THE THEORETICAL AND MECHANICAL ASPECTS OF ULTRA HIGH SAND CONCENTRATIONS IN HYDRAULIC FRACTURING

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ABSTRACT

This paper discusses the theoretical advantages of ultra high sand concentrations (UHSC) in hydraulic fracturing treatments. Results from several treatments are presented. For comparative purposes, results from conventional, lower sand concentration treatments are presented.

Mechanical aspects of handling ultra high concentrations of sand (10 lb/gal and greater) at injection rates from 40 to 70 BPM have been a major consideration in conducting these treatments. Sand concentrations, at these rates, have been unattainable in the past partially due to sand handling problems. The capability of handling sand under these conditions has been developed and is discussed.

INTRODUCTION

It has been well established[1,2,3,4] in the area of hydraulic fracturing that a high sand concentration in the created fracture has many advantages. These advantages relate to more complete fracture fill-up, higher fracture flow capacity, greater sand crushing resistance, greater sustained fracture flow capacity, and ultimately, a potentially higher production increase and higher sustained production.

One of the problems with attaining high sand concentrations in the fracture can be the ultra high sand concentrations required in the fluid at the surface. Due to equipment and fluid limitations in the past, many fracturing treatments were limited to <u>maximums</u> of 3 to 4 lb/gal for short periods of time. However, with new developments in fluids and the ability to mechanically handle sand, the ultra high sand concentrations of 10-15 lb/gal at injection rates of 40 to 70 BPM are being achieved.

This paper discusses the theory behind the use of ultra high sand concentrations, presents a comparison of conventional treatments versus ultra high sand concentration treatments, and briefly discusses the mechanical aspects of handling sand at high concentrations and injection rates.

THEORY

Production increase equations have been developed[5,6] which allow the prediction of the production increase expected from a given hydraulic fracturing treatment. The equations of Tinsley, et al[5], indicate that the post frac production increase is controlled by the conductive fracture height in relation to the net pay interval, the conductive fracture length in relation to the drainage radius and the fracture-formation relative capacity. As shown on Figure 1, the relative capacity is a function of fracture flow capacity as compared to formation permeability[5]. A high relative capacity is desired for greater production increase for a given fracture length and also for a more sustained production increase. As reported by Coulter and Wells[2], the fracture flow capacity is related to the sand concentration in the fracture, Figure 2, and a small amount of fines (60-100 mesh size particles) from the formation or other sources can drastically reduce fracture flow capacity, Figure 3. These results also indicated that the higher the proppant concentration in the fracture, the less effect fines would have on the fracture flow capacity, Figure 3. Also, as shown in Figure 4, the percent of sand crushed under given conditions is related to the concentration of the sand in the fracture[2]. A higher fracture flow capacity than initially required may be necessary to maintain the required fracture flow capacity throughout the life of the well. One way to attain higher flow capacity is through the development of a wide fracture and the use of ultra high sand concentrations.

Existing equations[7,8] are used in the design of a fracturing treatment to determine the quantity of sand required for a given relative capacity. An example design is shown in Figure 5. This design shows the input data required for design calculations, the calculated design, the proppant pumping schedule, and the proppant concentration in the fracture at various frac length intervals.

CONVENTIONAL TREATMENTS

For comparative purposes, conventional, lower sand concentration treatments were reviewed. The computer print-out shown in Figure 5 is a typical frac design for a conventional treatment of San Andres wells in West Texas. From this design it is seen that the average proppant concentration in the fracture is 0.5 lbs/ft^2. From existing data, with a closure pressure of 2,500 psi, the expected fracture flow capacity is 1,058 md-ft. Based upon a formation permeability of 0.5 md, a relative capacity is calculated and plotted on Figure 6, point A.

ULTRA HIGH SAND CONCENTRATION TREATMENTS (UHSCT)

A typical UHSC frac design for a San Andres well in West Texas is shown in Figure 7. From this design it is seen that the average proppant concentration is 2.48 lbs/ft^2. From existing data, with a closure pressure of 2,500 psi, the expected fracture flow capacity is 3,637 md-ft. Based upon a formation permeability of 0.5 md, a relative capacity is calculated and plotted on Figure 6, point B.

The production history from conventional and UHSC treatments indicates improved productivity from the UHSC treatments. There are potentially several explanations for this difference. As previously discussed, in the case of the UHSC treatments, the higher fracture flow capacity, possibly less sand crushing and more resistance to the effects of fines all would be expected to contribute to the better production. Also, as the fracturing treatment designs, Figures 5 and 7 indicate, the propped fracture length is greater for the UHSC treatment resulting from an increased injected slurry volume and from increased fracturing fluid efficiency from the higher injection rate. Also, as the sand concentration in the fracture for various distances from the well data shows, Figure 5, the leading edge of the fracture has a very low concentration of proppant. The sand concentration of 0.3 lbs/ft^2 and less results in an approximate monolayer or partial monolayer proppant system. With time, this portion of the fracture may close due to sand crushing and/or embedment. This being the case, the effective fracture length will decrease with time. Referring to Figure 6 again, it can be seen that point A would drop down to a lower level, i.e., lower L/r_e due to the loss in length. This effect would not be as drastic for the UHSC treatment. The UHSC treatment results in much higher proppant concentrations in the fracture.

CASE HISTORIES

Below is a summary of several UHSC treatments which have been carried out in the San Andres formation in West Texas.

Case History 1

The production history of one well is shown in Figure 8. This San Andres well was initially completed in 1976 utilizing a conventional fracturing treatment. It consisted of 20,000 gallons of crosslinked gel with 20,000 lbs of 20/40 sand at 15-20 BPM. The same interval in this well was refractured in 1979 utilizing an UHSC treatment. The treatment consisted of 45,000 gallons of crosslinked gel carrying 322,400 lbs of 20/40 sand at 50 BPM.

The initial results following the UHSC treatment show improved results over the 1976 initial completion. At the time of this writing it is not possible to say how the production decline on this refrac will compare to the initial completion treatment; however, early evidence indicates it will be much superior.

Case History 2

The production history for four San Andres wells is shown in Figure 9. The production values are cumulative for the number of wells shown. The information on the fracturing treatment for Well #1 was not available. Well #2 was completed in 1977 and fractured with 45,000 gallons of crosslinked gel carrying 140,000 lbs of 20/40 sand at 50 BPM. Well #3, completed in early 1978, was fractured with 40,000 gallons of crosslinked gel carrying 155,000 lbs of 20/40 sand at 50 BPM. Well #4, completed in August, 1978, was fractured with 40,000 gallons of crosslinked gel carrying 180,000 lbs of 20/40 sand at 50 BPM. The incremental increase for each additional well brought on production can be seen as well as an estimate of the decline. When Well #4 was put on production, total production had to be reduced to remain within allowable. As the fluid volumes and sand quantities indicate, sand concentrations were being increased with each treatment. It was during this period of time that we were moving into the UHSC treatments. This production data is presented since it is the longest term production data available from these types of treatments.

Evaluating 45 other San Andres wells in the Lease A and Lease B area, it was found that the average decline on these wells was approximately 9.5 percent per year. The early data on the UHSC treatments indicates the decline will be less than 9.5 percent per year.

TREATMENT CONSIDERATIONS

Fracturing treatments using ultra high sand concentrations have been unattainable in the past mainly due to inefficiency of treating fluids and the difficulties using conventional surface equipment to effectively blend up to 15 pounds of sand per gallon into the selected treating fluid at high injection rates. Using today's fluids and by modifying and incorporating equipment originally designed for massive hydraulic fracturing, ultra high sand concentration treatments are being routinely performed.

Fluids

The fluid used to successfully perform these fracturing treatments is a low residue crosslinked guar which is compatible with most formations in the Permian Basin. The gel concentration selected is based upon the formation temperature, depth, size of tubular goods, number of perforations, and desired injection rate. Formation characteristics dictate other additives such as fluid loss additive concentration, surfactants required, etc. Given the proper number of perforations and a properly designed treatment, this fluid will place 20/40 sand up to 15 lb/gal and with proper pre-wetting of the sand, higher concentrations may be achieved.

Other

Typically 300,000 to a million pounds of sand has to be on location and readily transferable at rates of 30,000 lbs (300 sacks) per minute to be blended with the fracturing fluid. By using massive hydraulic fracturing sand storage bins and a series of conveyor belts, the large quantities of sand necessary can be easily stored on location and efficiently handled at the high transfer rates. In UHSC treatments, the concentrations of sand in fluids reach high percentages. It would be expected that severe difficulties might occur with conventional sand-fluid proportioning equipment at these high concentrations and injection rates. However, equipment modifications and modern proportioning equipment has made the blending of fluid and large sand quantities at high injection rates commonplace. Because the sand volumes approach high percentages of these treatment volumes, metering of sand concentrations should not be left to conventional metering methods. Metering of the proper sand concentrations at high injection rates has been and should continue to be monitored and controlled using radioactive densometers.

Figure 10 shows schematically the equipment required for this UHSC treatment as well as the equipment layout on location.

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NOMENCLATURE

FC = Fracture flow capacity

h_f = Conductive fracture height

h_i = Net formation thickness

J_{fs} = Production from fractured system

J_i = Initial production, prior to fracturing, no damage

K_i = Formation permeability to produced fluids

L = Conductive fracture length, from wellbore to fracture tip

RC = Relative capacity

RCF = Relative capacity factor

r_e = Drainage radius for well

r_w = Wellbore diameter

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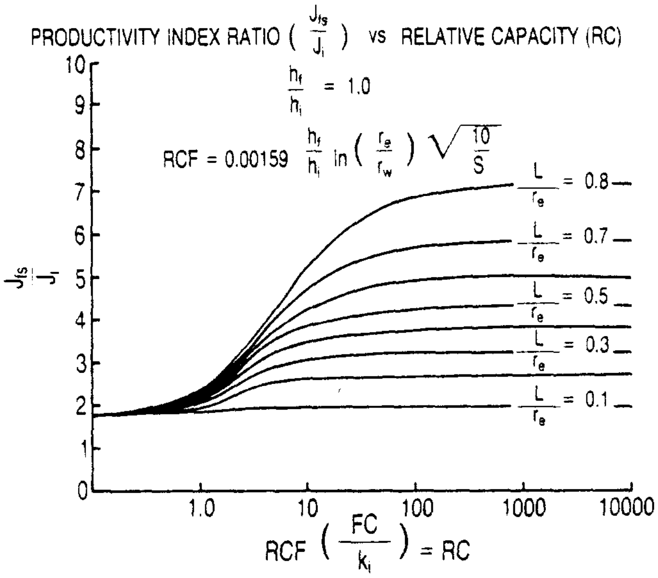

FIGURE 1—PRODUCTION INCREASE CURVES FROM TINSLEY, ET AL[5].

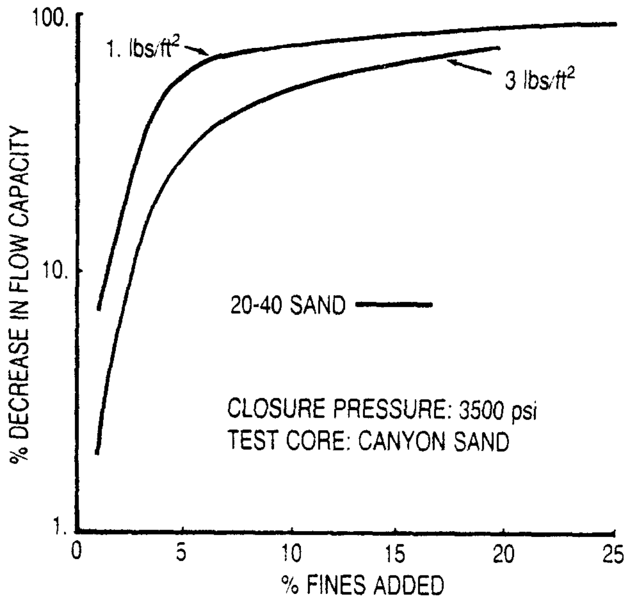

FIGURE 3—PERCENT FINES ADDED VS PERCENT DECREASE IN FLOW CAPACITY FROM COULTER & WELLS[2]

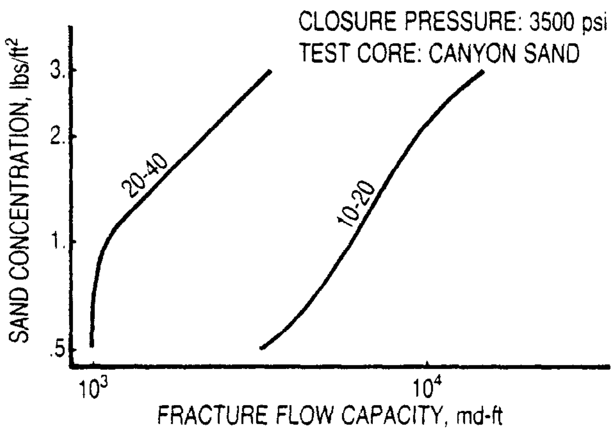

FIGURE 2—FRACTURE FLOW CAPACITY VS SAND CONCENTRATION FROM COULTER & WELLS[2]

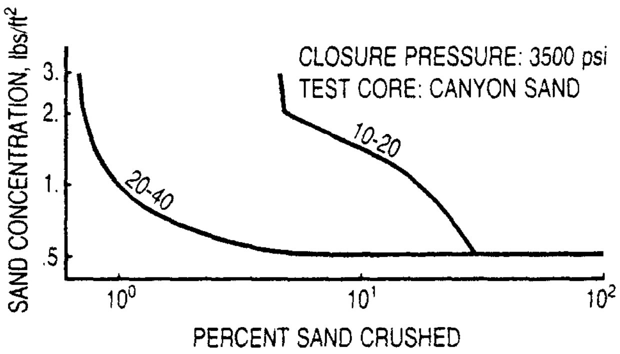

FIGURE 4—PERCENT SAND CRUSHED VS SAND CONCENTRATION FROM COULTER & WELLS[2]

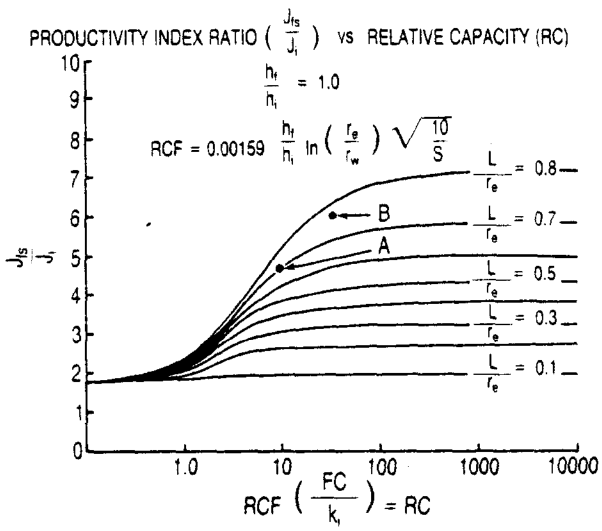

FIGURE 6—RELATIVE CAPACITY PLOTTED FOR CONVENTIONAL TREATMENT, A AND UHSC TREATMENT, B

SAN ANDRES FORMATION COVENTIONAL TREATMENT DESIGN CROSSLINKED DERIVATIZED GUAR FLUID JOB TYPE — X-LINKED GEL FRACTURING SERVICE

WELL & FORMATION DATA

YOUNGS MODULUS	6.00E - 06	PSI
PERMEABILITY	0.5000	MD
POROSITY	10.0	%
RESERVOIR FLUID COMPRESSIBILITY	2.50E-05	1/PSI
RESERVOIR FLUID VISCOSITY	2.00	CP
BHTP	3000.	PSI
RESERVOIR FLUID PRESSURE	1500.	PSI
CLOSURE PRESSURE	2500.	PSI
GROSS FRACTURE HEIGHT	100.	FT
NET FRACTURE HEIGHT	50.	FT
WELLBORE DIAMETER	7.88	IN.
DRAINAGE RADIUS	933.	FT
WELL SPACING	80.	ACRES

TREATMENT DATA

TYPE OF GEL	HPG	
GEL CONCENTRATION	50 LBS./MG	
INJECTION RATE	20.0	BPM
TREATMENT FLUID SP GR	1.020	
N	0.4100	
K (SLOT)	0.050000	LBF-SEC**N/SQ FT
CW—FLUID LOSS COEFF	0.00200	FT/SQRT (MIN)
SPURT VOLUME	0.0	GAL/SQ FT
CVC—SPURT LOSS COEFF	0.00056	FT/SQRT (MIN)
SPURT TIME	0.0	MIN
DAMAGE RATIO	1.0	
APPARENT VISCOSITY	258.	CP, AT 0.431 IN. WIDTH

DESIGN NO	VOLUME TOTAL PAD (GAL/1000)	CREATED LENGTH (FT)	WIDTH AVG (IN.)	PROP LENGTH (FT)	PROP HEIGHT (FT)	PROP TOTAL (SX)	RELATIVE CAPACITY (FT)	PROD INCR (T)	FLUID EFF-%
1	53.0 10.0	832.0	0.431	664.0	99.3	665.	9.41	4.7	84.3

FIGURE 5—EXAMPLE FRAC DESIGN

BED DEPOSITION FOR DESIGN NO. 1

PUMPING SCHEDULE

10000.0 GALLONS OF PAD VOLUME
7000.0 GALLONS WITH 0.50 LB/GAL OF 20/40 MESH SAND
7000.0 GALLONS WITH 1.00 LB/GAL OF 20/40 MESH SAND
7000.0 GALLONS WITH 1.50 LB/GAL OF 20/40 MESH SAND
9000.0 GALLONS WITH 2.00 LB/GAL OF 20/40 MESH SAND
5000.0 GALLONS WITH 2.50 LB/GAL OF 20/40 MESH SAND
5000.0 GALLONS WITH 3.00 LB/GAL OF 20/40 MESH SAND
665. SACKS TOTAL PROP

DEPOSITION PROFILES

AT THE END OF PUMPING:

CARRY DISTANCE	664.0 FT
MAX BED HEIGHT	0.1 FT
AVG BED HEIGHT	0.1 FT
% PROP DEPOSITED	0.4%

DISTANCE FROM WELL	DEPOSITED PROP BED HEIGHT, FT END OF PUMPING	FINAL	SUSPENDED PROP HEIGHT FT	CONCENTRATION LB/GAL	LB/SQ FT
4.0	0.1	19.6	100.0	3.0	1.03
56.0	0.1	19.6	99.9	3.0	1.03
88.0	0.1	17.9	99.9	2.6	0.86
140.0	0.1	17.4	99.8	2.6	0.86
168.0	0.1	14.9	99.7	2.1	0.69
220.0	0.1	14.2	99.6	2.1	0.69
240.0	0.1	14.3	99.6	2.1	0.68
292.0	0.1	14.6	99.5	2.1	0.68
312.0	0.1	12.0	99.4	1.6	0.50
364.0	0.0	11.4	99.3	1.6	0.50
416.0	0.0	10.9	99.2	1.6	0.50
424.0	0.0	8.8	99.0	1.1	0.31
476.0	0.0	8.0	99.0	1.1	0.31
528.0	0.0	8.4	98.9	1.1	0.31
540.0	0.0	5.1	98.7	0.6	0.14
592.0	0.0	4.2	98.6	0.6	0.14
644.0	0.0	4.6	98.5	0.6	0.14

EQUIVALENT BED

LENGTH = 664. FT
HEIGHT = 99.3 FT
BED CONCENTRATION = 504. LB/1000 SQ FT
FLOW CAPACITY = 1058. MD-FT

SAN ANDRES FORMATION COVENTIONAL TREATMENT DESIGN CROSSLINKED DERIVATIZED GUAR FLUID JOB TYPE — X-LINKED GEL FRACTURING SERVICE

WELL & FORMATION DATA

YOUNGS MODULUS	6.00E + 06	PSI
PERMEABILITY	0.5000	MD
POROSITY	10.0	%
RESERVOIR FLUID COMPRESSIBILITY	2.50E-05	1/PSI
RESERVOIR FLUID VISCOSITY	2.00	CP
BHTP	3000.	PSI
RESERVOIR FLUID PRESSURE	1500.	PSI
CLOSURE PRESSURE	2500.	PSI
GROSS FRACTURE HEIGHT	100.	FT
NET FRACTURE HEIGHT	50.	FT
WELLBORE DIAMETER	7.88	IN.
DRAINAGE RADIUS	933.	FT
WELL SPACING	80.	ACRES

TREATMENT DATA

TYPE OF GEL	HPG	
GEL CONCENTRATION	50 LBS./MG	
INJECTION RATE	50.0	BPM
TREATMENT FLUID SP GR	1.020	
N	0.4100	
K (SLOT)	0.050000	LBF-SEC**N/SQ FT
CW—FLUID LOSS COEFF	0.00200	FT/SQRT (MIN)
SPURT VOLUME	0.0	GAL/SQ FT
CVC—SPURT LOSS COEFF	0.00068	FT/SQRT (MIN)
SPURT TIME	0.0	MIN
DAMAGE RATIO	1.0	
APPARENT VISCOSITY	192.	CP, AT 0.530 IN. WIDTH

DESIGN NO	VOLUME TOTAL PAD (GAL/1000)	CREATED LENGTH (FT)	WIDTH AVG (IN.)	PROP LENGTH (FT)	PROP HEIGHT (FT)	PROP TOTAL (SX)	RELATIVE CAPACITY (FT)	PROD INCR (T)	FLUID EFF-%
1	66.1 10.0	892.0	0.530	716.0	99.9	3550.	32.52	6.0	89.2

FIGURE 7—EXAMPLE FRAC DESIGN, UHSC TREATMENT

BED DEPOSITION FOR DESIGN NO. 1

PUMPING SCHEDULE

10000.0 GALLONS OF PAD VOLUME
2000.0 GALLONS WITH 1.00 LB/GAL OF 20/40 MESH SAND
2000.0 GALLONS WITH 2.00 LB/GAL OF 20/40 MESH SAND
4000.0 GALLONS WITH 4.00 LB/GAL OF 20/40 MESH SAND
5000.0 GALLONS WITH 6.00 LB/GAL OF 20/40 MESH SAND
6000.0 GALLONS WITH 8.00 LB/GAL OF 20/40 MESH SAND
6000.0 GALLONS WITH 10.00 LB/GAL OF 20/40 MESH SAND
6000.0 GALLONS WITH 12.00 LB/GAL OF 20/40 MESH SAND
3000.0 GALLONS WITH 13.00 LB/GAL OF 20/40 MESH SAND
6000.0 GALLONS WITH 14.00 LB/GAL OF 20/40 MESH SAND
3550 SACKS TOTAL PROP

DEPOSITION PROFILES

AT THE END OF PUMPING:

CARRY DISTANCE	716.0 FT
MAX BED HEIGHT	0.0 FT
AVG BED HEIGHT	0.0 FT
% PROP DEPOSITED	0.1%

DISTANCE FROM WELL	DEPOSITED PROP BED HEIGHT, FT END OF PUMPING	FINAL	SUSPENDED PROP HEIGHT FT	CONCENTRATION LB/GAL	LB/SQ FT
4.0	0.0	64.4	100.0	14.1	5.93
60.0	0.0	64.5	100.0	14.1	5.93
116.0	0.0	63.8	100.0	14.1	5.93
120.0	0.0	63.2	100.0	13.3	5.53
176.0	0.0	59.6	100.0	12.5	5.07
232.0	0.0	59.2	100.0	12.5	5.07
288.0	0.0	54.4	100.0	10.6	4.14
344.0	0.0	53.5	99.9	10.6	4.14
396.0	0.0	48.2	99.9	8.7	3.18
452.0	0.0	47.5	99.9	8.7	3.18
500.0	0.0	40.0	99.8	6.7	2.26
556.0	0.0	38.6	99.8	6.7	2.26
588.0	0.0	31.0	99.7	4.6	1.41
644.0	0.0	30.0	99.7	4.6	1.41
656.0	0.0	20.1	99.6	2.4	0.67
688.0	0.0	11.0	99.4	1.2	0.32

EQUIVALENT BED

LENGTH = 716. FT
HEIGHT = 99.9 FT
BED CONCENTRATION = 2482. LB/1000 SQ FT
FLOW CAPACITY = 3637. MD-FT

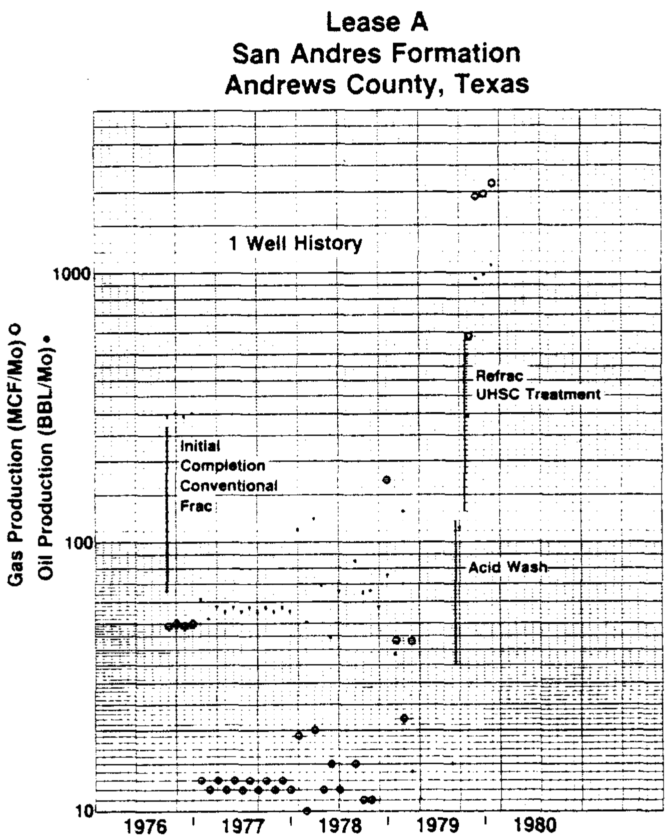

FIGURE 8—CASE HISTORY INFORMATION, LEASE A

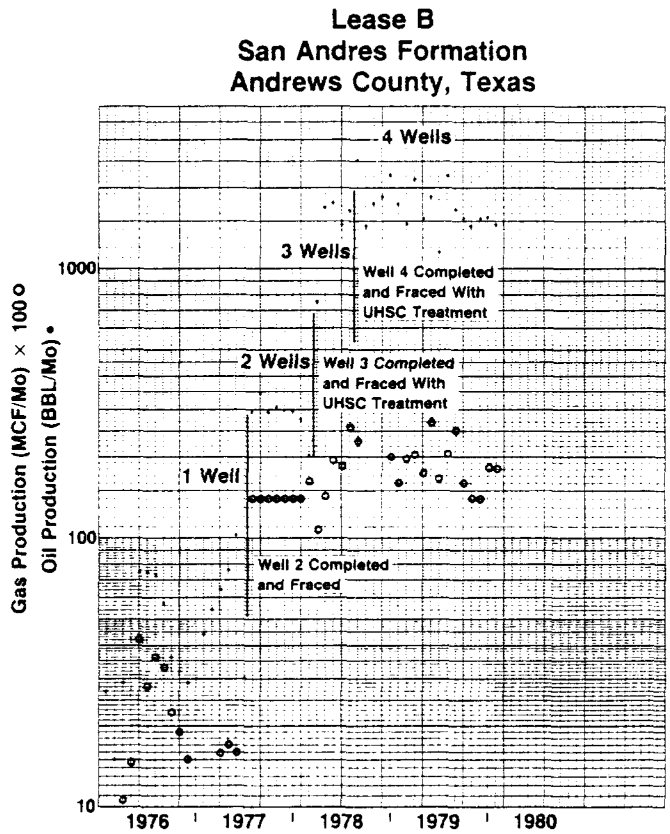

FIGURE 9—CASE HISTORY INFORMATION, LEASE B

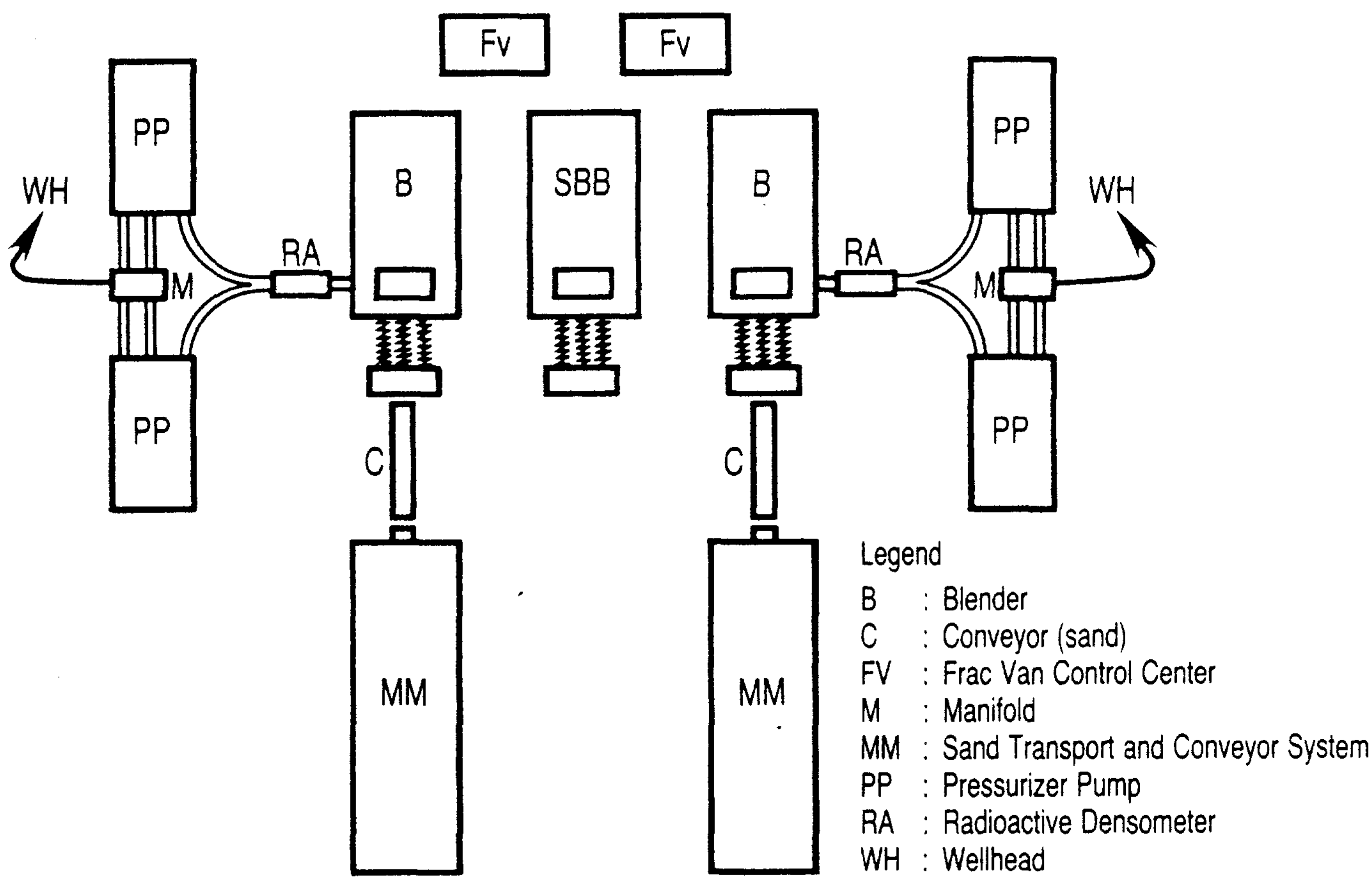

FIGURE 10—EQUIPMENT REQUIREMENTS AND LAYOUTS