FOAM FRACTURING: THEORIES, PROCEDURES AND RESULTS

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ABSTRACT

For the past several years, foam has been used in many treatments as a fracturing fluid. Although many different types of reservoirs have been stimulated with foam, the primary zones of interest in Eastern Kentucky and Southern West Virginia have been the Berea Sandstone and the Devonian Shales. Due to the nature of these formations, i.e. low permeability, low bottom-hole pressure and water sensitivity, foam fracturing has been a successful technique.

This paper presents the basic background theory of foam and presents several basic treatment designs which have been used successfully in the Devonian Shales and Berea Sandstone. Production histories for up to two years on a number of wells fractured with foam are compared to production histories of offset wells which were conventionally fractured with gelled water. In all the side-by-side comparisons, foam fracturing was found to give production results either as good as, or better than, conventional fracturing with gelled water.

INTRODUCTION

In the decade of the 1970's, foam fracturing was established as a tool for stimulating the production of hydrocarbons from low pressure, low permeability wells.[1,2] In the past several years, foam fracturing has also been applied to the Devonian Shales of West Virginia and Berea Sandstone of Eastern Kentucky for stimulating production of natural gas.[3,4]

The Devonian Shales typically have low natural reservoir pressure, with low permeability, natural fracturing, and tendencies toward fluid sensitivity and frac fluid retention.[5] Foam, as a fracturing fluid, has inherent advantages for use in the initial stimulation of such formations. But the real value of foam stimulation must be reflected in the hydrocarbon produced. This paper presents the results for foam fracturing treatments, as indicated by production histories up to two years, in comparison with the results of conventional gelled water fracturing treatments.

THEORY

A fracturing fluid often is a high viscosity fluid which is utilized to create a fracture and to transport propping agent and

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place it in the fracture. Efficient fracture extension requires good fluid loss control. For greatest production benefit, the frac fluid must cause minimal damage to the formation and then return to the surface with maximum efficiency.

Conventional aqueous fracturing fluid systems use gelling agents, such as polysaccharide gums, to yield fluids with high viscosity. The ability of the fluid to support proppant is partially dependent upon the concentration of the gelling agent in the fluid. High gelling agent concentrations also aid in fluid loss control; however, additional particulate fluid loss additives are often needed for full fracture extension. Return of the broken gelled water to the surface depends on various fluid properties as well as pressure within the reservoir. If the reservoir pressure is low, the return of fluid must be assisted by swabbing the well before the benefits of the frac treatment can be realized.

Foams, which are mixtures of a gas phase, a liquid phase and a surfactant, meet all the basic requirements for a good fracturing fluid; however, the fluid properties of foam are derived from a structure different from that found in gelled water.

The quality of a foam is defined as the volume of gas divided by the total volume of the foam. Generally, the higher the quality of a foam the higher its viscosity. The high apparent viscosity of foam is due to the interfacial structure of the foam bubbles. In very low quality foams, e.g. below 50 quality, the spherical gas bubbles have freedom to move with little restriction from adjacent bubbles. In foams above approximately 50 quality, the bubbles touch each other and allow less freedom of movement within the total fluid. In high quality foams, i.e. above 75 quality, the bubbles are crowded together and no longer have spherical shapes. Movement within the fluid is very restricted; hence, high apparent viscosity results.

In a static foam, liquid will drain from the fluid, and the foam that remains on top effectively increases in quality. As the quality of the foam increases, viscosity also increases as the bubbles distort from a spherical shape and the lamella assume a planar configuration.[6] Sand particles are held in place by the foam structure and do not readily settle through it. When the quality of the static foam increases, the structure becomes somewhat rigid, lending greater support to the sand.

Foams in the range of 65 to 80 quality are typically used in foam fracturing. So proppant is easily transported by the foam and then supported once the fracture has been created. As a result the proppant is more uniformly distributed within the fracture rather than simply allowed to settle to the bottom of the fracture.

Foam has been shown to have excellent fluid loss properties for low permeability formations.[7,8] In the absence of natural fractures, no fluid loss additives are required. In a highly naturally fractured area, a coarse fluid loss additive, such as 70/170 mesh sand, has been found to be helpful in bridging the natural fractures to allow extension of the created fracture.

Formation clays which are water sensitive can either expand to reduce permeability or migrate to block flow channels upon contact with water. Foam helps minimize water damage to the formation because of the overall low water content of the fluid. Additional clay protection can be achieved by the use of inorganic salts and polymeric clay stabilizers.[9] Oil or methanol foams can also be used for maximum protection of clays, if needed.

A major advantage of a foam fracturing fluid is its fluid recovery efficiency. When pressure is released at the wellhead, the low hydrostatic head in the wellbore presents lower resistance to production of the foam frac fluid than for a gelled water fluid. The compressible nature of foam also helps bring the liquid back due to expansion of the gas in its return to the wellbore. This gas expansion effect is most beneficial to wells with low formation pressure. The clean up of a foam fracturing treatment is usually accomplished with two days; whereas, a gelled water fracturing treatment may require several days.

FRACTURING TREATMENT DESIGNS

When fracturing treatments are performed successfully in a particular locality and formation, the treatment design generally becomes standardized for that area. Some of the formation parameters necessary for designing fracturing treatments in the West Virginia Devonian Shale and Kentucky Berea Sandstone are given in Table I.

The presence of natural fractures in the formation is an important consideration. Such fractures can quickly drain off fluid and bring the treatment to a premature end. Bridging agents, such as 70/170 mesh sand, are included to help prevent such rapid fluid loss.

The pumping volumes and rates are given in Table II for both foam and gelled water frac treatments. The calculated fracture designs are compared in Table III. The computer designs predict similar results for both the foam and gelled water for each location. However, the design only predicts the creation and proppant distribution in a fracture, and assumes the recovery of the frac fluid will be complete. To the extent the fluid is retained by the formation, damage by clay swelling, capillary imbibition, or some other mechanism can occur.

The length of time required to recover the frac liquid can be substantially different between foam and gelled water. A foam fractured well will typically be ready for testing and production in two days, but the gelled water fraced well may require longer times, with some swabbing to clean up.

PRODUCTION HISTORIES

The real value of a stimulation treatment does not lie in the designed fracture length or the calculated conductivity of a proppant bed but how the well responds in actual production. Several examples are available for wells in close proximity where some were fractured with gelled water and the others were fractured with foam.

In Mason and Jackson Counties, West Virginia, five wells, completed in the Devonian Shale, were selected as examples. The production of three wells fractured with foam were averaged and compared with the average production of two wells fractured with gelled water. The production decline curves are very similar, and are shown in Figure 1. The wells were shut-in the 12th month of production for approximately one month. The decline appears very constant once a steady state was reached. The average well production was slightly higher from the wells treated with foam fracturing than the average production from wells treated with aqueous fracturing fluids in this locale.

In Pike County, Kentucky, a group of four offset wells was completed in the Berea Sandstone. Two of the wells were fractured with foam, and two were fractured with gelled water. The average production of the two foam fractured wells, as shown in Figure 2, gave a steady decline curve for over two years. The wells fractured with water, on the other hand, produced in a less regular manner. The wells had to be shut-in on occasion to renew sufficient pressure for production. The rate of decline was greater than for the wells fractured with foam.

Another group of offset wells in Logan County, West Virginia, was completed in the Berea Formation. Logs from these four wells indicate similar porosity and pay zones for all the wells. Table IV lists the open flow test results for the two wells fractured with foam and the two wells fractured with gelled water. For this group of wells, the foam fractured wells cleaned up and tested substantially better than the gelled water fractured wells.

Two wells in Knott County, Kentucky, were completed in the Devonian Shale. One well had no initial gas indication. The well tested 103 mcf/d after foam fracturing, with a clean up time of 18 hours. First month production averaged 429 mcf/d. The other well gave a show of gas initially. After gelled water fracturing the well tested 143 mcf/d, with a clean up time of over two weeks. The first month production averaged 292 mcf/d.

A final group of 14 wells throughout Mason and Jackson Counties, West Virginia, were completed in the Brown Shale. Some of the wells, however, were near the edge of the depleted Cottageville field. All of the wells were treated with foam fracturing. They produced from one to 17 months with an average of 1337 mcf/month.

CONCLUSIONS

The foam fracturing technique has been shown to be a successful method for stimulating the Devonian Shales and Berea Sandstones of West Virginia and Eastern Kentucky. In the examples shown, foam fracturing led to production results equal to or better than production from wells fractured with gelled water. The clean up time of foam fractured wells was substantially shorter than clean up of gelled water fractured wells.

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Table I

Typical Formation Data for Fracturing in West Virginia Devonian Shale and Eastern Kentucky Berea.

	W. Va.	Ky.
Permeability, md	.01	.01
Porosity, %	10	10
Bottom Hole Treating Pressure, psi	1500	2500
Reservoir Fluid Pressure, psi	900	700
Closure Pressure, psi	1000	1100
Net Fracture Height, ft	150	30
Well Spacing, acres	100	40
Depth, feet	4000	3500
Bottom Hole Temperature, °F	85	85

Table II

Typical Fracturing Design for West Virginia Devonian Shale and Eastern Kentucky Berea

Foam Treatments	**W. Va.**	**Ky.**
Foam Quality	75	75
Foam Rate, BPM	40	25
Water Rate, BPM	10	6.25
Nitrogen Rate, SCF/min	17700	17800
Volume Injected Foam, bbl	1000	800
Sand, 70/170 mesh, lb	15000	15000
Sand, 20/40 mesh, lb	45000	30000

Gelled Water Treatments	**W. Va.**	**Ky.**
Water Rate, BPM	40	25
Polymer Gel, lb/Mgal	20	20
Volume Injected Water, bbl	1000	800
Sand, 70/170 mesh, lb	15000	15000
Sand, 20/40 mesh, lb	45000	30000

Table III

Fracture Characteristics Computed for Typical Designs of Table II.

	Foam		**Water**	
	W.Va.	**Ky.**	**W.Va.**	**Ky.**
Equivalent Bed				
Length, ft	288	560	484	938
Height, ft	250	50	219	27
Flow Capacity, md-ft	933	1342	954	1499
Bed Concentration, lb/1000 ft^2	417	804	282	903
Production Increase	3.1	7.1	4.1	6.6
Fluid Efficiency, %	88	88	89	87

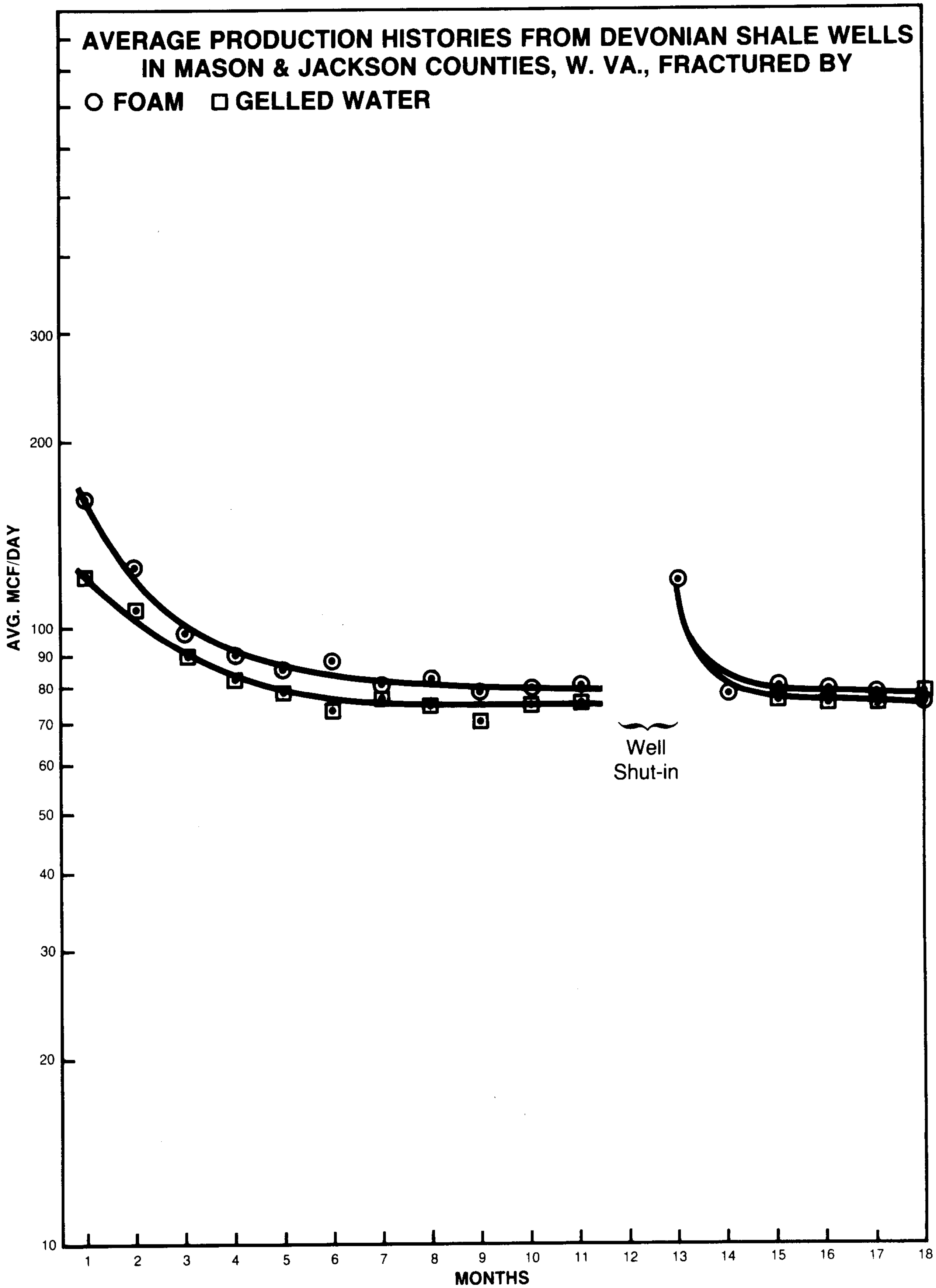
Table IV

Open Flow Tests in Logan Co., W. Va.,
in the Berea Sandstone

Treatment Type		Gas Rate		Clean-up
		Before Frac	After Frac	
Well 1	Foam	Show	599 mcfd	27 hr.
Well 2	Foam	Show	489 mcfd	21 hr.
Well 3	Gelled Water	Show	ITG*	60% in 24 hr.
Well 4	Gelled Water	Show	30 mcfd	72% in 36 hr.

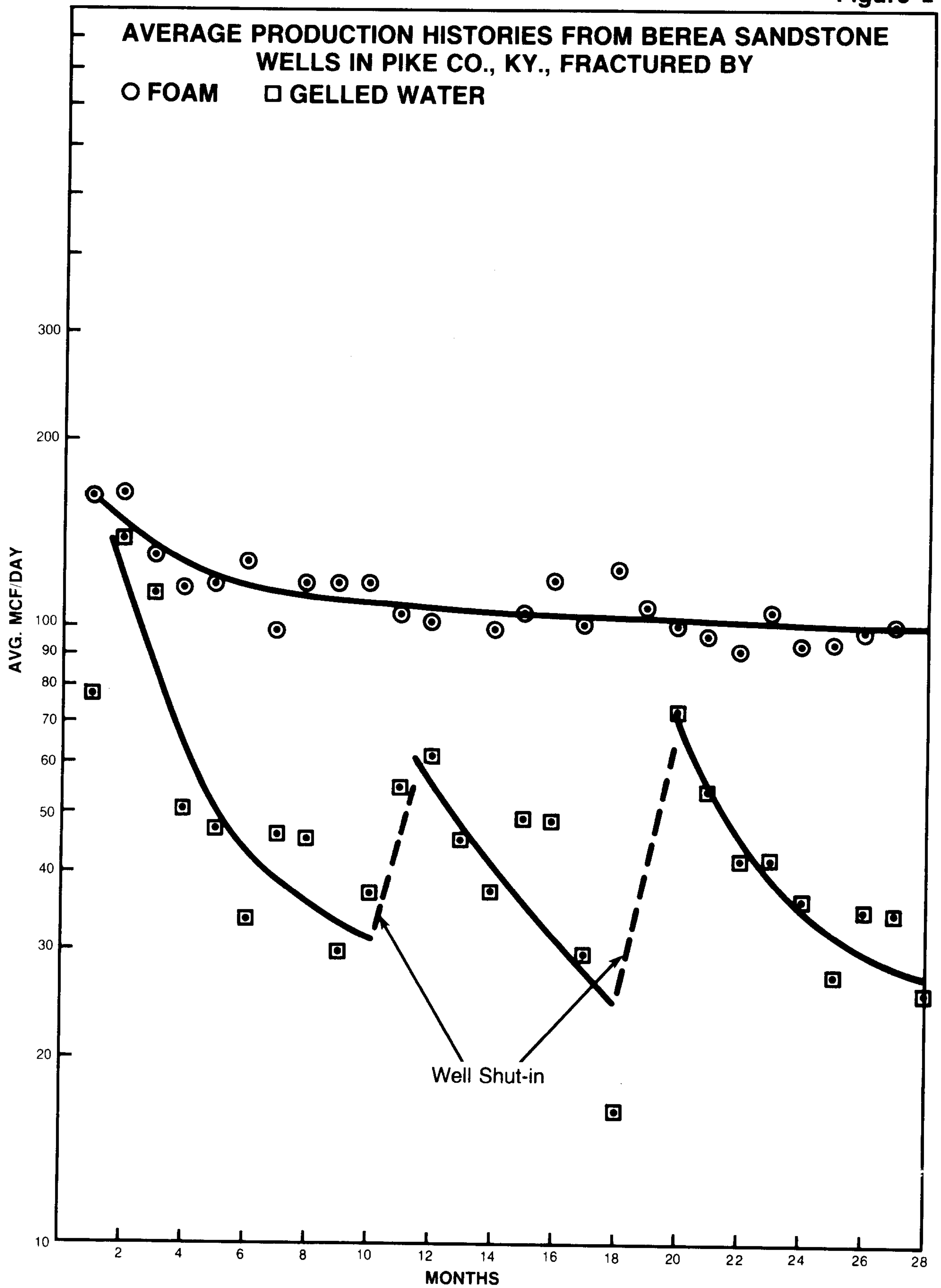
*Insufficient to gauge

Figure I



AVERAGE PRODUCTION HISTORIES FROM DEVONIAN SHALE WELLS IN MASON & JACKSON COUNTIES, W. VA., FRACTURED BY
○ FOAM □ GELLED WATER
AVG. MCF/DAY
300
200
100
90
80
70
60
50
40
30
20
10
Well Shut-in
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
MONTHS

Figure 2


AVERAGE PRODUCTION HISTORIES FROM BEREA SANDSTONE WELLS IN PIKE CO., KY., FRACTURED BY
O FOAM
□ GELLED WATER
AVG. MCF/DAY
300
200
100
90
80
70
60
50
40
30
20
10
2
4
6
8
10
12
14
16
18
20
22
24
26
28
MONTHS
Well Shut-in