pack with these fluid systems.[5]

Formation damage to the fracture face from the stimulation fluid is generally believed to have a minor impact on well productivity.[6] The A2, C, and D sands have all been identified as being naturally fractured reservoirs and appear to be damaged by fluids.[7] We believe the damage to the natural fractures is the primary reason for poor production results with non-energized fluid systems.

A number of damage mechanisms had to be considered. The most probable included gel damage due to polymeric invasion and relative permeability changes due to foaming agents. In the Pakenham field, polymer damage was believed to be unlikely due to the aggressive breaker philosophy used and the low molecular weights observed in flowback fluids.[8] Laboratory data has shown that completely unbroken borate fluids can form a filter cake;[9] The characteristics of broken zirconium crosslinked fluids have not yet been studied in detail. The reduction in relative permeability from foaming agents may have been another damage mechanism to consider.[10]

We believe that the production responses in the Pakenham field are based on the fluid selection and the presence of natural fractures. One approach to confirm this would be to perform injection/fall-off tests to determine if natural fractures are one influence in the treatment.[11] Based on the results of the injection test an effective fluid and treatment decision may be made.

The 100% CO_2 Pump-in Discovery

The Mitchell 11-8 was perforated in the D interval and had a stable natural production of 800 Mscfd **(Fig. 6)**. Based on this production it was felt that there was presence of a interconnected natural fracture system; it was also felt there may be some removable near-wellbore skin damage. It was determined a foamed nitrified acid treatment should be performed on this interval to remove possible skin damage. The production dropped to 550 Mscfd following the treatment. Pressure transient analysis then indicated that the well had a permeability of 0.3 md and a skin factor of 5.37.

During the evaluation process two, types of remedial treatments were considered — either a 2% KCL water treatment or 100% CO_2. The 2% KCL water injection treatment was chosen in order to obtain more stress and leak off data and remediate any surfactant damage that may have occurred from the foamed nitrified acid treatment. After the 2% KCL water injection treatment, the production dropped to 300 Mscfd. Over the next three months, there was a gradual improvement in production, possibly indicating a water blockage or relative permeability change based on water saturation. The decision was made to pump a 100% CO_2 treatment to see if the well could be remediated following the two fluid treatments. The treatment consisted of 138 tons of CO_2 injected at 25 bbl/min. Then the well was shut in for two days. Flow-back began and the well was flowed to atmosphere until the CO_2 content was less then 10% and returned to the gathering system. Initial production was 1.4 MMscfd and declined to 700 Mscfd. Based on production numbers, we felt we had returned the well to its post-perforated condition. These exciting results prompted us to design other 100% CO_2 remedial pump-in treatments and two 100% CO_2 proppant fracture treatments.

100% CO_2 Pump-in Treatments and Results

Operationally the 100% CO_2 pump-in treatments did not require any changes in the existing wellbore configurations using the tubulars that were in place. The two types of wellbore configurations were 2 3/8" tubing with or without a packer. The treatments pumped down the tubing were treated at rates of 7 to 8 bbl/min and surface pressures of approximately 6,000 psi. The treatments pumped down the annulus were at rates of 20 to 25 bbl/min with surface pressures of approximately 5, 000 psi. All of the treatments were designed with 140 tons of CO_2, which included flush volume. The design volume of 140 tons of CO_2 was selected to equal two-thirds the volume of an average A2 sand frac. Following the treatments, the wells were shut in for 2 days and then flowed back until the CO_2 content was less than 10%. The flowback period averaged 1.5 days and then the wells were returned to production. To date we have performed 7 of these 100% CO_2 pump-in treatments. These treatments were performed with conventional equipment and standard CO_2 cool down and safety practices.

100% CO_2 Sand Fracture Treatments

Based on the encouraging results we had seen on the Mitchell 11-8 and other 100% CO_2 pump-in treatments, we felt we had two candidates for 100% CO_2 sand fracture treatments. The two candidates were the Mitchell 11-8, which we stimulated with a 100% CO_2 pump-in and the Mitchell 31-3 which had not yet been perforated. Both of the intervals to be treated were in the D sand interval. Once the decision was made to treat these wells, great care was made not to introduce any completion fluids to formation at any time. Therefore, the Mitchell 31-3 was broken down with 60 tons of CO_2 after perforating. If tubing was present, a snubbing unit was used to remove the tubing. A snubbing unit or a wireline set packer and plug was to be used following the fracture treatment in order to run the tubing in the hole.

The initial treatment designs on both wells were the same. Pump rates were designed at 50 bbl/min down 5 1/2" casing using 40,000 gallons of CO_2 to place 47,000 lbm of 30/60 intermediate strength proppant **(Table 1)**. The Mitchell 11-8 initially treated as predicted with a rate of 48 bbl/min and surface pressure of 5,600 psi **(Fig. 7)**. When the 1 lbm/gal stage reached formation the bottom-hole pressure started to increase. We were able to pump all of the 1 lbm/gal stage but approximately 2,000 lbm into the 2 lbm/gal stage, we reached maximum surface pressure and had to shut down. An estimated 14,000 lbm of the 47,000 lbm of proppant was placed in formation **(Table 2)**. Utilizing a lumped 3D simulator, we estimated an approximate 40 ft fracture length was generated. Although we did not place the full amount of proppant for which we had designed, the Mitchell 11-8 had an initial production rate of 1.2 MMscfd and is currently producing at 1.0 MMscfd. Based on the Mitchell 11-8 treatment response, we decided to lower our initial sand concentrations to 0.5 lbm/gal on the Mitchell 31-3. Because of pump packing failures during cool-down, we were unable to achieve our desired rate on pad. Our initial injection rate was 37 bbl/min, which was lower then the 50 bbl/min designed rate **(Fig. 8)**. When the 0.5 lbm/gal proppant stage reached formation the bottomhole pressure started to increase rapidly; we pressured out when the 1 lbm/gal stage reached formation. An estimated 7,600 lbm of proppant was placed in formation **(Table 3)**. Based on the large amount of proppant production during flow-back and the poor production response, we feel that the majority of the proppant was produced back during flow back or the concentration and length was inadequate. The well is currently making 0.4 MMscfd. We are currently considering another stimulation treatment on this well.

In order to pump these treatments special considerations had to be made as to the equipment and practices to be used. These treatments require a special blender, mobilized from the Northeast **(Fig. 9)**. The blender requires a constant nitrogen pressure blanket to feed the CO_2 and proppant to the pumping equipment. Conventional nitrogen equipment may be used but it is recommended to use a tube trailer with a pressure regulator.[12,13] Conventional pump trucks and iron are used on these treatments but the cool down procedures do vary from normal CO_2 work. In order to get the CO_2 to its maximum viscosity, the pressure in the vessels are lower to 200 psi which lowers the CO_2 temperature to approximately –20 ° F. In order to prevent thermal failures in the metal, the pumps and iron must be sufficiently cooled down. The pumps are vented to atmosphere until they are approximately 75% cooled down and then a valve is opened on top of the well head to cool down the iron to the well. Due to the larger amount of metal in the pumps, it takes them much longer to cool down then the surface iron. During this process the vent valves on the pumps and well head are pinched back to minimize the amount of CO_2 used. The two wells we treated in the Pakenham field took approximately 1 to 1.5 hrs to cool down and required only using 30 tons of CO_2 per well.

100% CO_2 Pump-in Treatment Economics

The Mitchell 1B-14 has been excluded from this pay-out analysis because of the lowered treatment rates used and volumes pumped due to debris covering the perforations. The average cost of the treatments was $22,222 and the overall average time to pay out was 67 days **(Table 4)**. Base production was calculated by fitting a linear decline to the existing production prior to the pump-in treatments. Incremental production was calculated by subtracting the base from the total. The operator is quite pleased with the results and will continue to perform these types of treatments.

Conclusions

1. The 100% CO_2 pump-in treatments were a success and each well will have a favorable payout with individual, incremental production.

2. CO_2 energized fluids will continue to be the primary choice for stimulation and remedial treatments in the Pakenham field.

3. In naturally fractured, tight-gas sands, it is imperative to know the impact and influences the natural fractures may have on production in order to drill and complete the zone successfully and at full potential.

4. Other tight gas sands that exhibit fluid sensitivity problems may benefit from CO_2 pump-in treatments.

5. When abundant interconnected natural fractures are close proximity of the wellbore, lower sand concentrations and amounts placed in non-damaging fluids may be sufficient to successfully stimulate the well.

6. 100% CO_2 treatments have provided us a means of evaluating the formation for fluid sensitivity problems and provided alternative treatment designs.

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Table 1
Treatment Design, 100% CO2 Frac Jobs, Mitchell 11-8 & 31-3 Leases, D Sand

Stage	Rate (bbl/min)	Stage (gal)	Stage Prop (lbm)	Total Prop (lbm)
Pad	50	12500	0	0
1 ppg	50	10500	10500	10500
2 ppg	50	10500	21000	31500
2.5 ppg	50	6500	16250	47750

Table 2
Actual Job,100% CO2 Proppant-Laden Frac Job, Mitchell 11-8, D Sand

Stage	Rate (bbl/min)	Stage (gal)	Stage Prop (lbm)	Total Prop (lbm)
Pad	48	12300	0	0
1 ppg	45	10350	10350	10350
2 ppg	44	2075	4150	14500

Table 3
Actual Job, 100% CO2 Proppant-Laden Frac Job, Mitchell 31-3, D Sand

Stage	Rate (bbl/min)	Stage (gal)	Stage Prop (lbm)	Total Prop (lbm)
Pad	42	13000	0	0
1/2 ppg	36	9150	4575	4575
1 ppg	30	3030	3030	7605

Table 4
Cost and Economic Benefits of 100% CO2, Pump-in Treatments

Date	Lease Name	Well Number	Zone	CO2 (tons)	Cost ($)	Days to Pay-Out
7/8/97	Mitchell 1B	14	A2	80	17995	210
7/8/97	Mitchell 11	3	D	128	19855	184
7/8/97	Mitchell 1C	5	A2	134	20864	80
9/16/97	Mitchell 11	2	D	143	19995	42
5/27/97	Mitchell 11	4	C	106	20490	39
7/29/97	Mitchell 1B	10	A2	127	23205	31
5/6/97	Mitchell 11	8	D	130	28925	25
	Average**				22,222	67

Date	Lease Name	Well Number	30-Day Incremental		60-Day Incremental		90-Day Incremental		To-Date Incremental		
			Gas (Mscf)	Net ($)	Gas (Mscf)	Net ($)	Gas (Mscf)	Net ($)	Days	Gas (Mscf)	Net ($)
7/8/97	Mitchell 1B	14	2504	$ 5,634	3403	$ 7,657	4474	$ 10,067	128	6364	$ 14,320
7/8/97	Mitchell 11	3	2576	$ 5,796	3171	$ 7,134	5399	$ 12,149	148	7037	$ 15,832
7/8/97	Mitchell 1C	5	5026	$ 11,308	7961	$ 17,911	10494	$ 23,611	149	15214	$ 34,232
9/16/97	Mitchell 11	2	7714	$ 17,357	11700	$ 26,325		0	78	13856	$ 31,176
5/27/97	Mitchell 11	4	7981	$ 17,957	13548	$ 30,482	19152	$ 43,092	123	24334	$ 54,751
7/29/97	Mitchell 1B	10	10578	$ 23,801	15997	$ 35,993	20733	$ 46,650	125	25683	$ 57,787
5/6/97	Mitchell 11	8	15357	$ 34,553	25972	$ 58,437	36906	$ 83,038	159	61516	$138,411

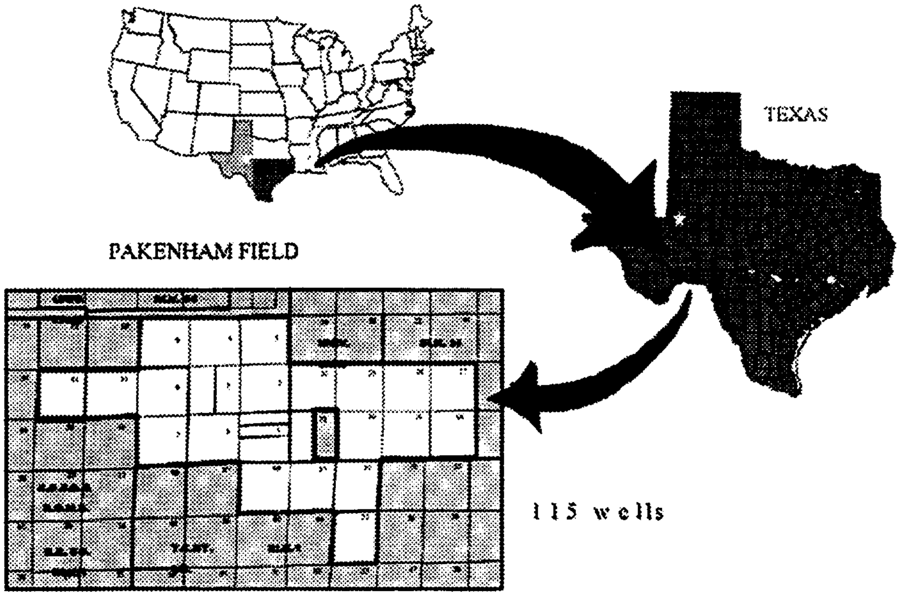

Figure 1 - Pakenham Field Location

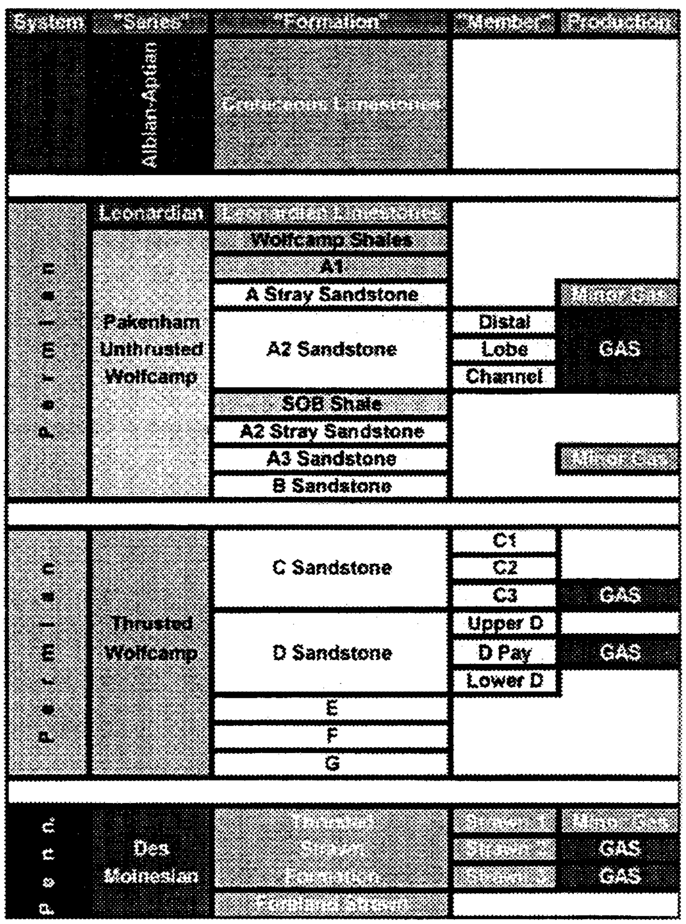

Figure 2 - Stratigraphic Chart, Pakenham Field

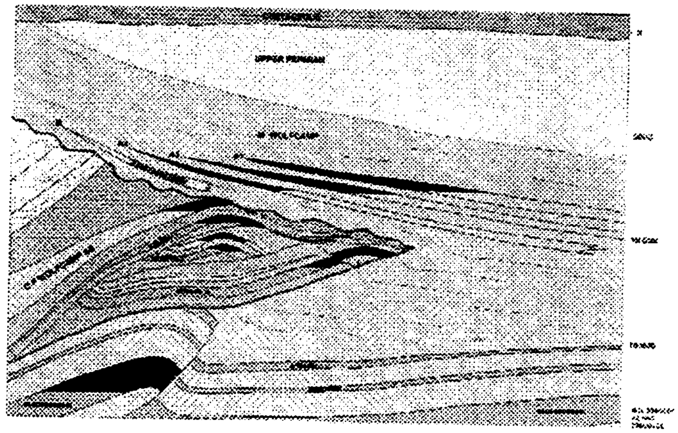

Figure 3 - Pakenham Dip. Structural Cross-Section

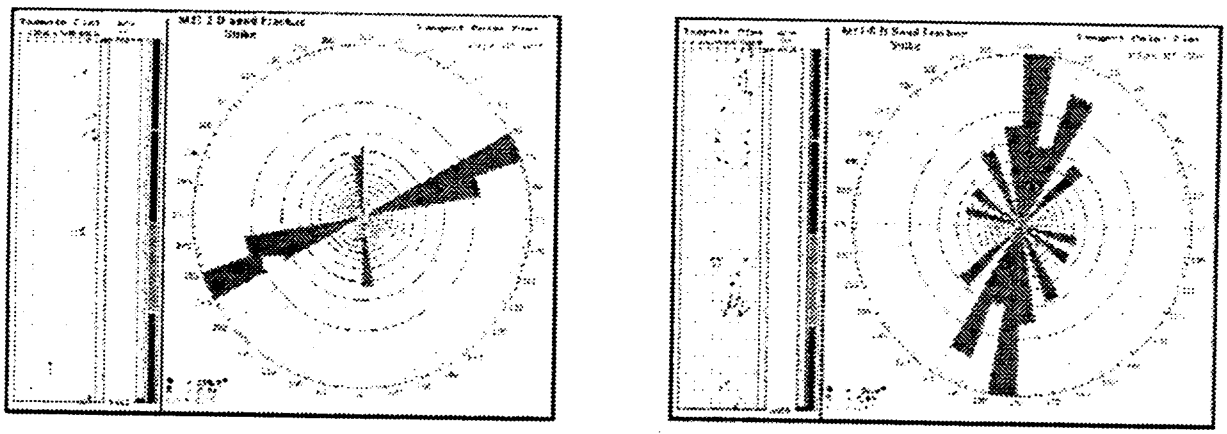

Figure 4 - Maximum Stress Direction and Open Fracture Strikes, Wolfcamp D Sands

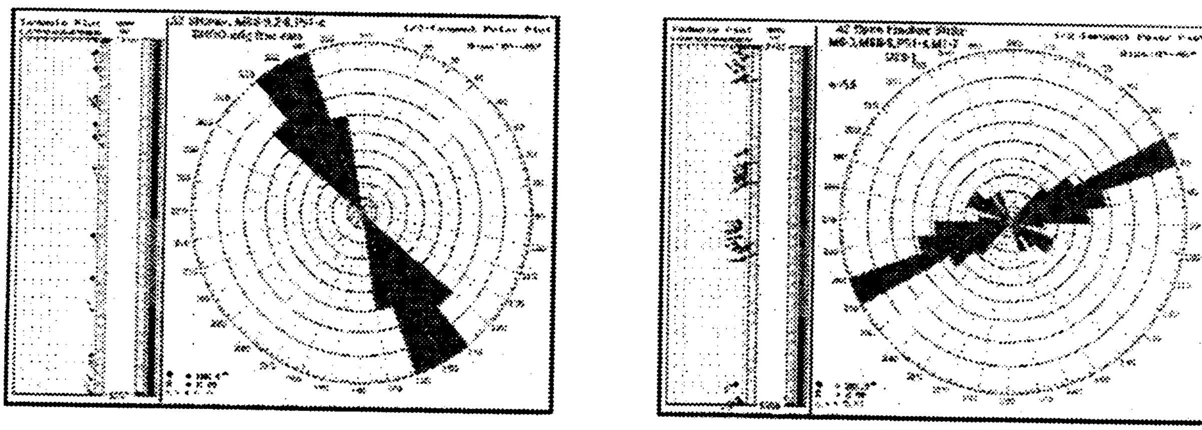

Figure 5 - Maximum Stress Direction and Open Fracture Strikes, Wolfcamp A2 Sands

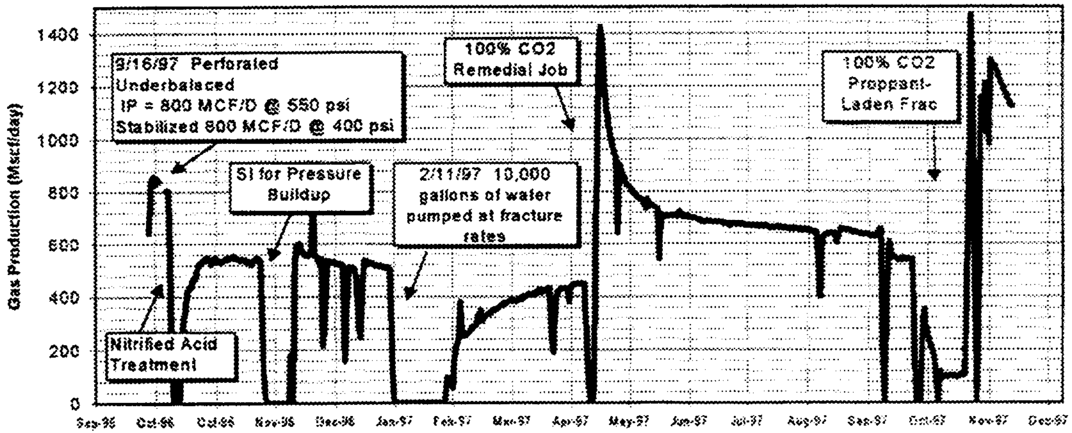

Figure 6 - Production History, Mitchell 11-8 Lease, D Sand

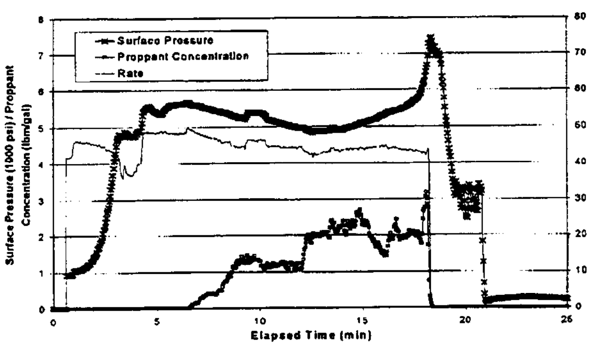

Figure 7 - Mitchell 11-8, 100% CO2 Proppant Fracture Treatment

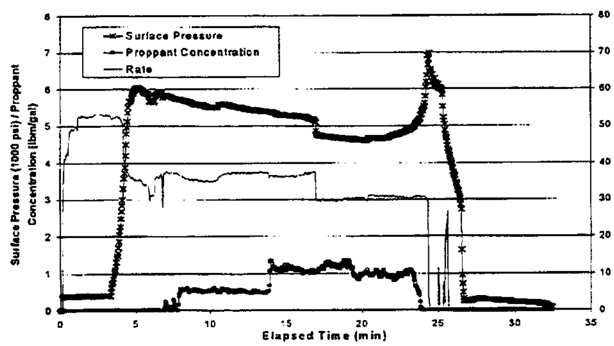

Figure 8 - Mitchell 31-3, 100% CO2 Proppant Fracture Treatment

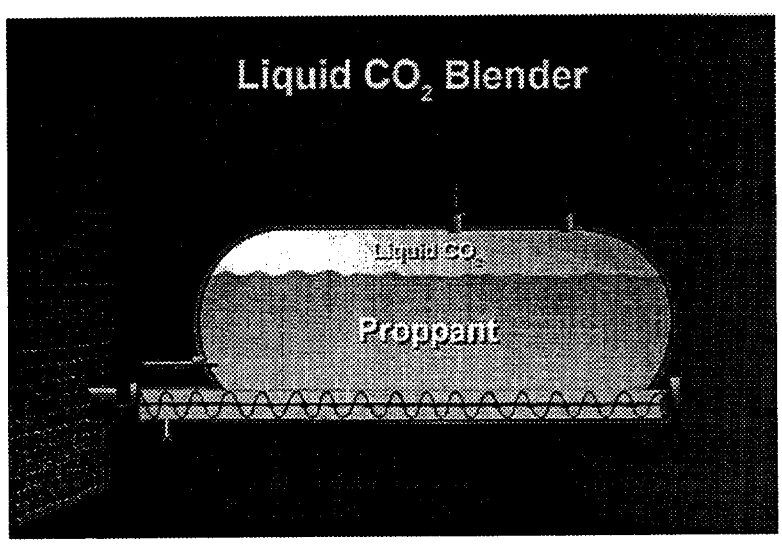

Figure 9 - 100% CO2 Proppant Blender