THE USE OF FOAM FRACTURING IN THE FT. WORTH BASIN

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ABSTRACT

This paper covers the use of foam fracturing in the Ft. Worth Basin. It will discuss the design parameters and economic considerations in foam treatments. Finally, case histories will show results of production.

INTRODUCTION

The use of a stable foam has grown since 1974 in the industry. The reasons for its growth are:

- Low hydrostatic head
- Excellent transport of particles and liquid
- Low fluid loss
- Low liquid content
- Good rheology properties
- High energy potential
- Low friction loss
- Rapid clean-up

These features bring old and new consideration in treatment design. They are:

- Foam Quality
- Materials
- Job Size
- Perforation Entry Design
- Mechanical Limits
- Economics
- Results

BRIEF GEOLOGICAL DESCRIPTION

The majority of the oil and gas production comes from the Strawn and Bend series of the Pennsylvanian Age. The producing zones are generally lenticular conglomerates made up of various amounts of lime and sand. These lenses are upclip porosity and permeability pinch-outs. The varying composition of the lenses often contain significant amounts of illite, kaolinite, montmorillite, muscovite, feldspar, and pyrite. The quartz grains by description vary from course to fine in size.

The depth of these zones normally range 3,000' to 6,500' in depth. The productive porosity range is 6 to 16%. The permeabilities are .1-1 md with some natural fractures. The frac gradient will span .52-.62 psi/ft.

The pressure in the the lenses will vary from .1 to .45 psi/ft. The BHP is measured by DST or gauge after acid breakdown and clean-up. At this time, it is often the first solid indication the well will be productive.

FLUIDS

Most fracturing fluids used in the industry have been or are being pumped in throughout the Ft. Worth Basin. The weak acid or KCl water base fluids are the primary fluids used. These fluids are gelled with low residue gells in concentrations from 20 lbs. to 60 lbs. and may or may not be crosslinked. The problem with these fluids is the low amount of fluid returned and slow recovery. In many, 30-50% fluid return is considered normal. Successful completion of low BHP wells (500-800 psi) has been extremely difficult with the above fluids.

The addition of N_2 of CO_2 into the fluids will increase the load recovery, but can still make completion difficult in low BHP wells.

The use of foam decreased the lod to be recovered by 70-75%. of the liquid, 30-60% would be rapidly returned because of the large amount of gas used. Actual well clean-up histories are seen on Table #1 and 2.

Another problem with the gelled fluid is the large amount of materials needed to properly treat the fluid for clay control, low-surface tension, gelling agent, and iron sequestering in acid-systems. The foam needs less chemicals to be properly treated.

FOAMS AND FOAM QUALITY

Foams used for fracturing are made of a base liquid, foaming agent, and Nitrogen. The base liquid is usually 2% KCl water or 3% HCl and stabilizing agent. The foaming agent is a blend of surfactants commonly used in stimulation treatments. These materials when mixed with gaseous Nitrogen, foam a homogeneous gas-in-water foam. The gas is dispersed in the liquid as a discontinuous phase of microscopic bubbles.

Foam quality is the term used to describe foams, and is defined as the ratio of gas volume to foam volume at a given pressure and temperature:

$$FQ = \frac{VG}{VF} = \frac{VG}{VG + VL}$$

Where: FQ = Foam Quality, Expressed as a Fraction
VG = Volume of Gas
VF = Volume of Foam
VL = Volume of Liquid

Foam quality may range from 56% to 95%, with the normal range 70 to 75 quality.

Nitrogen in the gas state is highly compressible. The amount needs to occupy a given amount of space increases with a decrease in temperature and/or increase in pressure. This volume can, and must, be determined; therefore, the bottom hole frac pressure and temperature must be known.

FOAMER CONCENTRATION AND FOAM STABILIZER

Foamer volume may range from .3% to .8% of the liquid to create the foam. Due to the absorption of the surfactant to the formation, .5% to .8% is generally run. The foamer will usually be a blend of cationic and nonionic surfactants. An emulsion test with the crude oil or condensate should be run to determine the amount and type of surfactants most compatible.

Foam stabilizer is also run in quantities of 20 to 40 lbs. per 1,000 gallons liquid. Two functions of the foam stabilizer are to increase the half-life of the foam and to increase its viscosity.

The half-life is the time required for half of the liquid phase to separate out. The longer the half-life, the more stable the foam. In the Ft. Worth Basin 30 lbs. of stabilizer has shown optimum results. See Figure 1.

The increased viscosity will reduce leak-off, transport sand more efficiently, and create wider fractures. See Figures 2 and 3.

ZONE COVERAGE

Limited entry has been an effective means of treating multiple zones. Zones with verticle separation of 400' have been successfully treated.

The foam, because of its low density, can achieve greater rates with less perforation friction pressure.

Without this perforation friction pressure it is easier to not pump into all of the holes. Also, with the reduced hydrostatic head (from .438 psi/ft. to .117 psi/ft.) it will take more pump pressure to pump into the lower perforations than the upper ones.

In example 1, we show a well with 2-.41" dia. shots. One is 500' above the other. The well has an FG of .6 psi/ft. and we would like to maintain 2 bpm in the lower perforation. Using 75 quality foam we see the top perforation will be taking 3.5 bpm and with 2% KCl water 2.6 bpm volumes.

In the Fort Worth Basin R.A. Surveys have shown Foam pumped at 20 BPM will treat 12-.31" holes over a 400 ft. interval. Single zone treatments have typically run at 8-10 BPM given good coverage.

VOLUMES

Due to the unknown lens size and characteristics, it is difficult to design the proper theoretical fracture treatment. Field results have shown that designs for 700 ft. or about 55% of the drainage radius generally gives a good cost vs. returns.

In a foam vs. crosslinked computer comparison it will show that the foam will give 40% more penetration and only 75% of the fracture width. Using these figures, a pad volume of 30% of the total fluid has been set as a standard.

Sand concentrations on the norm will run 1 to 3 lbs./gal. Extremes have been as high as 7.5 lbs./gal., but results and a higher percent of screen-outs have not shown this to be practical for normal use. The total sand amount will be about 1 1/2 times the total foam volume or 2 lbs./gal. in the sand carrying foam. This will give an average of 1 lb./ft. in the fracture.

Fifty wells treated under these parameters showed only 2 screen-outs.

SAND CONCENTRATIONS

Foams have a limited amount of liquid (40-20%), and if sand is added in this phase, then the amount of sand is also limited. For example, a 75 quality foam containing four pounds of sand per gallon would require a sand concentration of 16 lbs./gal. in the liquid. It is difficult for most pumping equipment to handle this type of sand concentration consistently. To improve on this, the use of a sand concentrator should be considered. A sand concentrator operates by removing liquid from sand/liquid slurry downstream from the pumping equipment. The clean liquid is then returned to the storage tanks, where it is used again to carry sand to the pumps. Sand concentrators can vary in design, although most operate by centifuging the sand out of the return liquid.

The slurry enters cone tangently, thus creating a spiralling effect. The sand is centrifuged to the outside wall of the cone and exits the tip. The liquid fluid is drawn off the center, de-energized, and returned to the frac tank.

In most applications, 50% of the liquid is removed and the sand concentration is twice that possible without a sand concentrator.

MAINTAINING RATE AND QUALITY

In a waterfrac or oil frac, as the sand concentration increases it displaces the frac fluid and leaves the total rate the same. With a foam frac, the liquid phase is the only part of the foam that is displaced by the sand. This will cause the foam quality to increase.

There are three alternatives:

1. Let the foam quality rise, changing foam propertieies.

2. Increase the liquid rate to account for the volume of sand. This will increase the total injection rate.

3. Adjust the liquid and nitrogen rates to maintain constant rate and constant foam properties.*

*The third alternatives are the most desirable, so that any anomoles in the well treating characterics (chages in rate and pressure) can be seen as down hole conditions.

FLOW BACK

As already mentioned a well's success is often determined by how well it is cleaned up. The object is to flow the well as fast as possible to bring the liquid back before the nitrogen dissipates into the formation, however the flow back must be slow enough not bring the sand with liquid.

The Procedure found most effect is this:

1. After frac, close in for 2 hours.

2. Start flow on 12 or 14/64 inch choke.

3. If no sand in 2 hours, go to 9 16/64 inch choke.

4. Proceed in same sequence up to a 20/64 inch choke.

5. If sand is flowing to surface, reduce choke size down to next size and stabilize flow without sand. Flow 2 hours then proceed back up in size.

Table 1 show case histories of well clean-up. It should also be noted that flow back through tubing is significantly better than through casing.

When flowing this energized fluid back, many safety precautions should be taken. Some of these are a must, such as:

1. High pressure steel line must be connected from the high pressure well head valve to the pit or tank.

2. This line must be tied and staked at various intervals.

3. A positive choke must be used to control flow rate.

The use of adjustable chokes, high pressure hoses, and low pressure well head connections can and have caused several accidents.

ECONOMICS

One of the governing factors of any treatment is its relative cost. For this we took an example well and looked at cost alone in comparing a 70 quality foam frac and 40 lb. crosslinked gell. The pertinent well data is seen on example #2. This shows the foam frac improves the total cost by taking less time and using less material.

It should be noted that since the amount of Nitrogen varies then the cost of 5 gallons of foam varies. This is seen in example #3 as the higher the BHFP the more expensive foam becomes. Also, equipment will change as to amounts and types when comparing other types of treatments.

Rates, materials, and pressures make Foam fracturing a service of variable costs.

WELL RESULTS

Table 1 shows 17 foam fracs on low pressure wells. These wells are good examples that these near depleted zones can be completed, which previously had been thought of as non-productive.

These other results show good results in comparison to gell water fracs.

EXAMPLE 1

Item	Foam	2% KCL
FG-Hydrostatic	241.5 PSI	81 PSI
Lower Perforation Friction Pressure	110 PSI	400 PSI
Total PSI	351.5 PSI	481 PSI
Upper Perforation Rate	3.5 BPM	2.6 BPM

EXAMPLE 2

This well is 5000' - 6000', need 3 seperate treatments, each treatment 30,000 gallons and 45,000 lbs

FG = .54 PSI/FT   BHP = 900 PSI
BHT = 140°   Pump Rate = 20 BPM

Item	70 Quality Foam	40 #Crosslinked
Treatments (3)	52,435	60,445
Water and Tanks	1,700	2,474
Rig Time	18,200	21,000
Total	72,335	83,919

EXAMPLE 3

Cost per gallon of 75 Quality Foam

F = .58 PSI/FT   Temp G = 1.1 0/100 FT.   74°
6 Gallons/1000 Foamer   30#/1000 Foam Stabilizer   Ambient

2500'	4500'	6500'
.158	$.236	$.30

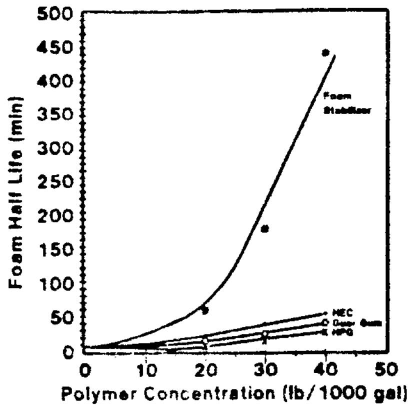

Fig. 1 Effect of Various Polymers
on Foam Fracs

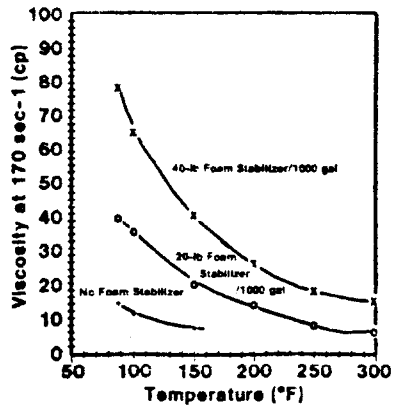

Fig. 2 Viscosity of 75 Quality Foams of
Temperature and 1000 psi

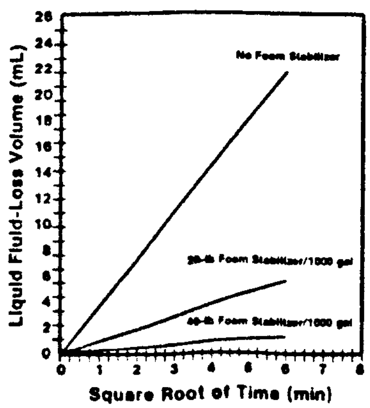

Fig. 3 Fluid loss of 75 Quality Foams

TABLE 1.A

Frac #	Volume X 100 Fluid - Sand	Type	Perforation #/Size	Depth	Clean-Up Days	Clean-Up Recovered/Load	%	BBL Left	Flow Up
1	350 - 475	75Q	19/.31'	5942-60	1	28/260	11	232	2 3/8
2	300 - 300	70Q	10/.31	5564-78	1	44/223	20	179	2 3/8
3	200 - 213	Foam		Mech. Trouble		16/125	13	109	2 3/8
4	200 - 280	70	17/.33	5016-5032	15 hr	80/150	53	70	2 7/8
5	120 - 160	70	14/.33	6917-6924	2 ½	75/150	30	75	2 7/8
6	450 - 582	Foam		5736-5864		110/285	39	175	4 1/2
7	420	Foam	10/.31	5971-6022	3	90/195	46	105	2 7/8
8	350 - 420	75	16/.31	5834-98	1				2 7/8
9	500 - 620	75	10/.31	5738-5518	1	130/362	36	232	2 7/8
10	500 - 650	70	10/.31	5053-5192	1 ½				
11	100 - 850	Foam		3657-3666		9/65	14	56	
12	300 - 410	Gelled H_2O	5/.31	6012-20	2	269/748	36	479	2 3/8
13	600 - 600	70	8/.31	5305-61	2	153/398	48	205	4 1/2
14	130 - 150	70	10/.31	5206-10	1	32/140	23	108	2 3/8
15	300 - 270	75		5748-52	1 ½	35/178	20	143	2 3/8
16	700 - 1000	75	9/.31	5238-5324	1 ½	72/416	17	344	4 1/2
17	500 - 750	70	9/.33	6459-6633	1 ½	181/326	55	145	2 7/8
18	560 - 850	70	10/.31	6007-6048	1 ½	385/431	89	46	2 7/8
19	800 - 1055	Gell	13/.31	5622-5811	2 ½	575/2812	28	1437	2 7/8
20	600 - 780	75		4882-4996	2 ½	68/353	19	285	4 1/2
21		75		4156-4221	1	8/275	4	263	
22	450 - 630	Gell		5580-5816	2	218/1160	19	942	4 1/2
23	450 - 560	Gell		5744-6043	2	173/1163	15	990	4 1/2
24	623 - 799	Gell		5254-5764	2	93/1762	5	1669	2 3/8

TABLE 1.B

Well Name	BHP	Production Before MCFD	Production After MCFD
1	980 psi	Show	893 MCFD @ 800 14/64
2	1321	Show	725 MCFD @ 650 14/64
3	208	Light	0 20/64
4	1500	8 BBL/Hr 110 32/64	13 BBL/Hr 500 32/64
5	2000	1000 & 1 BBL/Hr 300 32/64	1500& 3 BBL/Hr 400 32/64
6	800	80 psi @ 32/64	1736 @ 240 32/64
7	100	Show	1404 @ 600 20/64
8	1560	174 @ 120 psi 16/64	3324 @ 1160 22/64
9	450	Show	588 @ 400 16/64
10	540	147 @ 100 16/64	588 @ 400 16/64
11	268	No Show	Show
12	1560	1611 @ 340 28/64	2648 @ 560 28/64
13	280	851 @ 180 28/64	2270 @ 480 28/64
14	140	Light	Show
15	660	Light	850 @ 180 28/64
16	425	Light	1020 @ 300 24/64
17	1800	1 BBL/Hr Strong Blow	8 BBL/Hr 300 30/64
18	1800	1089 350 22/64	1885 1000 18/64
19	2105	3324 1120 22/64	5780 1700 24/64
20	760	Show	2003 MCFD
21	280	Show	1064
22	1423		1553 @ 1052 16/64
23	1437		2961 @ 1209 20/64
24	1145		2725 @ 512 24/64

TABLE #2

Total Liquid (BBL)	Liquid Returned (BBL)	% Recovered	Liquid Remaining (BBL)	Days	BHP	Tubular Goods	Fluid
92	33	36	59	1	2088	4 ½	
369	75	20	294	1 ½	800	4 ½	
170	97	73	77	1	1344	2 3/8	Foam 75
121	70	58	51	1	2143	2 3/8	
400	206	52	194	1	2070	4 ½	
190	93	49	97	1 ½	1480	2 3/8	Foam 70
345	123	36	222	2	1654	4 ½	
1190	239	30	951	1	2112	2 3/8	Gell + CO_2
1160	218	19	942	1	1704	2 3/8	40# Crosslinked