PREFLUSH CONCEPTS IN FRACTURE ACIDIZING

GENE C. BROADDUS
Halliburton Services

INTRODUCTION

Water preflushes have been used for many years to precede acid fracturing treatments. One of the primary functions performed by the preflush is to establish injectivity into the reservoir before acid fills the tubular goods. Preflushes also perform other functions which can contribute to more efficient use of acids and provide greater effectiveness from acid fracturing.

This paper discusses the influence of preflushes on acid fracture designs and describes preflush systems which have been used successfully.

FACTORS TO CONSIDER IN FRACTURE ACIDIZING

Fracture Geometry

To be successful in fracture acidizing, adequate fracture geometry must be created. Ideally, the created fracture should cover the productive interval vertically and have a length equal to the drainage radius of the well. The fracture, during treatment, should also have adequate width to aid in acid penetration.

The ideal fracture geometry is seldom, if ever, obtained. The vertical fracture height may exceed the productive interval and extend into a barren interval or into unwanted production. The conductive fracture length is usually less than is desired because of inadequate acid reaction time.

The factors that affect fracture geometry are injection rate, volume, fluid loss, and viscosity of the injected fluid. Fracture geometry can be improved by using water preflushes because they tend to lower the fluid loss of the acid that follows by supercharging the area next to the fracture faces. Also, using fluid-loss additives in the preflush aids in further lowering the fluid loss of the acid.

Fracture Conductivity

In any successful fracturing treatment, it is necessary to establish adequate fracture conductivity. In fracture acidizing, conductivity is created by the dissolution of rock from the fracture faces by the reaction of the acid. Both the quantity of rock removed and the pattern in which it is removed from the fracture faces are important. The quantity of rock removed is controlled by the nature of the rock, and also the volume, type and concentration of acid used. The pattern of rock removed is influenced primarily by the rock characteristics.[1,2]

The rock must have adequate solubility, usually in excess of 75%, with some heterogeneity to develop high conductivity. The physical and chemical composition of the rock affects differential rock removal. Homogeneous-type rocks, such as chalks, are usually dissolved uniformly, hence resulting in low conductivity.

Many carbonate reservoirs release fines when acted upon by acid. These fines may be acid-insoluble or they may be fines that are just more slowly soluble than the main portion of the rock. Some of the fines could migrate within the fracture and if the released fines are of sufficient quantity, they may bridge at various points, thus reducing fracture conductivity. Another possibility is that the fines could adhere to the fracture walls, resulting in soft fracture faces that tend to seal when closure pressure is applied.

Consequently, some formations, even though they have adequate acid solubility, may not respond favorably to conventional fracture acidizing due to inability to develop fracture conductivity.

One method of obtaining fracture conductivity in these difficult zones is to expose only a portion of the fracture to acid attack. This can be accomplished by using a viscous preflush ahead of the acid solution. Acid will finger or channel through the viscous fluid because of the mobility difference. This is illustrated schematically in Fig. 1. Acid contacts the fracture faces only in the channels, thus producing highly conductive channels. The areas protected from acid attack by the viscous solution remain higher than the other portions of the fracture and support the closure pressure.

In many fracture acidizing treatments a low salinity or fresh water preflush is used. This is followed by a higher-density acid solution. In vertical or inclined fractures the acid will migrate rapidly to the bottom of the fracture because of the difference in density of the two fluids. This results in the creation of conductivity in the lower portion of the fracture which may be outside the preferred interval. The higher the concentration of acid the greater its density and the more pronounced is the downward movement of acid. As acid spends on limestone or dolomite, the density of acid increases; so, as the distance from the well bore increases, the more pronounced will be the downward movement of the acid.

Knowing that density differences affect acid migration in a fracture can be used to advantage. The vertical movement of the acid in the fracture can be controlled fairly well by adjusting the density of the preflush and overflush.

In zones where the producing interval is near water, the preflush should have a greater density than the acid solution. This will cause the acid to override or migrate toward the top of the fracture and tend to develop conductivity in the upper portion of the fracture only. See Fig. 2.

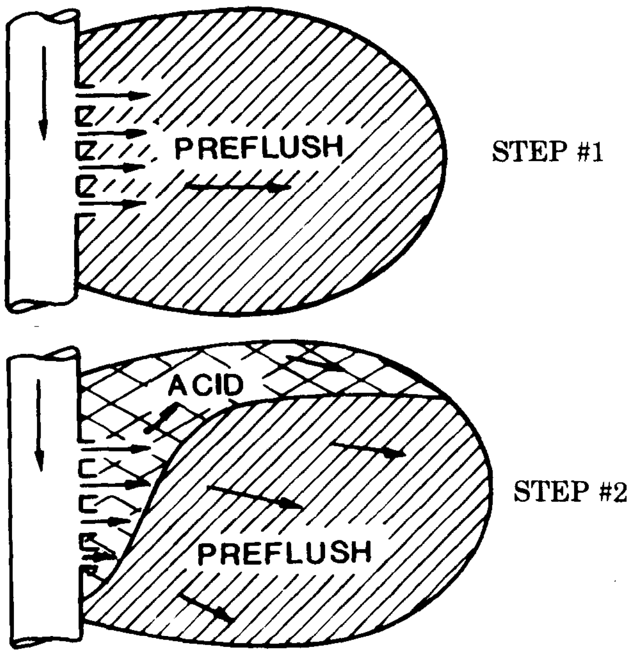

FIG. 2—ACID FLOW HIGH

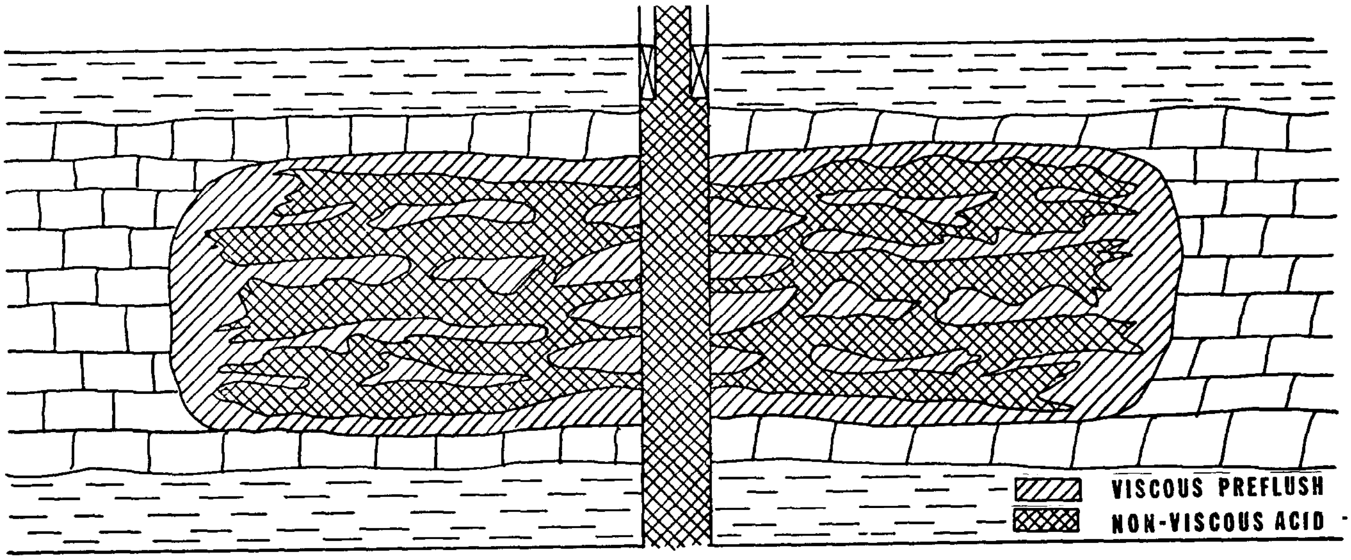

FIG. 1—SCHEMATIC OF VISCOUS PREFLUSH PROCESS

There are also occasions when it is desirable to prevent acid entry into the upper section of a zone to prevent unwanted production. Of course, this is the easiest condition to accomplish. A fresh water or low salinity preflush can be used and the acid will rapidly underride the preflush and create conductivity in the lower portion of the fracture. See Fig. 3.

The fracturing process is dynamic, and the fracture is continually growing. The preflush is moving away from the well bore and is being lost to the matrix. It must be replenished periodically to keep the acid in the desired portion of the fracture. This means that the injection of preflush and acid should be alternated every 10 or 15 minutes.

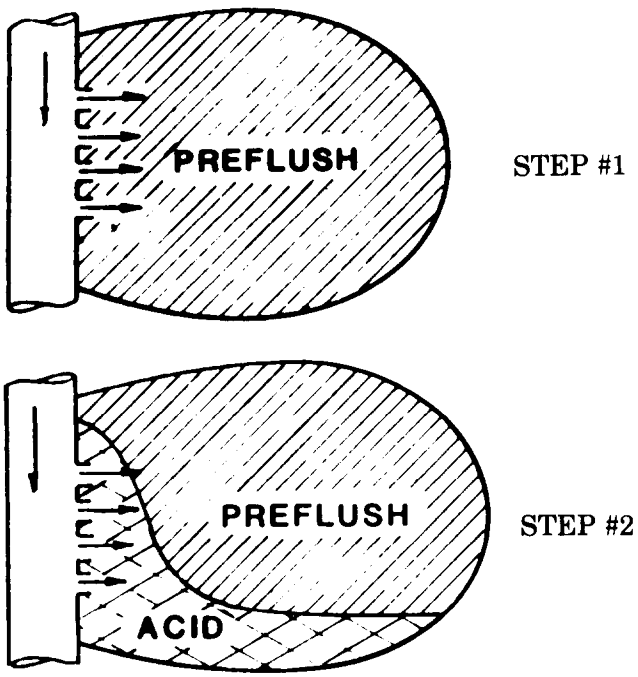

FIG. 3—ACID FLOW LOW

ACID PENETRATION

Fluid Loss

Acid penetration within the fracture is another important factor in fracture acidizing, in addition to conductivity. This determines the distance from the well bore that conductivity can be created.

One factor that controls acid penetration is fluid loss. It is more difficult to control fluid loss with acid solutions than with nonacid solutions because the acid reacts with the formation to continually enlarge the pore sizes. The loss of fluid from the fracture can be diminished by the use of fluid-loss additives in the acid solution. Increased viscosity can also reduce fluid leakoff (See Eq. 1, Table 1). A viscous preflush fluid can aid in lowering leakoff of a following acid solution, since any viscous material lost to the matrix of the rock will offer more resistance to acid leakoff.

TABLE 1—EFFECT OF VIXCOSITY ON FRACTURE WIDTH

Viscosity (cp)	Fracture Width (in)
1	0.038
10	0.0676
100	0.120
1000	0.214

Injection Rate = 10 bbl/min
Fracture Length = 100 ft
Young's Modulus of Elasticity = 10 x 10^6

Equation 1:

$$C_V = 0.0469 \frac{(k\Delta P\varphi)^{1/2}}{\mu}$$

C_V = fluid loss coefficient (viscosity controlled)

k = effective formation permeability to the viscous fluid, in darcies

ΔP = differential pressure across the face of the fracture, in psi

φ = formation porosity, a fraction

μ = fluid viscosity at bottomhole temperature, in centipoises

Any natural fractures that intersect the created fracture will accept large quantities of acid. Fluid-loss additives will *not* lessen this loss because they are composed of small particles designed to control loss of fluid to the matrix permeability. The viscous preflush can enter these natural fractures and lessen the quantity of acid lost to them.

A viscous preflush can help control acid fluid loss in another way, too. Since the acid fingers through the viscous preflush, it will only contact a fraction of the created fracture area. This decreases the area in contact with the acid; consequently, the total loss of acid to the matrix is less.

Acid Reaction Rate

Penetration of reactive acid is also determined by the rate at which acid reacts with the formation rock. If the reaction rate is decreased, the length of conductive fracture will be greater. Among the factors that affect the acid reaction rate are temperature, fracture width and intermixing of live and spent acids within the fracture.[3,4]

The temperature environment to which the acid will be exposed can be lowered by using preflushes, both viscous and nonviscous. The cooling effect produced by the preflush will decrease the reaction rate of the acid and consequently increase penetration.

The fracture width can be increased by using a viscous preflush. This effect is shown in Table 1. The calculations were made using the equation developed by Perkins and Kern.[5] As the fracture width increases, the degree of acid-mixing decreases and the acid-volume to surface-area relationship increases. Both of these decrease the rate of the acid and consequently increase acid penetration.

RESULTS OF MODEL STUDY

Fracture model studies indicate that viscous fingering can be accomplished. There must be an appreciable viscosity difference between the preflush and the acid that follows. Figure 4 (fracture model) shows a slight amount of viscous fingering which is rapidly washed out by the following acid solution. The viscosity difference between the preflush and the acid was not adequate for viscous fingering. Figure 5 (model study) shows well-established viscous fingering, where the viscosity of preflush was adequate to produce viscous fingering. Had the model had a greater vertical height, multiple fingers could have been anticipated.

As the viscosity difference between the preflush and acid becomes greater, the more pronounced the viscous fingering becomes. (The amount of viscous fingering is expressed in per cent.) For example, if the viscous fingering is 25%, this means that 25% of the viscous preflush has been displaced from a given portion of fracture. It also means that 25% of this given fracture area has been contacted by the acid, and 75% of the fracture area is protected from acid attack by the viscous gel.

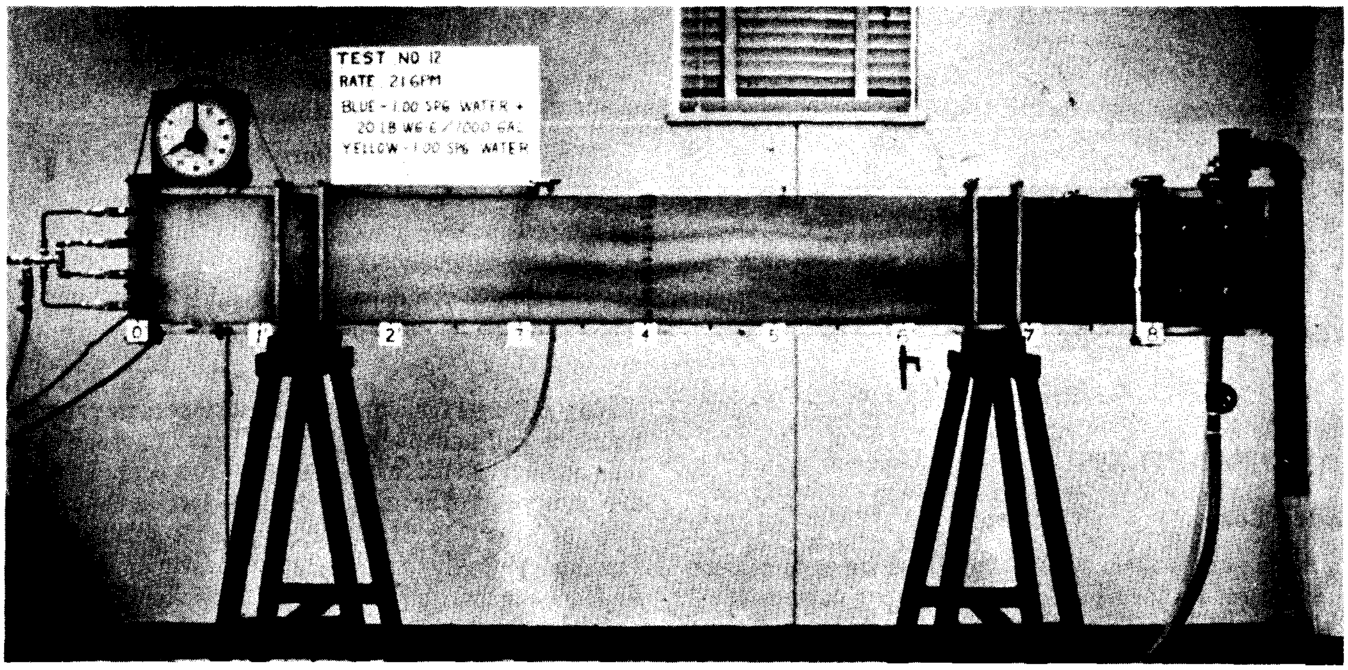

FIG. 4—THE DARKER AREAS IN THE MODEL CONTAIN THE VISCOUS PREFLUSH. THE LIGHTER AREAS CONTAIN THE NONVISCOUS FLUID. SOME VISCOUS FINGERING OCCURS, BUT THE VISCOUS FLUID IS WASHED OUT RAPIDLY, INDICATING INADEQUATE VISCOSITY OF THE PREFLUSH.

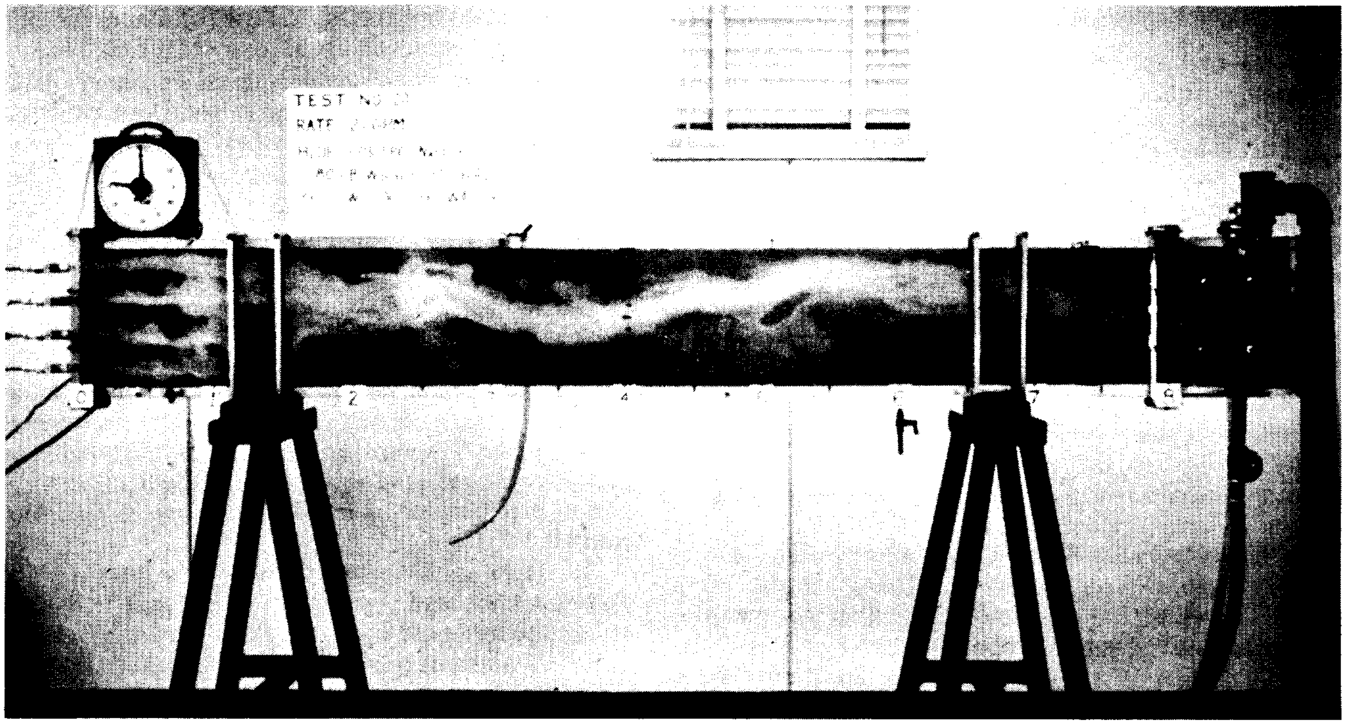

FIG. 5—THE PREFLUSH HAS ADEQUATE VISCOSITY UNDER THE CONDITIONS OF THE TEST, AND VISCOUS FINGERING OCCURRED.

TEST PROCEDURE

The flow tests were performed in a flow cell 1-ft high by 1/4-in. wide and 8-ft long. One side of the cell was aluminum, painted white, and the other side was clear plexiglass.

The inlet end (left) consisted of four 1/4-in. openings spaced evenly 1-1/2 in. from the top and bottom and 3 in. between, which flowed directly into the 1/4-in. width cell.

The outlet end (right) started at the 8-ft mark and was 1-ft high by 3/4 in. wide and 1-ft long. A 2-in. opening situated equidistant from the top and bottom carried the fluid up above the level of the cell, through a suction break and down to the drain.

The clock used was a standard timer clock operating counterclockwise. The face was renumbered to produce a total time reading interval. The long hand is the minute hand and the short hand is the second hand.

A peristaltic pump was used that flowed 2.1 gpm for the equivalent rate of 0.1 BPM/ft of fracture height.

TYPES OF VISCOUS FLUIDS

Because of the effects of temperature and shear on the apparent viscosities of fluids, no one system can be used to produce adequate viscosity for all conditions. The following types of systems have been used as viscous preflushes.

High Viscosity Fluids

Low-Temperature Fluids

Natural polymers, such as guar gum in concentrations in excess of 80 lb/1000 gal., have been used at fracture temperatures up to about 120°F.

The fracture temperature or fluid temperature within the fracture is highly dependent on the volumes and rates of previous fluid entry into the fracture system. This factor should be considered when selecting a viscous preflush.

Synthetic polymers can also be used in the same manner as natural polymers.

High-Temperature Fluids

Two-component polymer gels can be used for high temperature conditions.[6] These systems contain a polymer that hydrates rapidly to produce enough viscosity to suspend the second component. The second component is a retarded polymer which hydrates rapidly at elevated temperature. This type system can provide adequate viscosity up to about 350°F.

Ultra-High-Viscosity Fluids

There are conditions that require ultra-high-viscosity fluids. Ultra-high-viscosity fluids can create wider fractures and also produce greater vertical fracture height. This type fluid is most beneficial when very thick producing intervals are being treated. A viscous preflush could eliminate the use of diverting aids in some cases, and at least reduce the number of diverting stages. The ultra-high-viscosity fluid used as a preflush also aids in lowering fluid loss of the acid in naturally fractured reservoirs.

Crosslinked polymers have been used successfully to produce ultra-high-viscosity fluids.[7] The crosslinking of the polymer is controlled by chemical additives so it will not occur until it enters the fracture.

High viscosity emulsion systems have also been used successfully as viscous preflushes ahead of acid.[8] The emulsion systems may have economic advantages over some of the polymer systems.

TYPICAL JOB PROCEDURE AND RESULTS

The fracture is usually initiated with a nonviscous water preflush. This fluid may contain a fraction reducer, fluid-loss additive and a nonemulsifier. If the zone has an extremely high bottomhole temperature, the nonviscous preflush may also be used as a cooling preflush. In this case, the quantity of water used may be relatively large.

The viscous preflush is injected next. The type viscous preflush used will depend upon the well conditions. Such things as bottomhole temperature, zone thickness and degree of natural fractures and type production influence the choice of viscous preflush.

The acid is injected following the viscous preflush. The type acid used can vary depending upon well and formation conditions. The acid may contain a friction reducer, a fluid-loss additive, a nonemulsifier and in some cases an anti-sludging compound.

The acid is followed by a water preflush to displace the acid away from the well to better utilize the last acid injected. The overflush usually contains a small quantity of nonemulsifier and a friction reducer.

Some job results of fracture acidizing treatments employing a viscous preflush are given in Table 2.

TABLE 2—JOB RESULTS OF FRACTURE ACIDIZING TREATMENTS USING A VISCOUS PREFLUSH

Formation	Field	Acid Type	Viscous Pad Type	Production Before Treatment BOPD	Production Before Treatment BWPD	Production After Treatment BOPD	Production After Treatment BWPD	Remarks
San Andres	Levelland	20% NEA*	Emulsion	75	31	126	50	
San Andres	Levelland	20% NEA	Emulsion	38	24	71	53	
San Andres	Levelland	20% NEA	Emulsion	22	3	31	5	
San Andres	Levelland	20% NEA	Emulsion	92	16	125	31	
Grayburg-San Andres	N. Cowden	20% CRA**	MY-T-GEL	17	2	46	15	
Grayburg-San Andres	N. Cowden	20% CRA	MY-T-GEL	8	2	52	43	
Grayburg-San Andres	N. Cowden	20% CRA	MY-T-GEL	29	12	24	73	
Grayburg-San Andres	N. Cowden	20% CRA	MY-T-GEL	0	0	42	61	
San Andres	Wasson	20% NEA	Emulsion	New		76	--	
San Andres	Wasson	20% NEA	Emulsion	New		40	--	
Glorieta	N. Vacuum	20% NEA	MY-T-GEL	1	--	88	--	
Abo	Empire	28% NEA	MY-T-GEL	New		125	--	Increase from 30 BOPD swab
Wolfcamp	Coyanosa	28% NEA	MY-T-GEL	133	576 MCF	418	2500 MCF	
Wolfcamp	Coyanosa	28% NEA	MY-T-GEL	21	--	26	--	(300 MCF gas)
Wolfcamp	Vealmoor	28% NEA	MY-T-GEL	New		60	--	
Penn	N. Bagley	20% CRA	MY-T-GEL	48	58	91	85	
Penn	N. Bagley	MOD 202***	MY-T-GEL	New		85	93	(Non-commercial on log)
Penn	N. Bagley	MOD 202	Emulsion	181	60	272	112	
Devonian	Magutex	20% CRA	Emulsion	93	2	164	80	
Devonian	Bagley	20% CRA	Emulsion	60	300	91	315	(Test is questionable)
Fusselman	McCormick	MOD 202	MY-T-GEL	3	21	54	20	
Fusselman	Amacker	28% NEA	MY-T-GEL	0	0	97	43	GOR 10,258:1
Ellenburger	Gomez	92-8****	Gelled Water	New		8200 MCF	--	
Ellenburger	Gomez	92-8	Gelled Water	New		17800 MCF	--	
Buda	----	28% NEA	MY-T-GEL	10	--	28	120	
Buda	----	28% NEA	MY-T-GEL	30	--	500	--	
Smackover	----	MOD 202	MY-T-GEL	200	--	500	--	
Glenrose	----	28% NEA	MY-T-GEL	140	--	250	--	
Edwards	----	28% NEA	MY-T-GEL	Trace	--	40	--	

*NEA - Non-emulsifying Acid
**CRA - Chemically Retarded Acid
***MOD 202 - Mixture of hydrochloric acid and acetic acid
****92-8 - 92% HCl and 8% Formic Acid

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