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PRACTICAL ASPECTS OF FOAM FRACTURING IN THE DEVONIAN SHALE

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ABSTRACT

Available data on foam frac treatments from DOE/industry cooperative ventures and the state-of-the-art in the formulation of foam fluids for hydraulically fracturing the Devonian shale are reviewed and discussed in light of an engineering measurement of factors affecting cleanup, induced geometry, production and cost. The benefits and limitations of foam as the fracturing fluid for the Devonian shale are discussed and evidence supporting the observations are exhibited. Special laboratory studies on formation damage and fracture conductivity impairment associated with fracture treatments using water based fluids and foam are reviewed as well. Rationale for selection of parameters used in the development of foam frac designs are set forth and limitations affecting universal applicability of foam frac stimulations are identified.

Results of early well life production rates are reviewed in light of necessary costs for achievement of the limited foam frac stimulations conducted. Overall, these treatments appear to be quite suited for the Devonian shale since the formation is shallow, exists at a low temperature and is composed of a low permeability rock that requires minimal contact time with fracturing fluids to avoid being damaged and to preclude interference with gas production from the native fracture system. Prospects for development wherein foam fracturing may be likely to succeed in linking the reservoir capacity with the wellbore are identified based on the stress ratio concept.

INTRODUCTION

A recent innovation in the developing of hydraulic fracturing is the use of foam as a low-residual fracturing fluid. The fracturing fluid is composed of water, a foaming agent, and nitrogen that form a homogenous gas-in-water emulsion when mixed at predetermined rates. Depending upon the quality of the emulsion, foam displays either Newtonian or Bingham plastic behavior and is a high viscosity fluid as well as an efficient fluid[1,2]. The effective efficiency and viscosity of foam generate large surface area and good proppant placement with low injection rates. Moreover, the low volume of water required to compose the foam minimizes the amount of fracturing liquid exposed to the formation. The low liquid content is quickly returned to the surface by expansion of the nitrogen during flowback.

References and illustrations at end of paper.

The properties that make foam ideal as a fracturing fluid in the water sensitive, low-pressure, low gas volume Devonian shale formation include the high efficiency due to low fluid loss coefficients, negligible sand-settling velocities, low friction loss in pipe, and high viscosity inside the induced fracture[3,4]. In addition, the absence of chemical fluid loss additives to control leak off during treatment leaves both the formation face and proppant bed relatively clean. Accordingly, foam seems to fit the definition of a desirable fracturing fluid since it can hydraulically create a fracture, it can carry sand into the fracture, it minimizes formation permeability damage, and it cleans up quickly after the job.

Foam has been used quite widely in the oil and gas industry for the past five years[5,6,7]. However, the advent of foam fracturing into the Devonian shale evolved from the Department of Energy research at Morgantown Energy Technology Center (METC) that was started in 1975 and was directed at improving gas productivity from new shale wells[8,9]. Together with independent gas producers and in cost sharing contracts with Kentucky West Virginia Gas Co., Consolidated Gas Co., and Columbia Gas System, DOE-METC has tested the effectiveness of both conventional-size foam treatments and large-volume treatments in stimulating gas production from different stratigraphic units within the Devonian shale formation. Although replicated tests are only available to arrive at a statistically-derived conclusion of the foam fracturing concept in one geologically similar area, sufficient data has been accumulated to indicate a trend. This paper addresses the experimental approach used to test foam as a fracturing fluid, describes the laboratory results guiding the design of stimulations, summarizes the fracturing treatment characteristics, as well as early time performance of shale wells fractured with foam in the DOE program, and identifies the limitations affecting future applications in the Devonian shale formation.

EXPERIMENTAL APPROACH TO THE EVALUATION OF FOAM FRACTURING

The main effects to be examined in the assessment of foam fracturing for the shale formations were regarded as the following:

1. How is the formation permeability affected by foam?
2. Can sufficient fracture conductivity be established to permit gas transport?
3. Can foam effectively place proppants within the induced fracture?
4. What is the projected extent of the induced fracture?

In addressing these factors, there are several important characteristics of foam fracturing that should be identified and discussed. Basically, the fracturing fluid exhibits a low friction loss in the pipe, a high viscosity in the fracture, a negligible sand-settling velocity, and a low fluid loss coefficient[10]. All of these factors contribute to the judgement of foam as a highly-efficient fracturing fluid. Coupled with the observations that only 25 percent of the fracturing fluid volume displaced is water, and that foam has minimal wetting and formation invasion characteristics, it is important to note that these factors influence minimal liquid retention by the formation and rapid cleanup of the wellbore following fracturing[11,12,13].

The degree to which the foam fracturing process can be efficiently employed to extract gas from the Devonian shale is addressed in the following research.

SHALE-FLUID INTERACTION

The potential for possible formation and wellbore damage related to fracturing fluids prompted studies to investigate shale stability and permeability following contact with them. Selective sources who have worked with shale specimens indicated that shale disintegrates when it dries following contact with fluid whereas other's claims indicated that shale becomes unstable if it absorbs moisture[14]. As a screening approach to assess the potential impact that selected fracturing fluids might have, Chenevert and Associates measured the degree of core swelling that occurred in shale specimens of both organic-rich and organic-lean intervals upon contact with water, kerosene, and five other solutions of water-based fluids containing chemicals for two shale cores (that is, a year-old core from West Virginia and a freshly-cut core from Virginia). Typical response for an organic-lean section of shale is shown in Figure 1. In these laboratory tests at room temperature conditions and atmospheric pressure, the volumetric expansion of core plugs (½-inch diameter x 1-inch long) were measured by strain gauges affixed to the specimens following contact of the specimen with the test fluids for ten hours. Relative vapor pressure and water adsorption were measured on the test specimens to remove the effects of the environment from the measurements in final analysis of the expansion data. The results on both year-old specimens and freshly-cut specimens from both organic rich and organic-lean stratigraphic intervals produced the following observations:

Effect of various fluids on shale

1. Kerosene causes no appreciable swelling in shale (i.e., = .005 percent).
2. Freshwater induced practically no increase in swelling in organic-rich specimens (i.e., .05 percent) and considerable swelling in organic-lean specimens (i.e., .15-.70 percent). This is illustrated in Table 1.
3. A 2-percent KCl solution helped to reduce swelling in some organic-lean intervals.
4. X-ray diffraction and water adsorption isotherm data show these shale specimens to contain only the slightly-swelling clays of illite and chlorite. No montmorillonite was found in the specimens.

The predominant presence of illite and chlorite plus the swelling tendency of the organic-lean shale interval suggest that the introduction of fracturing fluids into such formations must be treated by a solution of 2 percent KCl. The test data also shows that the organic-rich shale intervals are not affected by water or water-based fluids such as foam. This is thought to be the result of a protective organic coating and/or more effective organic cementing agent. Limited data[15] from the Mound Lab facility of Monsanto Corp. support the findings of Chenevert.

Complementing this study, a laboratory testing was conducted on the foam stability of the medium as a function of surfactant concentration and the degree of flow rate reduction that results when a stable foam is injected into the formation such as shale. Observations evolving from this short test series are shown in Table 2. Results indicate that a surfactant concentration of 5 gal/1,000 produces a stable foam and that the injection of this foam through a fractured shale specimen does not reduce the established flow rate.

FRACTURE CONDUCTIVITY

The goal of every induced hydraulic fracture is to achieve a conduit from the wellbore to the reservoir that exhibits little or no obstruction to the flow of gas over the created path. Accordingly, laboratory tests were conducted on shale specimens subjected to confining stresses representative of in situ conditions to determine: (1) if proppants are needed for establishing sufficient flow conductivity in shale reservoirs and, (2) if the water-based fracturing fluids are detrimental to the sustained performance of efficiently-propped fracture. The test designs and laboratory results are the work of Terra Tek[16].

Proppant Size vs. Closure Pressure

Specimens for the tests were obtained from the Devonian shale formation in Lincoln Co., West Virginia and Martin Co., Kentucky. As an approach in the investigation of the importance of proppants, core specimens were saw cut and fitted back together without any proppants. In the test, nitrogen is flowed through the test specimen that is subjected to confining pressure ranging from 1,000 to 4,000 psi. For the stated closure stresses and for dry nitrogen injection pressures up to 100 psi, the fracture conductivity ranged from 1 md-cm to about 300 md-cm (Figure 2). Visual examination of the faces of the samples after the test found only small contact marks. There was no visible plastic flow or imbedment. Petroleum engineering calculations for the extremely small formation permeability (1 µdarcy) and for 40-acre spacing indicate that a minimum value of 250 md-cm is required for sufficient fracture conductivity. Referring to the data, this capacity exists only for a closure pressure of 1,000 psi in the shale. An assessment of lateral stresses in various areas in the Appalachian Basin indicate that this is an exception rather than the rule, because regions of minimum closure stress occur only in geologically-complex areas where basement faulting has created a naturally-fractured reservoir. Accordingly, induced fracturing without proppant implacement will establish a predictable fracture conductivity that is insufficient to achieve the flow rates required for a shale gas well.

Shale specimens that were saw cut and propped with .56161 ft^2 of 100 mesh and subjected to closure pressures of 1,000 to 4,000 psi experienced little decline in a fracture conductivity of 1,100 md-cm. This test indicates that, if the formation does not experience imbedment, a proppant layer of 100 mesh is sufficient to establish a fracture conductivity characteristic of unrestricted gas flow. Specimens propped with 1.44 lb/ft^2 of 20/40 sand did not crush under simulated downhole stress conditions and exhibited a fracture conductivity of approximately 8,000 md-cm. The results of the unpropped fracture and for the fracture propped with 100 mesh sand and also 20/40 sand are shown in Figure 2.

Effect of Fluid and Closure Pressure

As an approach to ascertain if water-based fracturing fluids are detrimental to the sustained performance of efficiently-propped fractures, core specimens were saw cut and propped with a sand concentration of .027 lb/ft^2. Initially, the cores were subjected to confining pressure of 90 psi for the proppants to settle in place. By flowing dry nitrogen gas through the propped channel, conductivity measurements were taken. The change in fracture conductivity with effective pressure was determined by varying the confining pressure from 500 psi to 3,500 psi; in all cases, gas injection pressure within the fracture was maintained at 300 psi. Cantilevers were placed on the outer core surface to monitor changes in fracture and closure. Fracturing fluid was subsequently flowed through the propped fracture for four hours to simulate field-fracturing time and the change in fracture conductivity with conductivity with effective pressure was determined for the same confining pressure range.

Results of fracture conductivity variation on organic-rich shale specimens after contact with fracturing fluids of foam, a water-base fracturing fluid containing a surface-tension reducer and clay stabilizer, and a water-base fracturing fluid containing only a surface-tension reducer are shown in Figure 3. Each of the fracturing fluids affected a reduction in fracture conductivity over the entire range of confining pressures with foam exhibiting little or no reduction at any pressure level. The minimum wetting nature of the foam is believed to be the factor contributing to minimal reduction in fracture conductivity and, of course, is a factor favoring the use of foam as a fracturing fluid.

PROJECTED FRACTURE GEOMETRY

The Devonian shale wells in which foam treatments were performed were first stimulated with approximate rates and volumes using properties assessed by the service companies for these treatments. The Perkins and Kern type calculations for the six conventional foam fracturing treatments conducted by DOE with cooperating independent producers are shown in Table 3. Projected fracture lengths range from 300 to 600 ft for half wing depending on the perforated height interval selected in the design. Production after fracturing is not directly correlative with the projected propped length because of varying reservoir capacity. This observation suggests that more information is required to locate areas of increased reservoir capacity where it is believed that small fracture lengths could be effective in augmenting production. Alternately, the method of projecting propped length may not be appropriately describing the effects of the foam treatment.

The sensitivity of the projections indicated that the property of fluid loss coefficient is the most important. The most recent investigations indicate that 10^{-1} to 10^{-4} $ft/\sqrt{min}$ covers the probable range[17,18]. The behavior of viscosity of the foam is felt to be significant to the effective length of the fracture and the width to length rates of the fracture which determines allowable sand volume.

Increases in injection rate influence directly the size of the fracture because more fluid is put into the fracture in a given time period. This decreases foam viscosity and increases fluid leakoff so that a careful study of all effects is required. On small volume treatments, frac height is closely approximated by the perforated interval but is influenced by bottomhole treating pressure and stress level in the stratigraphic interval and surrounding beds.

Containment of the vertical growth of an induced hydraulic fracture to predominantly the pay zone is dependent on (1) the contrast between the physical properties of the pay zone and the boundary layers, (2) the physical properties of the barrier interface and, (3) the fracturing fluid properties[19].

Induced hydraulic fractures in a pay zone located between two adjacent barrier layers tend to be contained, provided the stiffness of the pay zone is less than the stiffness of the barrier layers[20,21]. In a layered formation such as the Devonian shale, the separate layer stiffness is reflected in the measurable parameter called fracture toughness that represents the resistance of the rock to fracturing. The separate layers may also experience different lateral stresses as a result of past tectonic activity. Fracture containment analysis is accomplished by evaluating these factors as they apply to the particular zone being stimulated. In the Devonian shale stratigraphic column, this interval is usually the organic-rich section called the Lower Huron or Middle Brown Shale. Fracture toughness data for this pay zone is less than that of the boundary layers by 740 psi $\sqrt{in}$. The immediate implication of this is that vertical fracture height can be contained.

Difference in in situ lateral stresses between the pay zone and the barrier layers also has a distinct influence on fracture propagation and containment[22,23]. The distance a crack will advance into a higher stress bounding layer in terms of the pressure within the fracture is illustrated in Figure 4. Here, it is shown how far an induced fracture will advance into a layer of high lateral stress (the barrier layers) in terms of the pressure (P) within the fracture and the fracture fluid pressure (P_0) required for the fracture to reach the interface. The curve shown was developed for the Lower Huron member of the Devonian shale and is applicable for a perforated interval of 250 ft, a fracture toughness of 740 psi $\sqrt{in}$ and a parametric value of the lateral in situ stress difference (S_2-S_1). This would mean that when a stress difference of 700 psi was measured between the barrier layers, containment of the vertical fracture growth to 50 ft in the barrier layer can be achieved by controlling the bottomhole treating pressure (BHTP) that extends the induced fracture to less than 400 psi above the minimum stress that tends to close the crack. Hence, fracture design for barrier containment is feasible. Finally, if the in situ stress in the barrier layers were less than the in situ stress in the pay zone which is the case for the Upper Huron (Upper Brown) member of the Devonian shale, a situation would exist where it requires less pressure to propagate the fracture in the barrier than in the pay zone.

Recent investigations have considered the effect of interface bonding and its effect on containment of hydraulically induced fractures. The strength of the interface between adjacent formations has been shown theoretically to be an important factor in containment[24]. With weak bonding, fracture containment is possible and is associated with slippage at the interface. If the shear strength is large, the induced fracture can propagate past the interface. The effect of interface roughness on fracture growth across the interface has been experimentally investigated using unbounded interfaces in limestone and sandstone but the results showed very little effect on fracture containment[25].

EFFECTIVENESS OF FOAM FRACTURING

Exploitation of the Devonian shale by hydraulic fracturing and the importance of induced geometry and efficiency of extraction in improving gas deliverability is still in the evaluation mode. To date there are less than 200 induced hydraulic fractures in the Devonian shale formation with foam having been used in an estimated 10-15 percent of the wells. The geologic nature of the resource is such that the host rock has only about 1 μdarcy of matrix permeability to transmit gas. The problem is one of interconnecting numerous natural fractures in a stratigraphic interval of interest which are considered essential to the establishment of a commercial well. The productivity of Devonian shale wells depends on the density of the natural fracture system, the richness of the organic source and the effectiveness of its interconnection with the wellbore.

The effectiveness of projected fracture length on produced gas from a shale reservoir can only be inferred from a statistical comparison of production from borehole shot wells and hydraulically fractured wells in the same gas field. A comprehensive analysis of 18 hydraulically fractured wells and 35 borehole shot wells was made by Yost[26] for the Eastern Kentucky gas field. It was observed in the data that initial open flow rates were not always indicative of increased performance but the decline rates were indicative of better performance. In particular, decline rates of conventional size hydraulically fractured wells exceeded 70 MCFD at the end of the first producing year whereas the borehole shot well production was 35 MCFD. Furthermore, the distinct separation in decline curves from 1 to 5 years of production indicated that the cumulative production of hydraulically fractured wells (113 MMCF) exceeded that of borehole shot wells (60 MMCF) by 53 MMCF. This suggests that an increased number of gas filled microfractures are interconnected through hydraulic fracturing as a result of the longer effective wellbore radius. The net result is one of increased deliverability by a factor of 2 to 1 in the first 5 years and projected additional reserves of 200 MMCF after 30 years of cumulative production[27].

Field data from both conventional sized treatments (~1000 bbls) and MHF treatments (3000-6000 bbls) have been accumulated by the Department of Energy in cooperative projects with Columbia Gas and independent gas producers in the East[28]. Treatment volume and projected lengths are shown in Table 4. Treated intervals included both the Upper and Lower Huron in the Kentucky and West Virginia shale wells of the Appalachian Basin, the New Albany Shale well in the Illinois Basin and the Antrim shale of the Michigan Basin. These data are extremely limited and can only be used for trend forecasting, perhaps; accordingly, the following observations are offered:

Conventional Treatments

1. Foam fracturing in the New Albany shale failed because the well was plagued with the loss of the energy assist medium (nitrogen) into the fractured formation before complete flowback occurred.

2. Foam fracturing in the Antrim shale was able to stimulate gas production in a step out well that was several miles away from the producing gas field. A substantial water influx of 44 bbl/day accompanied the production.

3. Seven of eight foam fracturing treatments conducted in a province of similar geologic disturbance in Eastern Kentucky and Western West Virginia had initial open flow rates ranging from 103 to 730 MCFD with the mean value being 388 MCFD. Data represented were developed by DOE and Columbia Gas independently.

MHF Treatments

Investigation of large volume treatments using foam as the fracturing fluid were completed by Columbia Gas in cooperation with the Department of Energy[29]. During the course of the cooperative program, ten operationally successful massive hydraulic fracture treatments were performed in four stratigraphic intervals of the Devonian shale formation. The tests were conducted in a 3-well farmout area in Lincoln Co., West Virginia within an established gas producing region containing 75 old wells.

In well no. 20403 at the test site, each of the four MHF treatments used foam as the fracturing medium to reduce potential cleanup problems in this low pressure (250 psi) reservoir by taking advantage of the foam's energy assist mechanism. Each treatment design called for 1000 gallons of foam to be injected for each foot of perforated interval so that a comparative analysis of stratigraphic interval production potential could be made. The test intervals and the results of flow tests after stimulation are shown in Figure 5 for well no. 20403 and adjacent test wells. Post frac flow rates for four different perforated intervals were 110, 200, 107, and 160 MCFD, respectively. Results of pre and post fracture reservoir engineering well tests are summarized in Table 5.

As an alternative to the use of foam entirely, smaller perforated intervals of the same stratigraphic sections were stimulated with nearly equal volumes of foam and water in three of four available pay zones in the shale well no. 20401. These treatments utilized foam as a spearhead and gelled water as the fracturing medium. Results of Zones 2, 3, and 4 were 111, 80, and 21, respectively (Figure 5). A direct comparison of these zones to similar zones in well 20403 shows foam to be a better fracturing fluid. In this low pressure reservoir, the foam success was probably due to its greater efficiency in fluid recovery following fracturing since all other factors appear to be similar to the first well (table 5).

An attempt at optimizing well performance utilizing effective volumes of foam in only two intervals was the objective of the tests in well 20402 (Table 5, Figure 5). Post frac open flows of 145 MCFD and 139 MCFD were measured for Zone 1 and Zone 2, respectively. The sum of these values were taken to represent the wells total potential (i.e. 284 MCFD).

LIMITATIONS OF FOAM FRACTURING

Even with the good attributes of rapid cleanup, minimal formation damage and low treating pressures, there are definite limits to the use of foam fluids in hydraulic fracturing treatments[31]. Foams are basically non-wall building fluids and are held in the fracture by the effective viscosity of the foam. King[32] and Daneshy[33] report in conversations that foam fluids do not exhibit the fluid loss attributed by the inventor. While liquid leakoff may be low, total liquid and gas leakoff may be high. So foams are only good fracturing fluids if the treating pressure and differential pressure into the formation is low and if the formation permeability is low (e.g. 1 md or less).

Foam leakoff will probably be very high due to the high shear rates associated with the foam leaking into a tiny crack. The best wells in the Devonian shale will have an abundance of microcracks or native microfractures so the use of 100 mesh sand is recommended to reduce leakoff of the foam. It will not stop leakoff but it will slow it down without requiring chemical additives which could seal off the permeable microfractures that constitute the gas flow paths.

Foam is limited to reservoir environments less than 150°F because chemical reactions and surfactant adsorption are affected at the higher temperatures and the foam becomes unstable.

Sand concentrations of foam designs are limited because the proppant is added to the water phase and this phase is only ¼ of the total foam fluid volume. Therefore, when pumping at low rates (e.g. 5 BPM-water), it may be necessary to circulate between the frac pump and the blender at a much higher rate. This will maintain adequate agitation in the blender and high flow rates through the circulating hoses to carry high proppant concentrations in ungelled water[34].

Once the fracture is created, foam does not allow the sand to settle, therefore, the dynamic width of the fracture closes on the sand to make a narrow fracture channel[35]. This channel only remains an effective conduit if the proppant is not imbedded into the fracture wall. Accordingly, the nonwetting nature of the foam is an advantage in avoiding formation softening.

Nitrogen requirements for the creation of foam are directly related to the treating pressure necessary for fracture extension. This requirement increases exponentially with pressure. Foam fracturing can play a major role in stimulating the Devonian shale until the treating pressure required exceeds 3000 psi where the incremental nitrogen costs begin to exceed reasonable investments. Typically, bottomhole treating pressures will range from 500 to 2500 psi in the Devonian shale. The pressure required for successful execution can be predicted beforehand if a measure of instantaneous shut-in pressure following breakdown and the displacement of acid can be obtained. If this value permits the treatment pressure to be less than 3000 psi, then foam fracturing can be effectively executed[36].

Costs associated with foam fracturing are somewhat higher ($3000) than gelled water fracturing for conventional size treatments and such investments become larger whenever MHF type designs are considered (Table 6). However, experience has shown that foam fracturing has reduced the amount of service rig time to swab and bail fracturing fluid from the wellbore and has also reduced water haulage and storage costs. These reduced costs plus the benefits of the foam medium should justify the required investment.

Finally, foam fracturing might only be worthwhile in areas where the shale has been established as a gas bearing reservoir. In the development of prospective areas of suspected reservoir capacity to warrant stimulation of some part of the Devonian shale, it appears that the significant variable controlling production is a porous fracture facies within the Huron stratigraphic member. The preferred interpretation of several working hypothesis is that the fracture facies relates to tectonic shortening across the shales which is apparently induced by minor flexing of the shale over basement faults[37]. Correlation of historical production with the factor of stress ratio (that is, ratio of minimum horizontal stress to overburden stress) indicates that a regional mapping of this factor could provide prospective areas for development where shale gas might be commercially exploited. Where the stratigraphic interval of increased fracture density is breached or sealed above the porous zone, high producing wells should be achieved. If the fractured interval is not sealed, then gas should escape to the surface and the productive trend should be abnormally low.

In Figure 6, favorable productive trends have been shown to be correlatable with areas where the stress ratio factor is 0.3 to 0.5. The implication is one that such an area would have a high fracture density and, as a result, a reservoir of sufficient capacity to sustain production from a stratigically located wellbore. Regions of low fracture density or limited reservoir capacity are thought to exist in areas having stress ratio values of 0.6 to 0.8. In such regions, MHF foam treatments may be required. In the former, it may be inferred that basement faults have induced significant flexure to create a reservoir. In the latter, it may be inferred that basement faults were not accompanied by much flexure. In regions characterized as having stress ratios of 0.9 or above, the absence of any reservoir capacity would preclude any chance of producing shale gas.

CONCLUSIONS

Overall, foam fracturing appears to be quite suitable for the Devonian shale since the formation is shallow and has low temperature (less than 150°F) and low permeability (~1 µdarcy). Stable foams can be created to control fluid leakoff and to carry proppants without being detrimental to the formation permeability. The nonwetting nature of the foam precludes formation softening and subsequent proppant imbedment in the organic-rich shale intervals which are the targets for stimulation. Proppants are absolutely necessary to sustain fracture conductivity in the shale reservoir. However, sand concentrations are currently limited by mechanics to a 1 lb/gal density.

Fracture mechanics research indicate that the only chance for containment of fracture growth vertically lies with the selection of the Lower Huron member as the stimulated interval. In order to accomplish this, the bottomhole treating pressure must be less than 400 psi above that pressure required to initiate propagation.

A thorough examination of the Eastern Kentucky and Western West Virginia producing areas show that hydraulically fractured wells are a definite improvement over borehole shot wells in gas deliverability and projected reserves. Pilot tests of conventional foam fracturing treatments exhibited initial open flow potentials that averaged 388 MCFD. Pilot tests of the massive hydraulic fracturing concept using foam showed that higher deliverability rates from the Lower Huron shale member may be achievable. However, replicated experiments of a single stage large volume treatment in a given geologic area are required before any conclusions can be offered. Prospects for development wherein sufficient reservoir capacity exists to be exploited by the hydraulic fracturing foam process can be inferred from geographic documentation of the lateral to vertical stress ratio.

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TABLE 1

WATER-SHALE, SWELLING RESULTS

Columbia Gas Well (Fresh Core), Wise County, West Virginia

Depth Feet	Type	% Swelling After 10 Hours
4917	Organic Lean	.175
4933	Organic Lean	.15
5300	Organic Lean	.65
5369	Organic Rich	.05

Columbia Gas Well (Year Old Core), Lincoln County, West Virginia

Depth Feet	Type	% Swelling After 10 Hours
2740	Organic Lean	.70
2763	Organic Lean	.30
3007	Organic Lean	.70
3027	Organic Lean	.40
3458	Organic Rich	.08
3896	Organic Rich	.08

TABLE 2

FOAM STABILITY TEST

Concentration gal./1000	Volume (cc)	Time to Break to 50cc liquid (sec)	Vol. After 10 min. (cc)
2	280	181.8	230
5	410	355	370
10	430	352.2	380

CORE FLOW TEST

Surfactant Solution	Percent Improvement
5 gal./1000 in 2% KCl water	6.20
2 gal./1000 in 2% KCl water	5.97

TABLE 3

PROJECTED FRACTURE LENGTHS FOR FOAM TREATMENTS

State/CO	Frac Ht (ft)	Viscosity (cp)	Volume* (gal)	Rate (BPM)	Prop Length (ft)	Production (Before/After)
KY/Perry	100	500	40,000	30	435	0/60
KY/Perry	100	500	50,000	25	475	0/350
KY/Christian	150	500	45,000	25	240	0/15
KY/Perry	80	500	50,000	25	581	0/103
MI/Ostego	72	100	46,000	25	691	0/150
WV/Mason	190	500	50,000	25	278	0/350

* Sand density @l lb/gal

TABLE 4

FOAM FRACTURING TREATMENT DESIGNS

Volume (bbl)	1,000	3,000	5,000
Foam Rate (bpm)	40	40	40
N_2 (SCF)	572,000	1,740,000	2,922,000
N_2 Rate (SCF/min)	23,100	23,100	23,100
Water (Gal)	12,500	37,900	63,700
Water Rate (bpm)	12	12	12
Sand (lbs)	26,900	62,200	222,000
KCl (sacks)	21	63	106
Surfactant (gal)	37	83	192
Hydraulic Horsepower	800	800	800
Productivity Increase	6	6.6	7.4
Fracture Extension (ft)	300	500	900

Note: All jobs are staged using ball sealers and/or diverting agents.

TABLE 5

COMPARISON OF RESERVOIR PARAMETERS[1]
AND PRODUCTION DATA
WELLS NO. 20403 AND 20401

	20403					20401				
	k md.	S	$2X_f$ ft.	P_{ext} psig	I.O.F. Mcfd	k md.	S	$2X_f$ ft.	P_{ext} psig	I.O.F. Mcfd
Zone 1										
Pre-Frac	No Test				Show	No Test				Show
Post-Frac	.05-.10			321	110	.02-.05	-4.08 to -4.43	50-70	266	110
Zone 2										
Pre-Frac	.03-.11	-4.10 to -4.30	72-86	269	95	No Test				Show
Post-Frac	.04-.13	-4.75 to -4.90	136-156	245	200	.07-.14	-3.63 to -3.98	32-46	252	111
Zone 3										
Pre-Frac	No Test				103	No Test				Show
Post-Frac	.05	-3.68	46	265	107	.03-.06	-4.28 to -4.62	66-94	258	80
Zone 4										
Pre-Frac	No Test				381	No Test				Show
Post-Frac	No Test				160	No Test				21
Average =	.07	-4.35	100	260[2]		.06	-4.17	60	259	

[1]Reservoir parameters based on Horner plot (buildup tests)
[2]Average of zones 2,3,4 pressure

TABLE 6

FOAM FRACTURING COSTS

	1,000 bbl.	2,000 bbl.	3,000 bbl.
Nitrogen*1	6,232	10,918	15,603
Sand	3,213	6,426	9,639
Surfactant	1,168	2,336	3,504
Proppant Handling	840	1,680	2,520
Pumping (Foam)	800	1,600	1,600
Ton - Mileage	630	1,260	1,890
Blender Charge	560	560	560
Mileage*2 and Delivery*3	300	537	712
Surfactant Pump	210	210	210
Clay Stabilization	204	408	612
	14,157	25,935	36,947

*1 Based on BHTP of 1200 psi

*2 Based on 100 miles

*3 Based on 10 hours

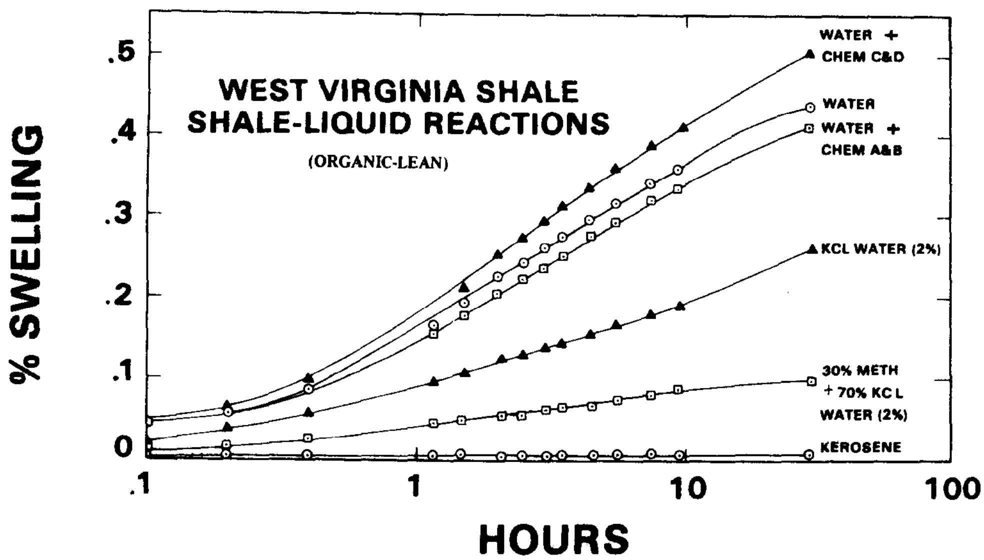

Fig. 1 - Swelling curves for the organic-lean section of West Virginia shale wells

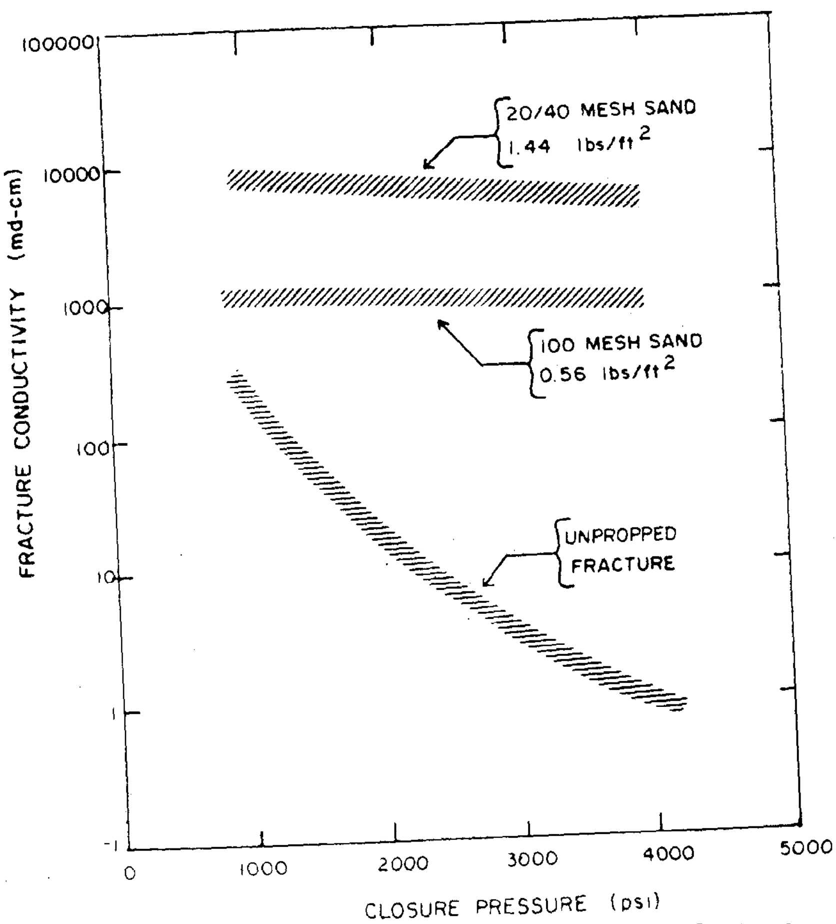

Fig. 2 - Fracture conductivity for unpropped and propped fractures.

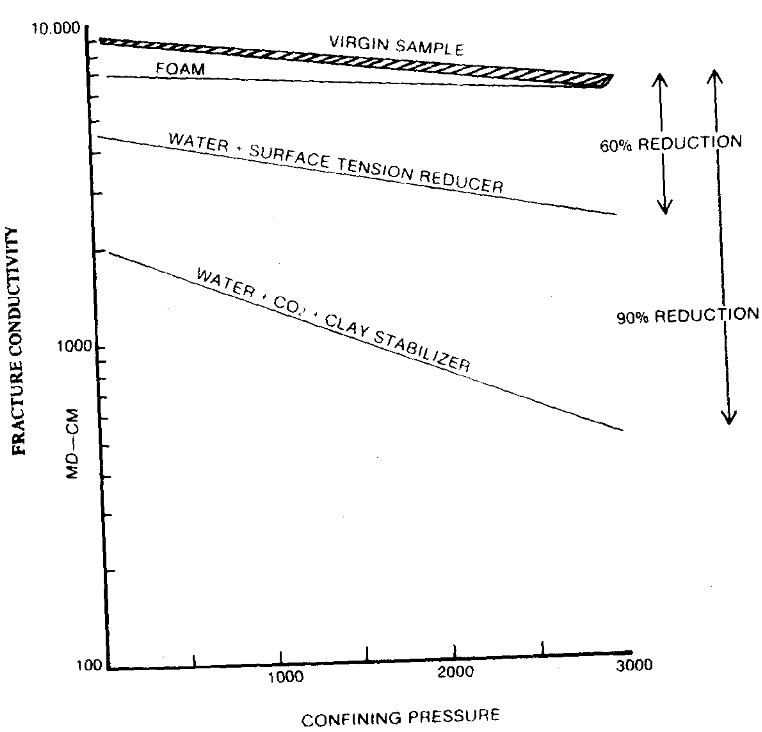

Fig. 3 - Fracture conductivity variation with closure pressure.

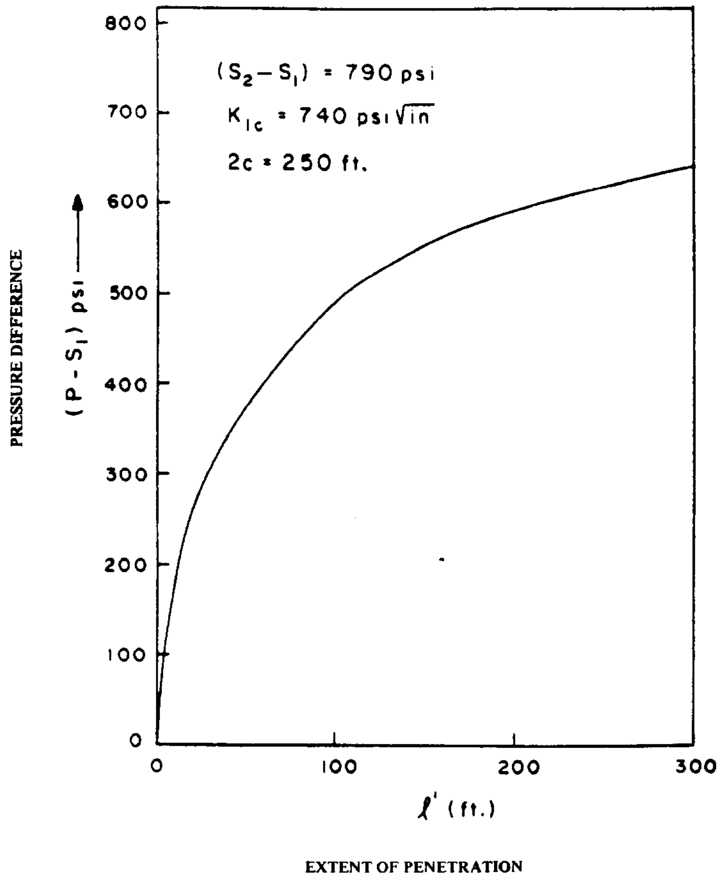

Fig. 4 - Fracture migration into containment layer.

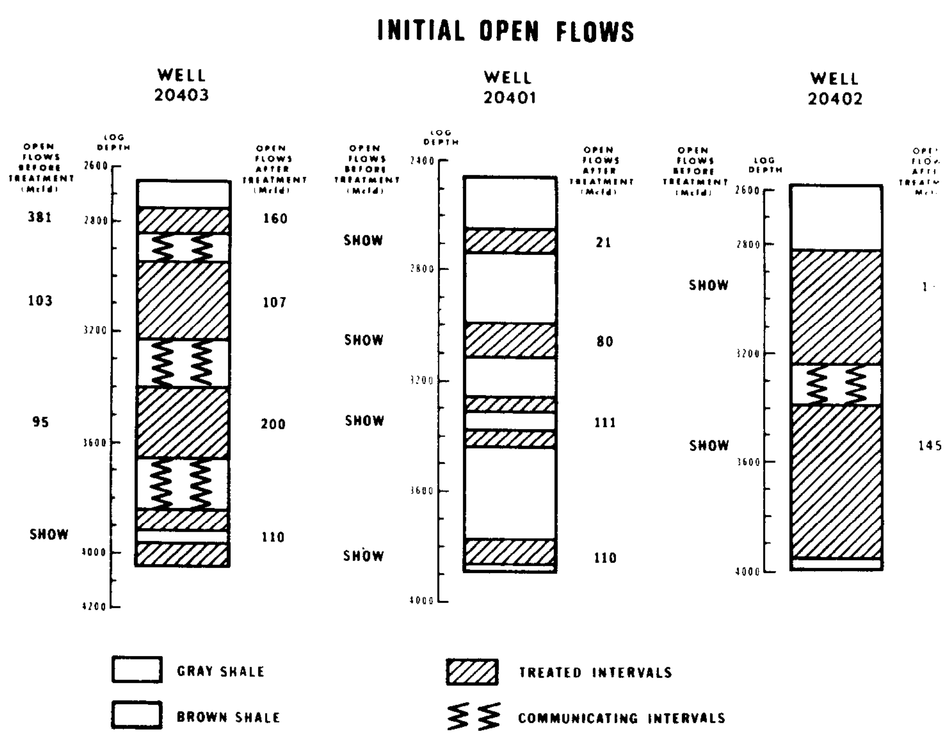

Fig. 5 - Initial open flows from MHF foam wells.

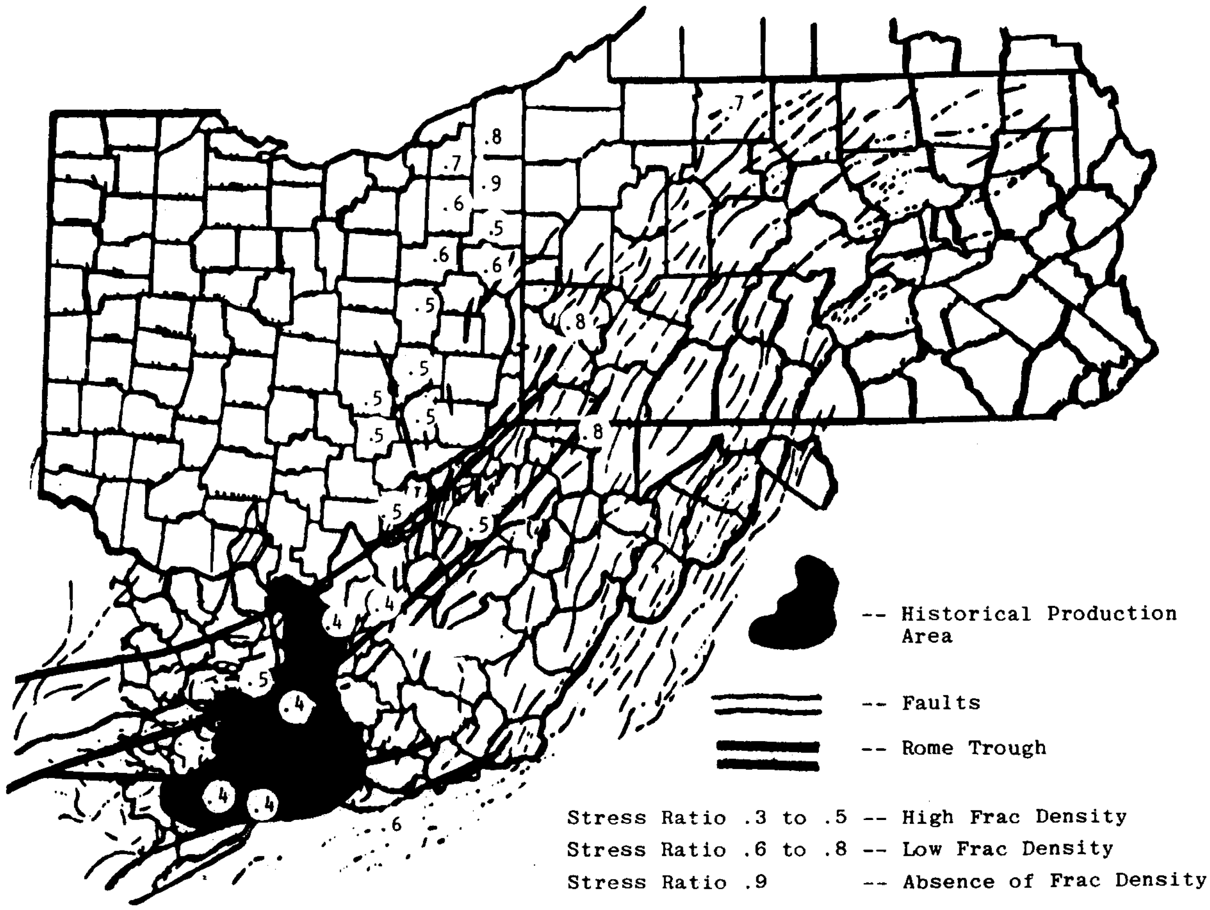

Fig. 6 - Areal variation of stress ratio and/or prospects for development.