WEST TEXAS SAN ANDRES SAND FRACS

Ross Rucker
Schlumberger Dowell

ABSTRACT

The San Andres formation in the North Permian Basin in West Texas typically requires stimulation to be economically productive. Acid fracs are effective at increasing production but require frequent repetition due to steep declines. In the past, a comparitively small number of wells were sand-fraced and had limited success. The nature and degree of stresses in and bounding the productive zone typically result in frac treatments growing vertically into high mobility water zones.

Techniques such as plugging back existing perforations and controlled fluid viscosity and pump rates combined with DataFRACs allowed the 35 wells covered in this paper to be fraced with controlled dimensions. This prevented the fracs from growing into adjacent water zones. The subject wells which were sand-fraced since 1993 increased from an average production rate of 12.7 bopd to 35 bopd with an average 28.8% decline. The average water production increased from 25 to 50 bwpd which represents only a 2-fold increase in water compared to a 3-fold increase in oil production.

BACKGROUND

The San Andres formation is part of the Permian system and the Guadalupe Series of the Central Basin Platform, Northwest Shelf and the Midland Basin. It was formed at the same time as the Delaware formation of the Delaware Basin. The lithology consists entirely of a dense dolomite in both Texas and New Mexico. The depth ranges from 4,000 ft to 5,500 ft and the gross interval varies from 5 to 400+ ft. Permeability varies from 0.1md to 10 md.

The San Andres has been produced successfully since the mid to late 1930's. The bulk of San Andres production is from unitized pools that are in mature secondary or early tertiary recovery. The wells discussed in this paper are located in Hockley County (Unit A), Cochran County (Unit B) and Yoakum County (Unit C). These are all in unitized water floods (Figure 1).

UNIT A

Unit A contains several areas which are adjacent to one another, in the Northwest end of Hockley County. The wells produce from an average depth of 4650 to 4800 feet. The areas commenced on waterflood in the early to mid 1980's. They are on an 18 acre linedrive waterflood with one unit containing 79 producing wells and 70 injectors, and the other having 46 producers and 32 injectors.

UNIT B

Unit B is located on the western edge of the Wasson Field in Yoakum County west of Denver City, Texas. This unit produces at an average depth of 5100 feet. The field was discovered in 1936 with a primary production mechanism of solution gas drive. The Unit was formed in 1965 and covers 13,655 acres of which 11,920 acres are currently productive. 118 injectors support 145 producers in the waterflood. The formation is an anhydritic dolomite with an average gross thickness of 200 feet, 40% of that considered productive.

UNIT C

Unit C, located in Southeast Cochran County, covers a portion of the Levelland Field and continues into the northwest part of the Slaughter Field. This field was discovered in 1938 and the Unit was formed in 1942. This Unit produces out of the San Andres at an average depth of 4900-5100 feet. Currently 78 wells are producing, supported by 83 injection wells.

FRACTURE OPTIMIZATION

All of the areas studied represent San Andres production typical to the North Permian Basin. The wells are steady producers with long term prospects. However, the rate of return for an aggressive operator is marginal at best. Stimulation treatments provide a means of artificially accelerating the depletion of the reservoir, thus, increasing rate of return. Acidizing the formation is an almost fool-proof avenue to this end. However, acidizing seldom results in long-term production increases. This is due to the nature of acid fractures, which are typically short (50-100') with high conductivity. This fracture recipe combined with a low permeability (matrix) reservoir usually results in acceptable flush production but high declines.

A propped fracture will generally provide a much longer (100-500'+) fracture, albeit with lower conductivity. This is due to the non-reactive nature of the fluids used. This longer fracture provides a longer linear/bi-linear flow regime, and higher production rates in the pseudo-radial regime. This method is essentially providing a larger wellbore (areal exposure) to the reservoir. Pitfalls in propped fracturing vs. acid fracturing are comparitively larger fracture heights and occasional operational failures (pre-mature screenouts).

As in other oil-field operations, increased radial stimulation penetration also represents increased cost. This increased cost in usually exponential due to the exponential increase in materials required. A rigorous method to optimize the degree of stimulation must be based on the expected production results of the treatment. For this to be done correctly, a good knowledge of reservoir properties is essental.

A type-curve based analysis method was used to determine the optimum fracture properties for the given formation properties. A range of several values was used to sensitize production in order to optimize the frac treatment. Figure 2 shows a sensitivity of production vs. generated in-situ proppant concentration. The optimum falls between 1 and 2 lb/ft^2. This curve was generated using conductivity data from 16/30 mesh Hickory sand assuming a specific fluid damage factor. Proppants with different permeabilities will yield different results.

Figure 3 shows simulated production rate vs. generated fracture half-length. The optimum fracture half-length is 500 feet +. Because of the nature of the stresses in the formation, a half-length of this magnitude was deemed impractical. A fracture half-length of 200 feet was chosen and progressively increased.

A method for placing artificial upper/lower fracture barriers is being used successfully in the Delaware formation in the Delaware Basin in New Mexico. This method involves pumping a low viscosity fluid with various specific gravity proppants into the formation. The pump rate is then decreased to allow the propant to segretate to the top and/or bottom of the fracture. In this manner, a stress barrier is created, thus allowing longer fracture half-lengths to be achieved with controlled frac height. This would be ideal for the San Andres formation and is scheduled for trial in the near future.

Another consideration is retained fracture conductivity. It is well documented that fracturing fluids are damaging to conductivity in varying degrees. The San Andres formation is relatively cool (+/- 100 deg F), which compounds the clean-up of fracturing fluids after the frac treatment. Fluid breakers must be designed to achieve maximum conductivity retention without hindering placement of proppant.

A combination of active and encapsulated breakers were used to maximize conductivity. This breaker combination coupled with 'treatment-specific' addition schedules kept conductivity loss to a minimum, without hindering completion of the treatment.

FRACTURE DESIGN CONSIDERATIONS

The North Permian Basin San Andres formation typically has little formation stress differential for hundreds of feet adjacent to the pay zone. This is substantiated by past fracture stimulation treatments which result in very high water cuts. The fractures tend to grow in a radial manner with the lower portion of the frac extending into the oil/water contact. Not only is this undesirable, it is also very difficult if not impossible to remedy without harming fracture conductivity.

In order to be successful it is necessary to design a fracture treatment with the formation stresses in mind to prevent extension into the o/w contact. With no calibrated stress-data available, this should be done assuming a worst case radial geometry. Initiating the fracture high in the pay zone will assist in preventing extension into the water zone. Theoretically the fracture will extend radially up and down from this point of initiation. An interval of +/-10 feet perforated has shown to be sufficient to frac successfully. In this case, a perforation density of 2 to 4 shots/foot was recommended with a 90 degree phasing. This reduced the near wellbore tortuosity evident in many of the fracture treatments. Figure 4 shows a sandfrac with several shutdowns during the pad. Figure 5 shows the deadstring pressure and the associated pressure drop due to tortuosity.

Limiting perf height is a good way to 'control' frac height growth, but all of the wells in this study had existing perforations, and few of the perforated intervals met the required placement criteria. In this case it became necessary to limit the open-perf interval temporarily for the fracture treatment. Several options were considered, but the option of choice was to plug back all but 10 feet of the existing perforations with pea gravel. After the well was fraced, the pea gravel was reverse circulated out. On one well 20/40 mesh sand was used for plugging back, but the sand was displaced into the formation during the fracture treatment, prompting the use of pea gravel.

Another important aspect is the fracture pump rate. It was originally thought that pump rates in excess of 20 bpm were required to adequately transport proppant at the designed concentrations of 10 ppa. However, this rate was decidedly too high to give confidence to limited height growth. Eventually, 10 bpm was chosen as a good medium and proppant placed successfully on most wells.

In the Units B and C, a water-based borate crosslinked guar was chosen as the fracture fluid because of its' superior proppant transport, wider frac widths (higher in-situ prop concentrations), and high retained prop pack conductivity (utilizing encapsulated breaker technology). In Unit A, a linear water-based guar fluid was chosen for the added comfort of lower viscosity, thus lower generated net pressures and fracture heights. This decision was prompted by the very high failure rate of past fracture treatments due to watering out. Also, the pump rate was lowered to 7 bpm on these wells.

DATAFRACS

It was very important to start the frac programs in each field with successes. This could only be done by pinpointing fracture properties as early in the program as possible. Datafracs were a necessity to determine fracture height and fluid leakoff and to validate Young's Modulus. This was accomplished by determining closure pressure and matching net pressure with a 2D model. A 2D model was deemed sufficient due to the lack of stress data. however, a pseudo-3D model (Fracpro) was helpful to determine other properties quickly in the field. The determination of these frac properties were then used to design the subsequent propped fracture treatment, which was normally pumped the same day.

The full Datafrac consists of three parts:

1. Step-rate test
2. Pump-in/Flow-back
3. Calibration frac

STEPRATE

The Step-rate test consists of pumping a non-wallbuilding fluid (water) at low rates (+/- 0.5 bpm) up to fracturing rate, allowing the pressure to stabilize at each rate before increasing. This provides a means of determining fracturing extension pressure. Figure 6 shows a steprate test for treatment 0162. The pump rate was increased from 1 bpm to 8 bpm. The corresponding stabilized bottom hole pressure is plotted against the pump rate in Figure 7. The two distinct line slopes represent pressure response for fractured (low slope) and matrix (high slope) cases. The intercept of these two lines is the fracture extension pressure, in this case 3960 psi. This pressure gives a good validation for the determination of, and is usually somewhat higher than the closure pressure. The extrapolation of the fracture line to zero rate is theoretically the closure pressure.

PUMP-IN/FLOW-BACK
The Pump-in/Flow-back procedure is accomplished by pumping water at fracturing rate into the formation for a minimum of 5 minutes and then flowing back at a constant rate of +/-20% of the pump in rate. A plot of bottomhole pressure vs time during the flowback will help determine the fracture closure pressure. Figure 8 gives the pressure falloff and derivative for treatment 0162. The derivative aids in determining the inflection point at which the falloff curve goes from concave up to concave down. This represents the closure pressure, in this case 3916 psi. This agrees well with the extrapolation to zero rate, and is 44 psi lower than the fracture extension pressure.

CALIBRATION FRAC
The Calibration Frac is typically an estimated pad volume of fracturing fluid pumped at expected fracturing rates. The pressure during the frac and subsequent falloff are monitored and simulated to determine fluid leakoff characteristics and fracture geometry, and to validate rock properties (Young's Modulus and rock toughness). Several methods were used to accomplish this.

The first method is to analyze the falloff using a 'G-function'. Figure 9 shows a 'G-plot' for the falloff of treatment 0162. The results are listed in Table 1. The slope of the best straight line through the data points to closure pressure is proportional to the total leakoff. In this case the leakoff is 0.00011 ft/min^0.5. This equates to a fluid efficiency of 91%, which is suspiciously high. The slope of the plot at early time is more believable (Figure 10). It represents a total leakoff of 0.00057 ft/min^0.5 which translates to an efficiency of 66%. This early time slope could be indicative of a dual-porosity system or natural fractures. These natural fractures open at a given net pressure increasing the effective leakoff. This method requires a good knowledge of Young's Modulus and fracture height (typically from a radioactive tracer survey).

The next method is gaining popularity and utilizes a pseudo-3D model with a good knowledge of rock stresses in and bounding the fractured zone. In this method, the pressure during the treatment and from the falloff are simulated, and various properties are adjusted to match the pressures. For either method, it is imperative to have bottomhole pressure either from a pressure bomb or from a deadstring to simplify the match. The pressure is simulated from real-time data which helps speed the interpretation.

With either method, the Calibration Frac is typically done the same day as the frac treatment and the additional cost is the materials for the fluid and the extra time on the frac equipment.

Figure 11 shows the fracture treatment 0162 designed from the Calibration Frac. The pad volume was 21% of the total slurry volume and the job was pumped to completion. In this case, 61,000 lb of 16/30 mesh proppant was placed with 12,600 gal of 40 lb/1000 gal borate crosslinked gelled water at a rate of 10 bpm. Figure 12 shows that a fracture height of 200 feet is generated with a fracture half-length of 125'.

ACTUAL FRACTURE TREATMENTS
The average fracture treatments are listed in Table 2. This lists fluid volumes, proppant volumes and average pump-rates with other data. The treatments are small in comparison to other propped fracture treatments in the North Permian Basin for different formations. This is due in most part to the level of comfort of the design engineers in controlled vertical fracture growth.

Treatments in Unit A averaged a pump rate of 7 bpm also down 2-7/8" tubing. The average treatment size was 18,300 gal of 40 lb/1000 gal linear gelled water placing an average of 41,000 lb of proppant. The frac program here is still ongoing and the average treatment sizes are increasing as knowledge of the field increases.

Treatments in Unit B averaged 9,900 gal of 40 lb/1000 gal borate crosslinked gelled water with an average of 40,500 lb of proppant placed. The average rate was 10 bpm pumped down 2-7/8" tubing. There were 6 propped fracture treatments completed in Unit B.

Unit B averaged a treatment rate of 10 bpm down 2-7/8" tubing. The average fluid volume of 14,800 gal of 40 lb/1000 gal borate crosslinked gelled water was required to place an average of 61,400 lb of proppant. This unit was unique in that the fluid leakoff properties varied greatly from well to well. Certain wells exhibited high leakoff while others were very efficient.

AFTER-FRAC PRODUCTION

The wells in all of the units studied exhibited higher decline rates after the frac treatments than before the treatment (Table 3). This is to be expected and is also true with acid treatments. The average decline for all of the wells in this study was 28.8% compared to a pre-frac decline of 20.2%. The average fraced well increased from a production rate of 12.7 bopd to 35 bopd. Figure 13 shows the average well oil production 4 months prior to, and 12 months after frac (where available).

Unit A exhibited an after-frac decline rate of 26% which compares to an after-acid decline rate of 62.9%. The average fraced well increased from 8.5 to 32 bopd stabilized. These units responded the most strongly, with excellent stabilized increases in oil production rate. The program continues here with attempts to achieve more fracture extension. This will be aided by the procedure of placing artificial barriers in the formation.

The average decline rate after frac jobs in the Unit B was 54.6% compared to an average decline rate for an acid job of 72.8%. The average oil production rate increased from 14.3 bopd to 38 bopd stabilized on this unit. This unit responded the least to the fracture program. This was probably due to an overestimation of the in-situ formation permeability, and thus the optimum geometry of the frac. The response would have been better with longer, narrower fracs (linear gels).

The average decline rate after frac jobs in the Unit C was 28.8% compared with 46.9% decline after acid treatments. The average production on this unit increased from 16.5 bopd to 50.5 bopd. The response in this unit was good and it is recommended to continue the program in the near future.

SUMMARY

In the past, propped fracturing was done in the North Permian Basin San Andres with little understanding for failures or successes. Fracturing technology has made great strides in the last few years, and use of this technology has turned a failed stimulation process into a successful one. Advances in fluid quality control and efficiency, combined with better monitoring, computer simulation and techniques have made this program successful.

The fracture program studied in the San Andres has been successful. The methodology for this study can be successfully modified for any San Andres fracture program. The lower permeable wells in this study seemed to benefit the most in terms of sustained increased production rates compared to acid treatments.

GENERAL RECOMMENDATIONS

The success of any stimulation program depends, of course, on the availability of data and its'correct use. The earlier during the program this data can be collected, the earlier the program will be on track to success.

1. Optimize the fracture geometry for each area based on available reservoir properties
2. Maximize fracture extension within the limits of the rock stresses. Consider placing artificial barriers to safely generate more extension.
3. Gather as much data during the fracture treatment as economically possible to assist in future treatments. This includes, but is not limited to:
    a. Fracture height (RA tracers)
    b. Bottom-hole treatment pressure (*essential!*)
    c. Several shut-downs during pad
    d. DataFRACs
4. Optimize breaker schedules in order to maximize fracture conductivity
5. Use previously collected data to modify future treatments

REFERENCES

1. Cleary, M.P., et al, Major New Developments in Hydraulic Fracturing, with Documented Reductions in Job Costs and Increases in Normalized Production, SPE 28565, 1994

2. Economides, J.J. and K.G. Nolte, Reservoir Stimulation, 1989

3. Mukherjee, H., et al, Successful Control of Fracture Height Growth by Placement of Artificial Barriers, SPE 25917, 1993

4. Pferdehirt, D.J., et al, New Stimulation Techniques Improve Canyon Sand Gas Production: A Case Study, SPE 20133, 1990

5. Castillo, J.L., Modified Fracture Pressure Decline Analysis Including Pressure-Dependent Leakoff, SPE 16417, 1987

6. Nolte, K.G., Determination of Fracture Parameters From Fracturing Pressure Decline, SPE 8341, 1979

7. Balen, R.M., et al, Applications of the Net Present Value (NPV) in the Optimization of Hydraulic Fractures, SPE 18541, 1988

8. Penny, G.S., An Evaluation of the Effects of Environmental Conditions and Fracturing Fluids Upon the Long-term Conductivity of Proppants, SPE 16900, 1987

9. Thomas, R., J.E. Brown, The Impact of Fracturing Fluids on Conductivity and Performance in Low-Temperature Wells, SPE 18862, 1989

10. Meng, H-Z, K.E. Brown, Coupling of Production Forecasting, Fracture Eometry Requirements and Treatment Scheduling in the Optimum Hydraulic Fracture Design, SPE 16435, 1987

11. Penny, G.S., 1987 STIM-LAB, INC. Consortium: Final Report on the Investigation of the Effects of Fracturing Fluids Upon the Conductivity of Proppants, 1988

ACKNOWLEDGEMENTS

I would like to thank the management of Schlumberger Dowell for the opportunity to assemble and present the information in this paper. Without management's commitment to technology, the assemblage of the necessary data would have been impossible.

TERMINOLOGY

BPM - Barrels per minute, fracturing pump rate
BOPD - Barrels oil per day, well production rate
Deadstring - A string of fluid, typically the annulus, of known density, which is open to the perforations but remains static during the treatment
Frac - Propped hydraulic fracturing treatment
Frac half-length - One wing of a hydraulic fracture which extends in either direction from the wellbore
Prop - Solid proppant (sand) which holds the fracture open once fracturing hydraulic pressure is relieved
PPA - Pounds proppant added, a concentration of proppant added to a gallon of fracturing fluid

Table 1 - Treatment 0162, Calibration Frac

	Toughness (psi*in^0.5)	Young's Modulus (psi)	Height (ft)	Frac Half length (ft)	Average Width (in)	Total Leakoff (ft/min^0.5)	Efficiency (%)	Net Pressure (psi)
Early-time	2000	7.4e6E6	196	174	0.137	1.22E-4	91	424
Late-time	2000	8.3E6	196	141	0.123	5.48E-4	66	423

Table 2 - San Andres, Fracture Treatments

UNIT	TREATMENTS	AVERAGE FLUID VOL (GAL)	AVERAGE PROP VOL (LB)	AVERAGE PUMP RATE (BPM)	AVERAGE PAD VOLUME (%)
A	14	18,300	41,000	7	45
B	6	9,900	40,500	10	43
C	15	14,800	61,400	10	41
TOTAL	**35**	**15,360**	**49,700**	**8.8**	**43**

Table 3 - After-fracture, Production Results

UNIT	TREATMENTS	PRE-DECLINE (%)	POST-DECLINE (%)	PRE-FRAC PROD (BOPD)	POST-FRAC PROD (BOPD)
A	14	17.6	26	8.5	32
B	6	24.6	54.6	14.3	54.6
C	15	21.5	28.8	16.5	50.5
TOTAL	35	20.5	**32.1**	**12.9**	**43.8**

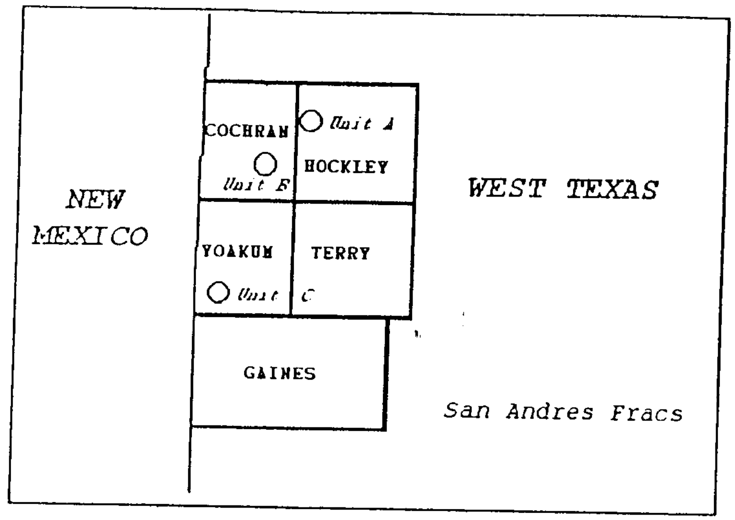

Figure 1

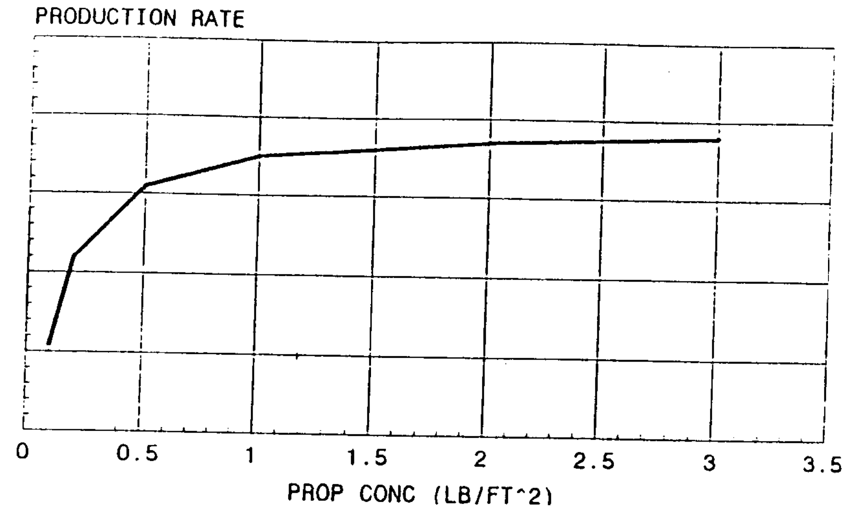

Figure 2 - San Andres, Frac Sensitivity

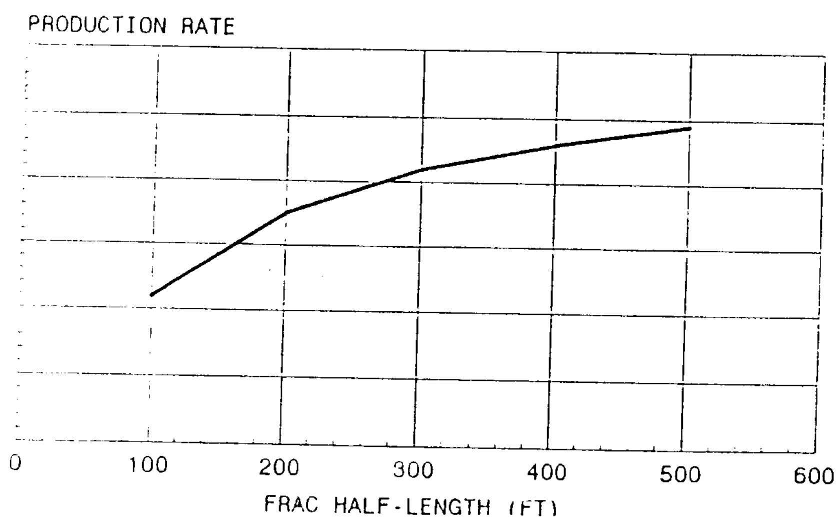

Figure 3 - San Andres, Frac Sensitivity

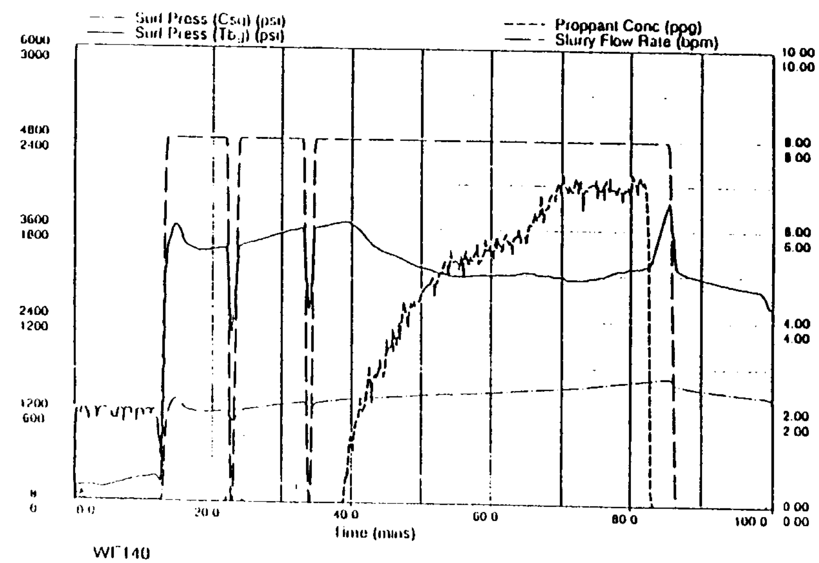

Figure 4 - Treatment 1572, Sandfrac

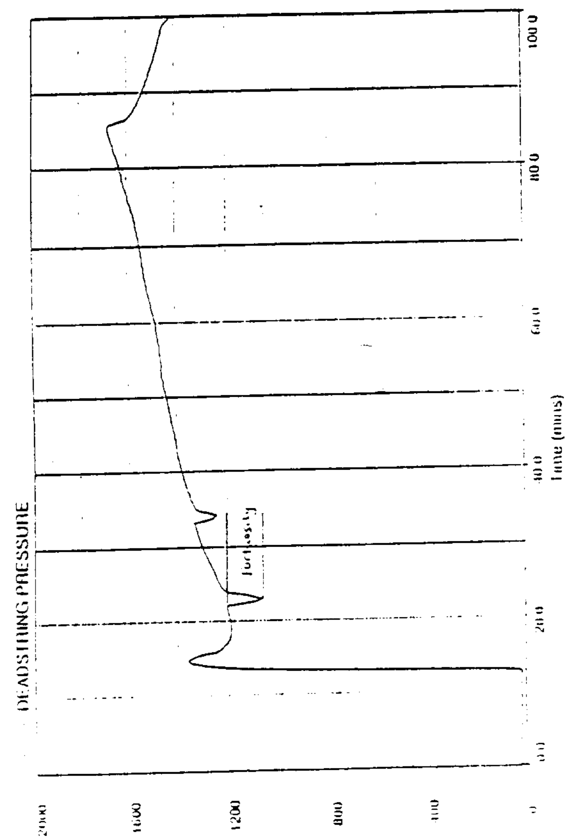

Figure 5 - Treatment 1572, Sandfrac-Tortuosity

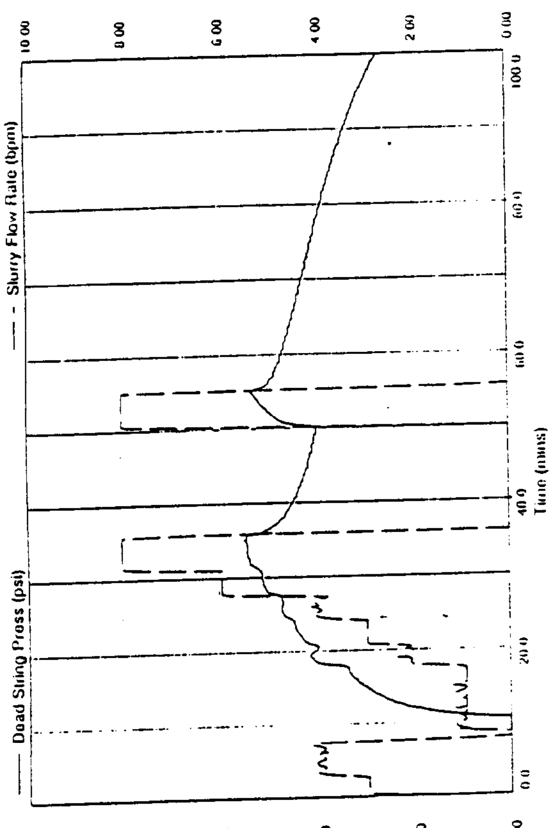

Figure 6 - Treatment 0162, Steprate

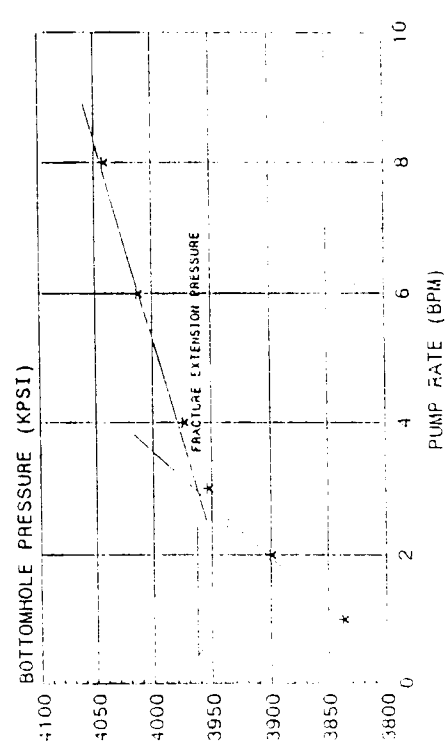

Figure 7 - Treatment 0162, Steprate

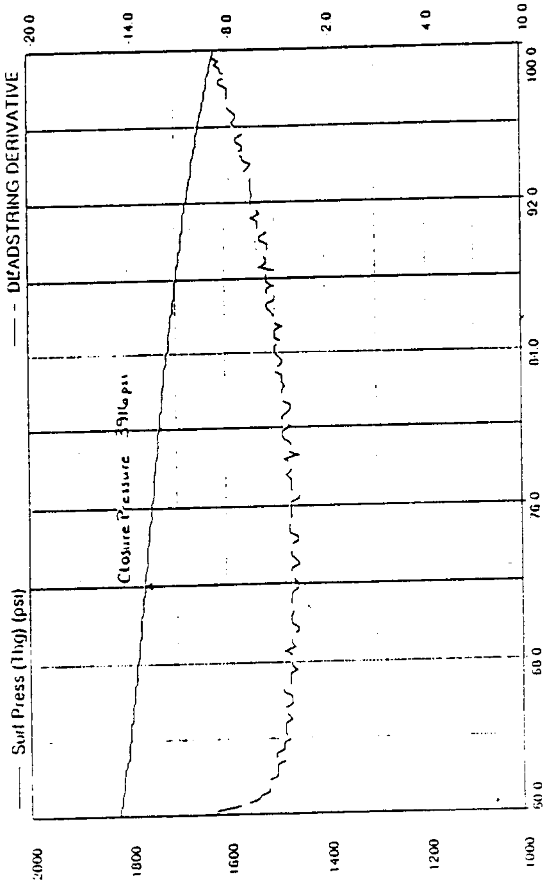

Figure 8 - Treatment 0162, Falloff

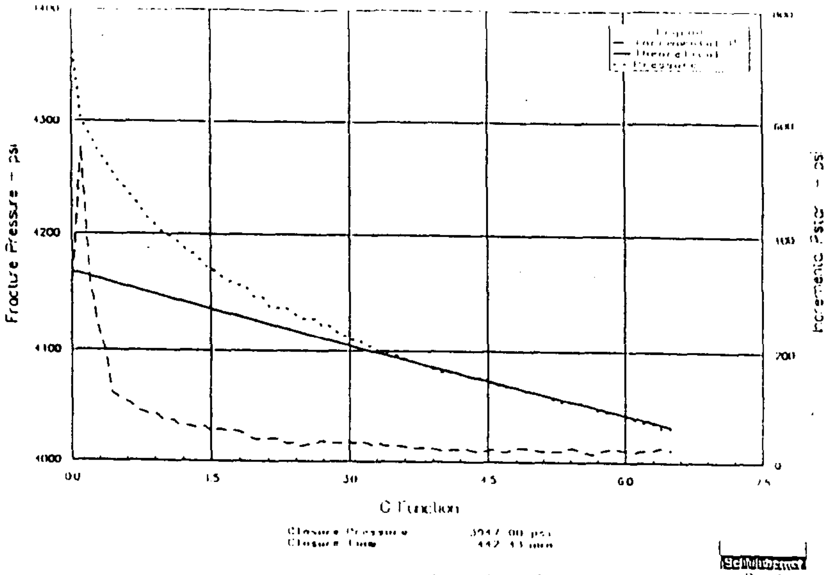

Figure 9 - FracCADE, G Plot

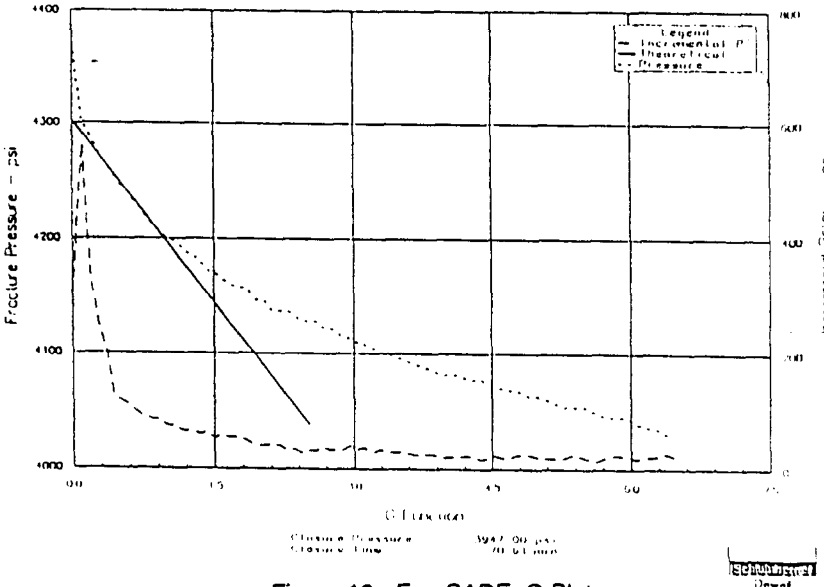

Figure 10 - FracCADE, G Plot

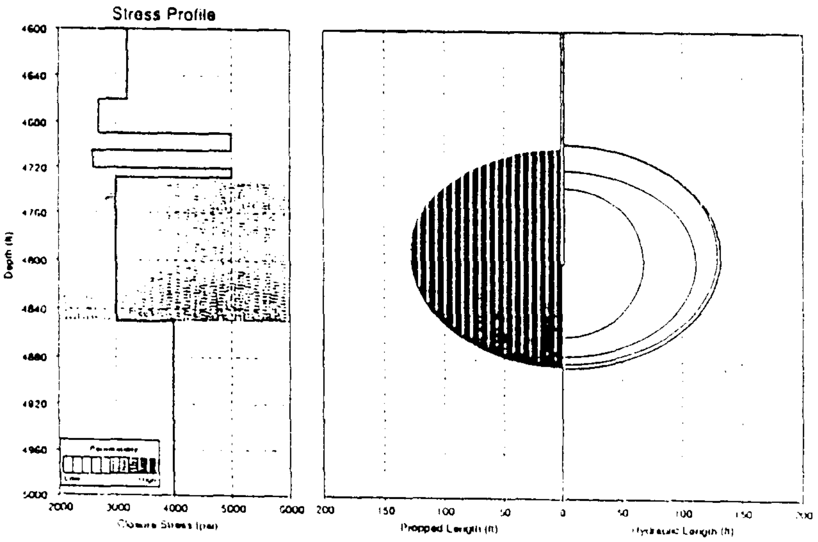

Figure 11 - Treatment 0162

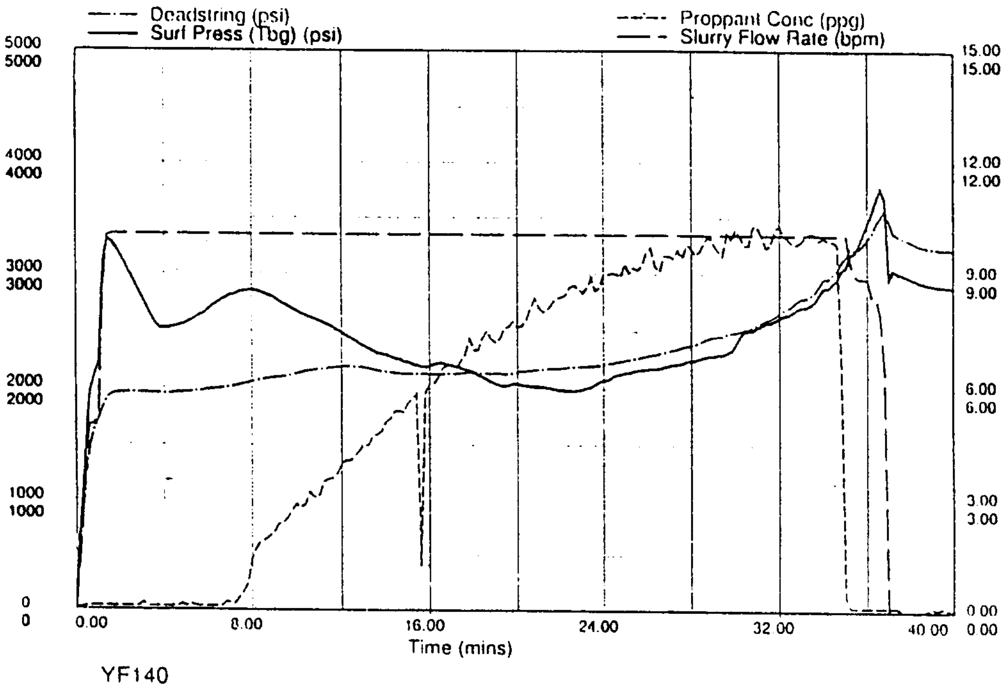

Figure 12 - Treatment 0162, Sandfrac

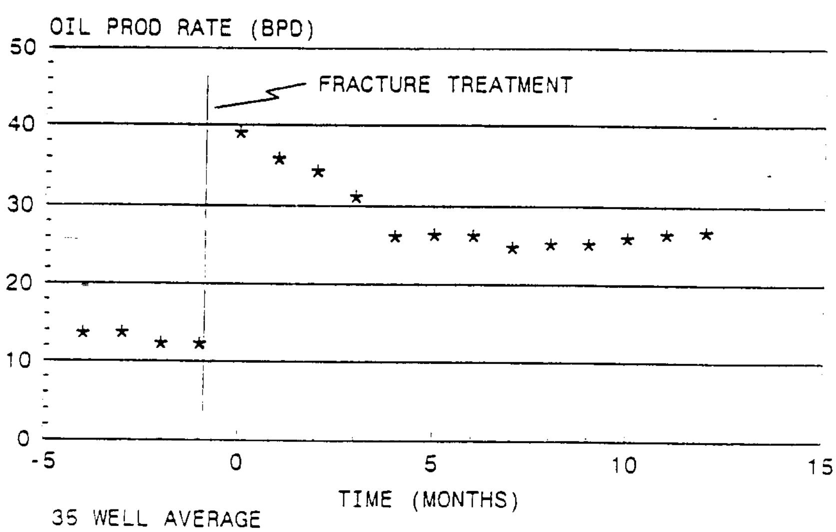

Figure 13 - San Andres Frac Program, Oil Production Rate