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COMPARISON OF CONVENTIONAL HYDRAULIC AND WATER/NITROGEN FOAM FRACTURING IN TWO OHIO DEVONIAN SHALE GAS WELLS

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ABSTRACT

The current natural gas supply problems in the United States are encouraging research into new or underdeveloped gas sources. One such source is the Devonian Shale sequence of Kentucky, West Virginia, Pennsylvania, and Ohio. These thick shale deposits contain large gas resources, but have not been fully exploited because of the severely restricted gas well flow rates. Shale wells must be artificially stimulated to improve gas deliverability to a commercial level, and research is underway to develop a stimulation method suited to the Devonian Shale.

This report describes a performance comparison of two wells completed in the Shale near Youngstown, Ohio: one stimulated conventionally with hydraulic fracturing, the other with a nitrogen/water foam treatment. Both wells have comparable reservoir sections and received equivalently sized stimulation treatments.

Drilling and fracture programs for both wells are discussed along with short-term gas production tests conducted to evaluate the fracture treatments. Early indications show that the foam fracturing method is better suited to the reservoir conditions found in the Devonian Shale, resulting in much faster fracturing fluid clean-up and higher initial gas production than the conventional water method.

INTRODUCTION

The Morgantown Energy Research Center (MERC) of the U. S. Energy Research and Development Administration (ERDA) is conducting a research program on stimulating marginal natural gas wells through various fracturing techniques. The primary target of this stimulation research is the Devonian Shale sequence found under portions of Kentucky, West Virginia, and Ohio. This formation forms a series of very large natural gas reservoirs that have large gas resources in areas close to the Eastern domestic and industrial fuel markets, but most the areas have not been economically producible due to the severely limited permeability of the Shale.

One specific Shale area under investigation is situated on Youngstown Sheet and Tube Company (YST) acreage near Youngstown, Ohio. Here Lykes Resources, Inc., the resources operating company for YST, is currently drilling and completing a nine well program to tap the upper portion of the Devonian Shale sequence to provide fuel gas for YST steel making operations. These wells, six of which have been drilled to date, were made available to MERC to conduct hydraulic fracturing tests. The research program is designed to evaluate the relative performance of conventional water fracturing and the FOAM-FRAC* process developed by Minerals Management Inc. of Denver.

The preliminary report covers a summary of drilling and completion operations and subsequent gas production tests of two Shale Wells recently completed on YST acreage. One well was conventionally water fractured, and the other was stimulated with the foam process.

* Patent Applied for

ACKNOWLEDGEMENTS

The author wishes to acknowledge the cooperation of Lykes Resources, Inc. and its Director of Geology, G. H. Denton, in making their wells available for this research project. Especially appreciated is the help provided by Lykes Resources' C. F. DiMuzio, A. Lehrman, and W. Aston in gathering field data and conducting well tests.

WELL PROGRAM

Drilling

YST No. 16 and 17, the two wells covered in this report, were rotary drilled with fresh water and 6½-inch rock bits. Figure 1 shows the location of Devonian Shale wells as well as Clinton Sand wells penetrating the Devonian Shale on YST acreage.

YST No. 16 was drilled to a TD of 1060 feet in February 1975 and was logged with GR/neutron and density services. Figure 2 shows the GR/neutron logs over the gas-productive section of the Devonian Shale for YST Nos. 16 and 17. The productive interval is a sandy shale with higher porosity than the surrounding shales. This interval has been named "Silty" in the YST area. The well was cased with 10.5 lb., 4½-inch pipe set at 1032 feet and cemented to the surface.

The rig was then moved to YST No. 17 which was rotary-drilled to a coring point at 886 feet. At that point, ERDA in cooperation with Lykes Resources Inc., took an oriented core cut with a 6¼- x 3½-inch diamond core bit from 886 feet to 1001 feet, covering the "Silty" interval. At that point the well blew out with the core barrell still on bottom and fresh water in the hole. After rapidly unloading the hole, the gas flow quickly subsided to a very small flow. The well was loaded again with fresh water and was drilled to TD at 1051 feet without further incident.

A suite of logs including gamma ray/neutron-density, induction, and caliper logs was run in the well. A 3-D velocity log was also attempted, but failed due to noise from the continuing low-rate gas flow into the water-filled wellbore at about 1050 feet. Casing was then run to 1051 feet and cemented back to the surface.

Core Analysis

A total of 115 feet of 3½-inch diameter core was recovered from YST No. 17. Table 1 gives the core analysis of selected portions of the core. The samples were selected to cover the more sandy, higher porosity sections of the core. Measurements of porosity and maximum and 90° permeabilities were whole-core derived.

Directional mechanical property analyses of other portions of the core were conducted to determine the frequency of naturally occurring microfractures and to predict the preferred direction of induced hydraulic fracture orientation. These tests included (1) microfracture analyses, (b) directional tensile strength, (c) directional sonic pulse transit time, and (d) identification of preferred planes of weakness in the formation.

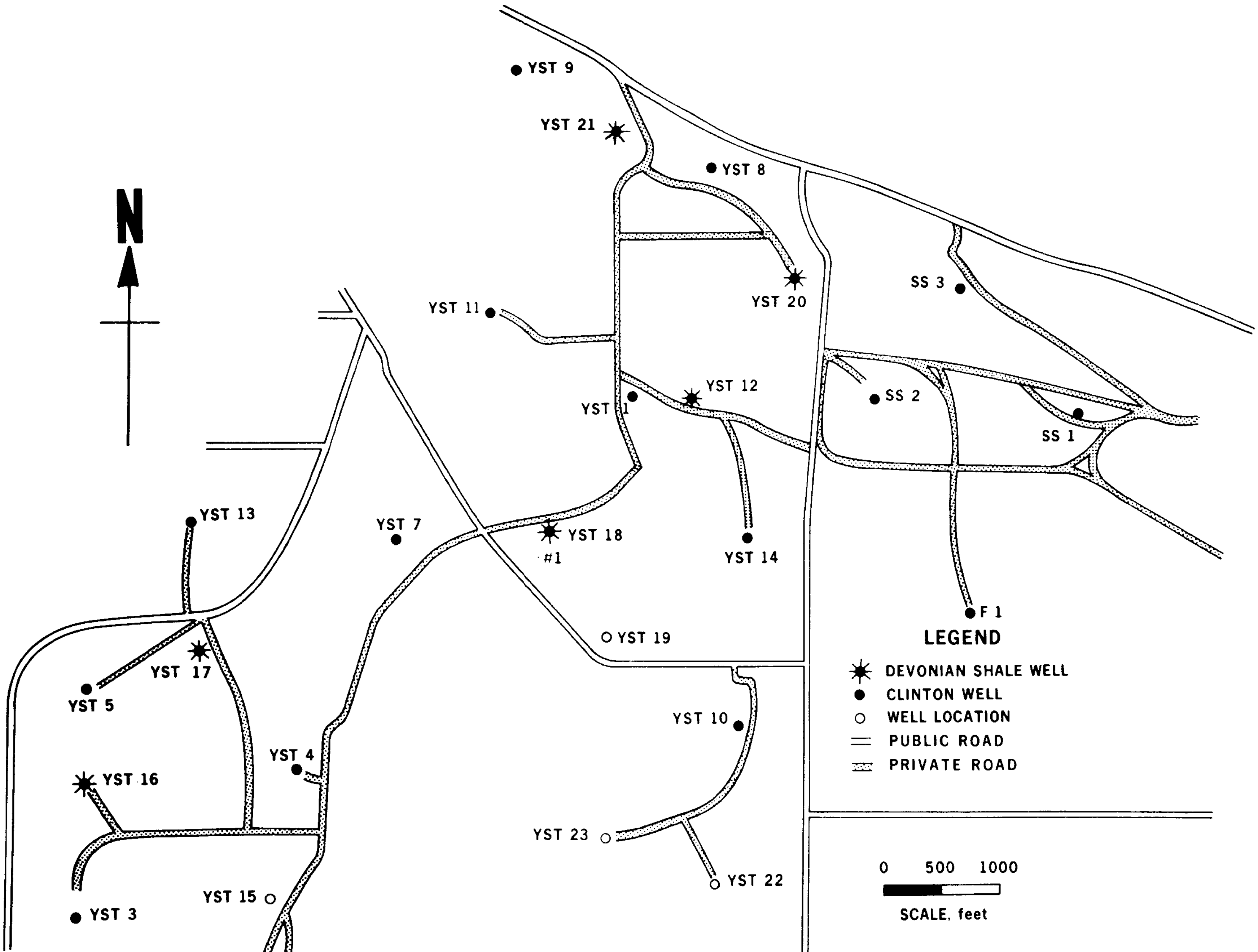

FIGURE 1. – Well Map – YST Acreage, Youngstown, Ohio.

Sample No.	Depth	Max. Perm.	90 Perm.	Porosity	Grain Density
1	905.28-05.92	4.2	1.9	4.0	2.71
2	23.00-23.50	17.0	3.0	4.9	2.73
3	31.68-32.12	1.1	<0.1	7.0	2.70
4	34.29-35.04	<0.1	<0.1	7.2	2.68
5	47.93-48.54	1.2	0.3	4.4	2.68
6	51.35-52.06	<0.1	<0.1	6.1	2.68
7	80.33-80.85	1.5	<0.1	7.1	2.68
8	83.07-83.49	0.3	0.1	6.9	2.69
9	84.34-85.02	1.5*		6.0	2.69
10	93.67-94.24	<0.1	<0.1	8.7	2.71
11	94.50-95.04	16.0	0.5	5.1	2.72
12	997.89-98.50	0.7*		9.0	2.70

* Denotes plug permeability

TABLE 1. – Core Analysis – YST No. 17.

Identification of microfractures and planes of weakness that could be opened during the fracturing process indicated the azimuth direction of N-N15E (Figure 3) as the major weakness trend. These microfractures could act as stress risers during the extension of an induced hydraulic fracture and hence control the direction of fracture orientation. However, the microfracture system in the YST No. 17 core was not very pronounced, and no evidence of macroscopic fracturing was found in the core at time of coring.

Directional tensile strength and sonic velocity tests identify the azimuth of N-S (Figure 3) as the direction of minimum strength and minimum sonic velocity. This "minimum" direction is usually normal to the principal direction of fracture orientation. Considering that these latter tests are directly related to the deformation of the rock formation as a result of in-situ stress, these tests can be considered prime predictors of the preferred direction of induced fracturing. Accordingly, the preferred orientation of induced hydraulic fractures in this region is E-W. Independent studies by the U. S. Bureau of Mines in a limestone mine near Barberton, Ohio (directly west of Youngstown) support this observation of E-W fracture orientation.

Completion-Foam Fracturing

YST No. 17 was selected for the foam-fracturing process[1], and Minerals Management, Inc. (MMI) acted as a consultant to ERDA on this well. MMI designed the foam treatment based on core-derived rock properties, on formation water chemistry, and on geophysical logs of the "Silty" interval. The foam-fracturing design is summarized in Table 2.

YST No. 17 was fractured June 24, 1975. The operation went smoothly, and 68,500 gallons of foam carrying 52,500 pounds of sand proppant were pumped into the formation. The foam was initially injected at a surface pumping pressure of 1700 psig, which gradually decreased to 1300 psig. The instantaneous shut in pressure at the completion of the job was 1000 psig.

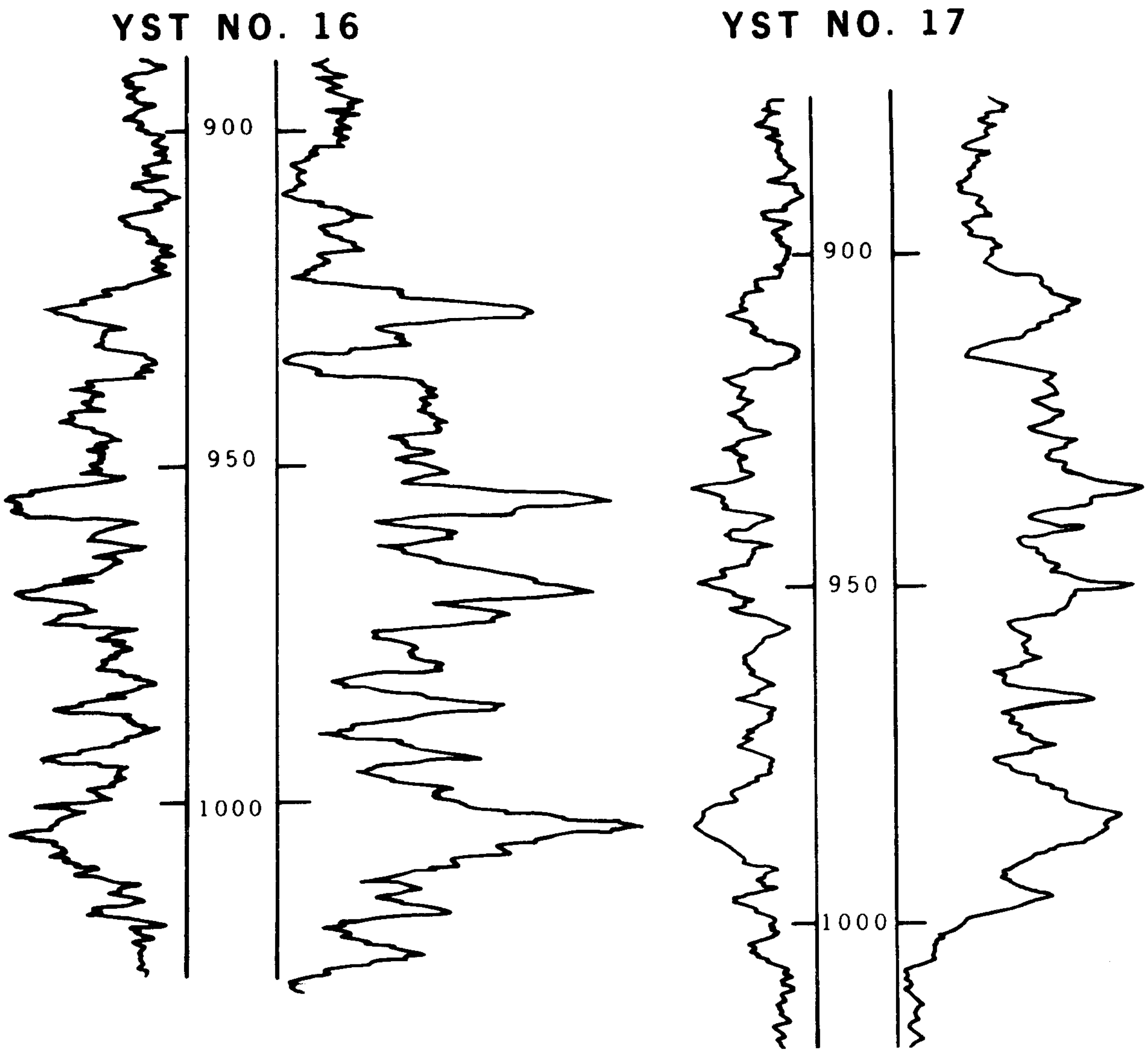

FIGURE 2. – Gamma Ray – Neutron Logs – YST Nos. 16 and 17.

Flow-back of frac water and nitrogen began about 1½ hours later. This is a critical period in which the foam is designed to break down in the fracture into nitrogen and water, and the rate of flow must be closely controlled to prevent sand proppant from being brought back to the surface. Flow rates were controlled with positive bean chokes, and Table 3 summarizes the flow back schedule of YST No. 17.

During a 40 hour flow-back period the well produced 121 barrels of water into a 300 BBL frac tank to measure water recovery with perhaps another 4 or 5 barrels lost on the ground during sand-check periods. This is about 35% of the 350 barrels of water injected.

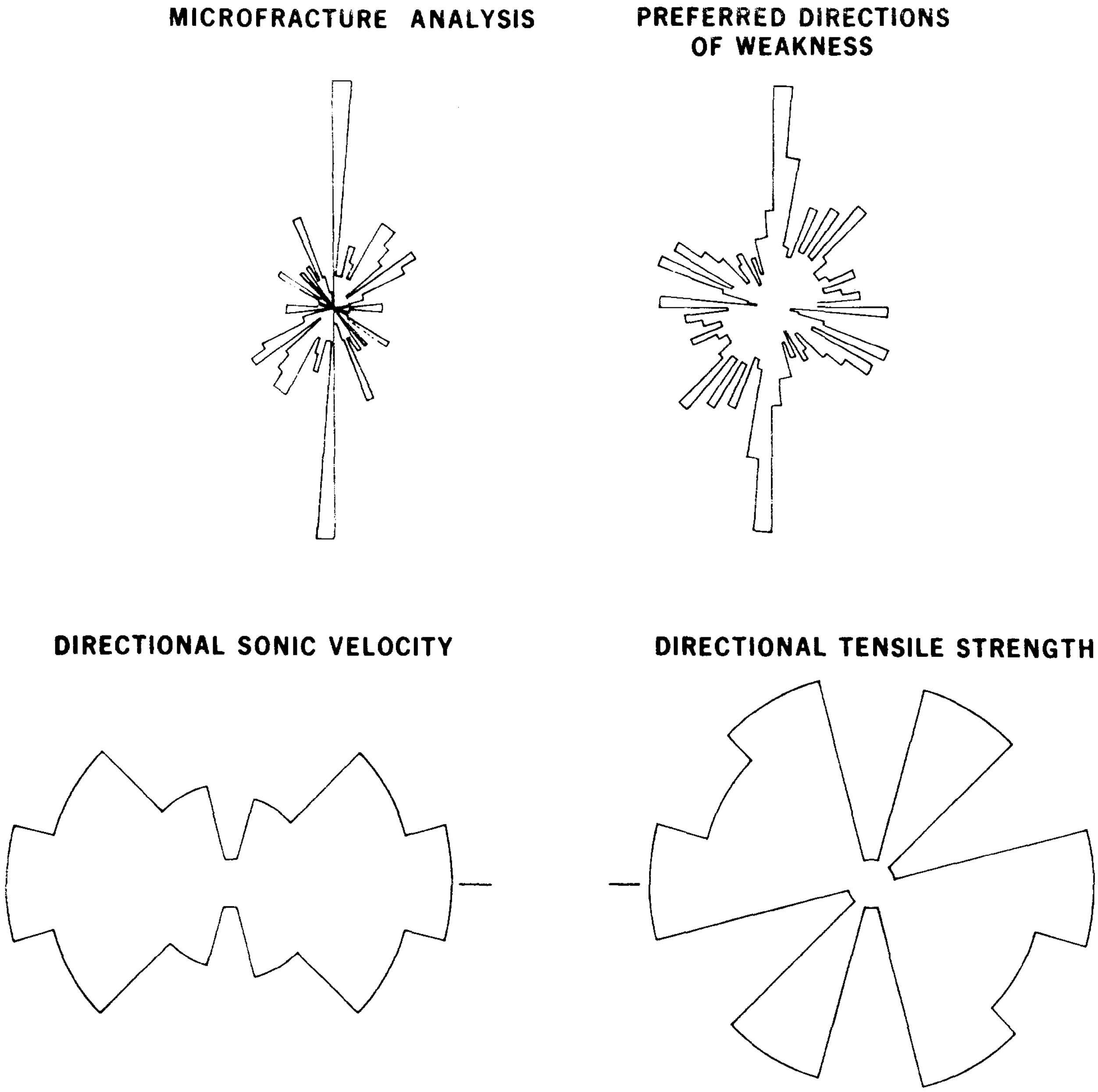

FIGURE 3. – Directional Properties – YST No. 17.

The cleanup period was longer than expected and sand return was higher than expected due to too much foam stability. However, although sand was produced almost continually during the flow-back, less than 500 pounds of the 52,500 pounds injected was actually brought back. Job cost for foam fracturing YST No. 17, including design, supervision, service rig, chemicals, nitrogen, sand and pumping expenses, was $12,600.

Gross formation interval (depth)	902–998 ft.
Number of 0.38 inch diameter perforations	7
Assumed bottom hole treating pressure	1000 psia
Surface treating pressure	1111 psia
Friction drop across perforations	191 psia
Treatment water volume	12,800 gal.
Treatment nitrogen volume	500,000 SCF
Sand proppant amount (20/40 mesh)	46,000 lb.
Down-hole foam volume (80 quality)	64,000 gal.
Water injection rate	4 BPM
Nitrogen injection rate	5,800 SCFM
Down-hole foam injection rate	20 BPM
Water additive concentration KCL	2%
Water additive concentration – $CACl_2$	0.5%
Water additive concentration – Surfacant	3 gal./1000 gal. water
Water additive concentration – Non-emulsifier	0.5 gal./1000 gal. water

TABLE 2. – FOAM-FRAC Treatment Design Summary – YST No. 17.

Completion-Water Fracturing

YST No. 16 was fractured on April 18, 1975 in the conventional manner with water and sand. The casing had been perforated with 17 capsule jets spaced over the "Silty" interval from 927 feet to 1008 feet, and the formation was broken down with 500 gallons water and 2450 psig surface pressure. Following breakdown, a mixture of 100 gallons of a clay control hydroxyl compound in 6000 gallons water was pumped into the formation to inhibit swelling of clays. This was followed by 500 gallons of fresh water and then a pad of 40,000 SCF of nitrogen to aid in well clean-up. The clay control agent, the fresh water, and the nitrogen pad were all pumped at 3200 psig surface pressure.

The main treatment consisted of 58,000 gallons of water containing gelling agent, gel breaker, a friction reducer, and carrying 50,000 pounds of 10/20 mesh sand. Treating surface pressures varied from an initial 4000 psig to a final 1200 psig, averaging 3050 psig. Simultaneously with the water/sand mixture, nitrogen was injected into the fracturing water stream at a rate of 170 SCF/BBL water for a total of 190,400 SCF. This nitrogen was designed to improve frac water recovery from the well. The fracturing treatment was then completed with a 1000 gallon water flush to displace the remaining sand and fluid from the wellbore into the fracture.

After a shut-in period of about an hour the well was permitted to flow back to recover the fracturing fluid. The well was flowed without restriction and produced an estimated 33,000 gallons of water (about 50%), leaving the remaining 50 per cent (785 barrels) in the fracture system. Job costs including consulting fees, design, chemicals, sand, nitrogen, pumping, and service rig expenses totaled $16,475.

Cumulative Time	Wellhead Pressure	Choke Size	Comments
0 hours	950 psig.	10/64 in.	Start flow-back procedure.
0.33	900 psig.	10/64 in.	Nitrogen and milky mist.
0.66	890 psig.	10/64 in.	Shut in, change to 15/64 choke.
0.75	890 psig.	15/64 in.	Sand, change to 10/64 choke.
1.0	895 psig.	10/64 in.	N_2 and mist, moderate sand.
4.0	830 psig.	10/64 in.	Choke cutting by sand..
4.66	810 psig.	10/64 in.	Choke continuing to cut out.
7.0	775 psig.	10/64 in.	N_2, mist, moderate sand, choke still cutting out.
8.62	475 psig.	10/64 in.	Choke washed out, lot of sand, changed choke.
10.0	710 psig.	15/64 in.	N_2, milky mist, moderate sand.
12.75	600 psig.	15/64 in.	Same as above, checked choke.
19.0	480 psig.	15/64 in.	Same as above.
24.50	360 psig.	15/64 in.	Same as above, changed choke.
24.75	200 psig.	20/64 in.	Well beginning to slug water.
28.83	110 psig.	20/64 in.	Well unloading in slugs, increased choke.
29.0	60 psig.	32/64 in.	Well slugging.
31.0	50 psig.	32/64 in.	Water flowing by heads, low amount of sand.
31.50	30 psig.	32/64 in.	Well cycling water and gas.
32.0	60 psig.	32/64 in	Same as above.
34.50	100 psig.	64/64 in.	Well flowing water, gas.
39.67	0 psig.	64/64 in.	Natural gas and N_2, no water.

TABLE 3. – **Flow-Back Period Summary – YST No. 17.**

Well Performance Testing

YST No. 17 was performance tested beginning June 30. At that time the well was opened for 3 hours to reduce the nitrogen concentration in the reservoir. During the flow period, well surface pressure was dropped from an initial 450 psig to a final 40 psig. An Amerada type RPG bottom-hole pressure bomb rated for 1500 psi, and with a 72 hour clock was run into the well and positioned in the center of the producing zone. The well was then shut in to measure the pressure build up.

On the morning of July 2, a modified isochronal flow-test was run on the well. Table 4 summarizes the flow-test data. Flow rates were measured with a 2 inch diameter orifice meter run and 0.750 inch orifice plate. Flow-rates were controlled by varying orifice meter pressure differential.

Figure 4 shows the isochronal performance curve[2] for YST No. 17. At the conclusion of the short-term flow tests the BHP instrument was pulled from the well and then rerun with a 7 day clock. The well was shut in for a pressure build-up curve.

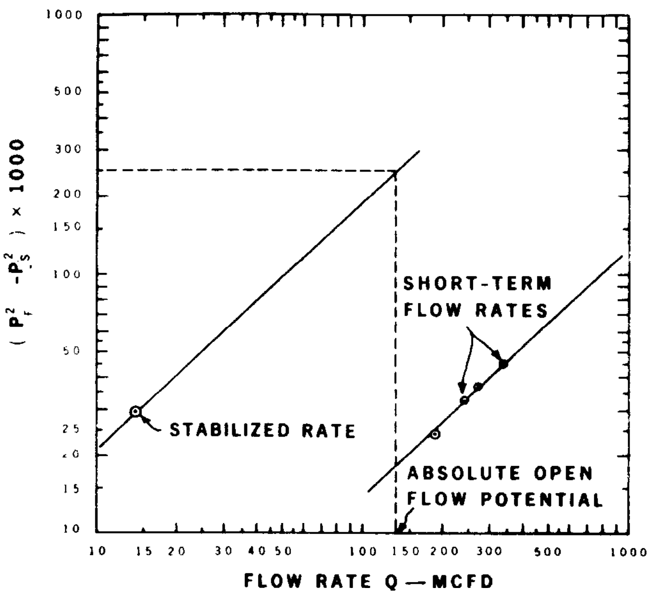

FIGURE 4. – Isochronal Performance Curve – YST No. 17.

On July 10 the well's surface pressure was 449.3 psia and the well was opened up through a 0.250 inch orifice plate to obtain a stabilized flow rate. The well's surface pressure decreased to 438.2 psia (measured with a dead-weight tester), where flow stabilized at a rate of 13,961 SCFD. The corresponding stabilized bottom-hole pressure was 450.0 psia flowing.

Based on Figure 4, the absolute open flow potential of YST No. 17 is 133,000 SCFD with a drawdown of 50 psi from the estimated static bottom-hole pressure of 500 psia.

The pressure build-up test conducted for 161 hours on YST No. 17 proved inconclusive due to insufficient shut-in time. Because of the very low permeability of the reservoir matrix the pressure build-up rate did not stabilize, and the reservoir flow capacity could not be determined. The static reservoir pressure was estimated to be 500 psia based on extrapolation of the 161 hour build-up.

YST No. 16 was tested beginning July 14, 1975. The well had been produced intermittently, since being hydraulically fractured on April 18, in order to reduce the remaining frac water concentration. Gas production was severely limited due to water in the well bore.

On July 14, a BHP instrument was run into the well to record reservoir pressures during the test, and the bottom-hole pressure was 380 psia compared to a surface pressure of 366 psia. Since the gas column weighed about 8 pounds, this indicated that the perforations were partially covered by water in the well bore.

On July 15, an attempt was made to run a modified isochronal flow test. The well was alternately flowed and shut in for 1 hour periods, but after 3 flow periods the test was stopped because of insufficient pressure drawdown.

The test was repeated on July 16 using a larger orifice plate to increase flow rates and pressure drawdowns. After obtaining 3 flow rates to determine the slope of the isochronal performance curve shown in Figure 5, an attempt was made to stabilize the flow rate to complete the performance test. This attempt was unsuccessful when the flow rate and well pressure could not be stabilized because of continued frac water entry into the well bore. Table 5 is a listing of flow test data available.

At the conclusion of the flow tests the well was open-flowed for a few hours to draw down the well pressure and to unload some of the water. The well was then shut in and a 7-day pressure bomb was run in. The bottom-hole instrument was rerun 2 more times recording pressure versus time for 21 days; at the same time a surface recording gauge measured the well pressure. Using the 21 day period to correlate between surface and bottom-hole pressures, the bottom-hole pressure was estimated from continued surface recordings for an additional 17 days, in effect giving a 38-day build-up period. Again this 5½ week build-up was not sufficiently long to reach a stabilized pressure buildup rate, and it was not possible to do a build-up analysis.

Test No.	Initial Static Pressure P_F, psia*	Final Flowing Pressure P_S, psia*	Difference of Squares $(P_F^2 - P_S^2)$	Flow Rate Q, MCFD
1	415.5	385.3	24184	183.7
2	409.4	367.4	32626	238.4
3	405.4	356.3	36686	269.8
4	370.4	303.2	44957	336.0
Stabilized	500.0	470.0	29100	14.0

* All static and flowing pressures measured bottom-hole.

TABLE 4. – Modified Isochronal Flow Test – YST No. 17.

CONCLUSIONS

The short-term well testing program conducted on YST No. 16 and No. 17 to evaluate the relative merits of foam versus water fracturing techniques in the Devonian Shale of eastern Ohio proved to be unsuccessful from the quantitative viewpoint. This was primarily due to insufficient clean-up time of the water-fractured YST No. 16, and the very low reservoir permeability of both wells which showed that 4½ weeks was not long enough to reach a stabilized build-up rate.

From a practical or qualitative standpoint, however, it is obvious that the foam technique is more effective in the Devonian Shale, "Silty" zone near Youngstown. The most obvious benefit is the rapid water clean-up time of the foam-fractured YST No. 17. This well was essentially cleaned up of mobile frac water in 2 days after frac, and was then ready for gas production. YST No. 16, by comparison, had about 785 barrels of water left in the reservoir. Most of this water is mobile and is pulled toward the wellbore whenever the well is produced for more than a short time. The water then is drawn into the well, restricting the flow of gas. Where YST No. 17 has had no noticeable water production since being connected to the pipeline, YST No. 16 is still producing water whenever the well is placed on production, rapidly drawing the well producing pressure down to the point where the well logs up with water.

These short-term well evaluation tests have shown that more time is needed to evaluate quantitatively the relative merits of foam and water fracturing methods in the Devonian Shale. The wells, both foam and water, should be fully cleaned up of mobile frac water before being flow-tested to evaluate the production capacities of the wells. It has also become apparent that longer shut-in times are necessary to permit the wells to reach stabilized pressure build-up rates.

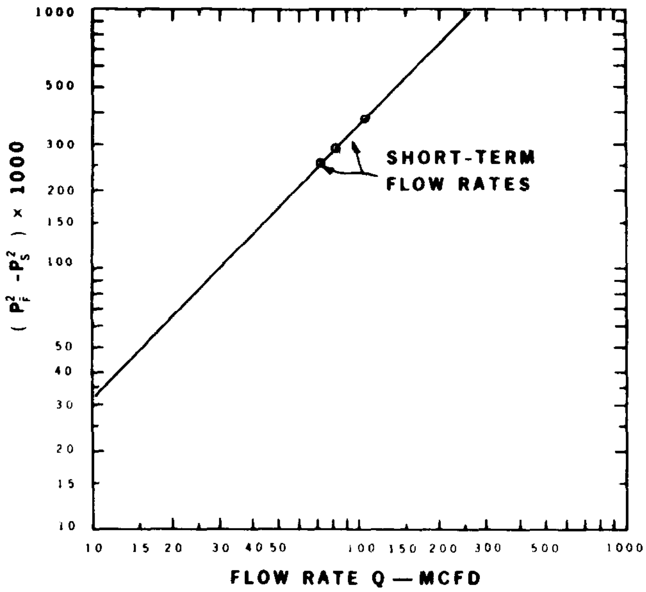

FIGURE 5. - Isochronal Performance Curve - YST No. 16.

Lykes Resources, Inc. has recently completed 3 more shale wells with the foam fracturing method, and more well performance tests are planned. YST No. 16 is still being cleaned up and will be re-tested when conditions are suitable.

Test No.	Initial Static Pressure P_F, psia*	Final Flowing Pressure P_S, psia	Difference of Squares $(P_F^2 - P_S^2)$	Flow Rate Q, MCFD
1	307	262	25605	72580
2	272	212	29040	83273
3	240	140	38000	100590

* All test pressures measured bottom-hole.

TABLE 5. - Modified Isochronal Flow Test - YST No. 16.

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