EXHIBIT 28

SPE

Society of Petroleum Engineers

SPE 17759

Hydraulic Fracturing of a Horizontal Well in a Naturally Fractured Reservoir: Gas Study for Multiple Fracture Design

by A.B. Yost II, U.S. DOE METC; W.K. Overbey Jr., BDM Corp.; D.A. Wilkins, Grace, Shursen, Moore & Assocs.; and C.D. Locke, BDM Corp.

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This paper was prepared for presentation at the SPE Gas Technology Symposium, held in Dallas, TX, June 13–15, 1988.

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ABSTRACT

Stimulation of a naturally-fractured, low permeability, low-pressure 2000-foot horizontal well in a low permeability reservoir and in-situ stress environment requires careful stimulation fluid design to minimize the capillary retention of treatment fluids. Therefore, a systematic approach to stimulation design using N_2, CO_2, and N_2-foam was used to select one which is most efficient. Stimulation modeling was used to evaluate fracture geometry with particular concern for the minimum pressure rise above parting pressure required for height growth during frac fluid injection. Up to seven zones along the horizontal wellbore are available for stimulation. Each zone was ranked and pre-frac tested to establish pre-frac permeabilities. A N_2 and N_2-foam data frac was performed in one zone to establish leakoff characteristics. Subsequently, N_2, CO_2, and N_2-foam treatments were performed on a 400-foot zone to evaluate the effectiveness of CO_2 versus N_2 frac fluids. Both the data frac and subsequent stimulations were evaluated in the two least productive intervals in order to use the preferred fluids in the best zones in the reservoir. The post-treatment decline curves for N_2 and CO_2 indicate a CO_2-based fluid treatment should be performed in the most productive interval to achieve maximum success. Results of the stimulation conducted are presented along with discussion of improvement ratios and potential utility to other horizontal drilling projects.

BACKGROUND

The stimulation aspects of horizontal drilling represent a technical challenge in tight formations where the horizontal placement of a horizontal wellbore may not always provide adequate economic production. Little or no published literature exists on the mechanics of hydraulic fracturing of horizontal wells. Typically, long horizontal wells are completed with preperforated liners to preserve hole integrity. The disadvantage of this type of completion is the associated risk of pulling the liner at a later stage of production history and re-running and cementing a casing string such that selective placement of fracturing of fluids can be accomplished. An alternative approach is zone isolation accomplished by the installation of external casing packers and port collars as an integral part of a casing string run along the horizontal section. Such a completion arrangement provided stimulation intervals with ready-made perforations injecting fracturing fluids into an open hole fracturing condition behind pipe. This was the method of completion used in this 2000 foot horizontal well to avoid the problems of formation damage associated with cementing and to eliminate the need for tubing-conveyed perforating of numerous treatment intervals.

The U.S. Department of Energy's Morgantown Energy Technology Center has been investigating the merits of drilling high angle wells for more than 20 years. Two high angle wells were completed in the Devonian Shale at 43 and 52° from vertical. Recent emphasis has been on the use of horizontal wellbores to enhance gas recovery efficiency in tight formations.[1] Initial study of horizontal drilling in fractured Devonian Shale in the Appalachian Basin involved selection of a geographic area followed by full-field reservoir simulation and initial well design.[2] Once the site was selected, computer software was used to examine drill string loads, design bottomhole assemblies, track well trajectory, and to provide daily reporting during drilling.[3] Finally, the 2000 foot long horizontal well discussed in this paper was air-drilled to a measured depth of 6020 feet and a true vertical depth of 3403 feet.[4] A video

References and illustrations at end of paper.

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camera survey and analysis was used along with geophysical well logs to determine fracture spacing and to locate the position of external casing packers for completion and stimulation operations.[5] A follow-on study using reservoir data from the drilling, coring, logging and well testing operations was used to examine the effects of in-field drilling with horizontal wells as a field development strategy in fractured Devonian Shale.[6]

INTRODUCTION

The objective of stimulation research in this horizontal wellbore, located in Wayne County, West Virginia, was to determine the recovery efficiency of the natural fracture system and the effects expected from hydraulically fracturing the well whenever multiple fractures would be induced. To determine the most effective wellbore stimulation under these conditions, it was necessary to use a systematic approach to examine the effects of various combinations of four factors, which were: (1) type of fluid (e.g., gas, liquid, foam); (2) fluid injection rate; (3) volume of fluid injected; and (4) bottomhole treating pressure. Following each stimulation, flow rate and build-up test data were used to determine permeability-thickness product and flow rate improvement ratio. Key stimulation issues of concern were:

- number of fractures that can be opened and propagated during a single pumping event;
- whether proppant would screen out easier in a horizontal well;
- understanding what determines which natural fractures are propagated;
- determining the best fracture diagnostic system to use in a horizontal well.

The overall technical approach was to:

- induce multiple hydraulic fractures;
- determine how many and where fractures were induced in the borehole;
- evaluate hydraulic fracture design for horizontal well in shale formation;
- establish need or lack of need for proppant in low stress ratio (minimum horizontal to vertical) areas.

Conceptual hydraulic fracture design had to consider the strong interaction between the natural fracture orientation of N37°E and N67°E and the predicted induced fracture trend of N52°E as shown in Figure 1. In addition, the consideration of other joint system having nearly parallel orientations which would either act as leakoff areas or actually accept fracture fluid under propagating conditions. Each zone available for fracturing had numerous natural fractures which would accept fracturing fluid. Therefore, the need for acquiring injectivity information was warranted to observe whether multiple hydraulic fractures were propagated during a single pumping event as postulated in Figure 2.

Pre-Stimulation Input Data

In order to fully evaluate the effects of propagating natural fractures, detailed evalution of mud log shows and natural fractures observed from a drill-pipe conveyed video camera were made. In addition, eight zones were originally isolated with external casing packers (ECPs) and port collars as shown in Figure 3. Following inflation of ECPs, only seven zones were available for pre-frac well testing due to one ECP failure between Zones 2 and 3. A combination tool was used to open and close port collars as well as provide pack-off for zone isolation during pre-frac testing. Pre-frac flow rates from individual zones varied from 2 to 17 thousand cubic feet of gas per day (mcfd). In addition, pressure build-up tests were conducted on all seven zones with permeabilities ranging from .031 to .098 millidarcies (md). The initial design considerations were premised on the fact that mud log shows would be the best indication of where frac fluid would first be accepted during stimulation. A summary of all pre-stimulation input data and reservoir characteristics is provided in Table 1 and Table 2 respectively.

Stimulation Rationale

The mechanical handling of fracturing fluids, proppants, and tracer materials along a 2000 foot horizontal wellbore offers a technical challenge relative to developing a systematic approach to conducting fracturing experiments in selected zones without causing any permanent damage to the wellbore that would prevent execution of remaining stimulations. The rationale used was to select the lowest productive zone(s) to conduct experiments in and subsequently, reserve the better zones for full-scale stimulation. In Figure 3, both Zone 6 and 1 were used for all frac fluid testing which will be the focus of this paper. The overall stimulation rationale focused on the following considerations:

1) Primary design was to propagate natural fractures with a slight difference in orientation from principal stress orientation.
2) Injection at low rates allows fluid to select pre-existing natural fractures to be propagated.
3) Injection at pressures which will keep the fracture(s) from growing out of zone.
4) By starting off at low rates and not exceeding 200 psi above closure pressure with average BHTP natural fractures would be propagated.
5) By increasing injection rates additional fractures would be induced which would likely create a network of interconnected fractures with orientations of N37°E, N52°E, and N67°E.

The initial frac design sequence was premised on treatment of Zone #6 with both N_2 and foam injection tests to verify fluid leakoff characteristics for low and high viscosity fluids. The initial flow diagram was developed to conduct pre-frac tests on Zone #6 followed by hydraulic fracturing experiments using straight N_2 and CO_2 on Zone #1 followed by N_2-foam without proppant on Zone #2-3 and #5 as shown in Figure 4.

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DATA FRAC DESIGN, EXECUTION AND EVALUATION

As previously discussed, Zone #6 was selected for data frac experiments to determine leakoff characteristics. A computer-controlled data acquisition system was used to perform fluid injection tests. The data frac treatment procedure is described as follows:

1. Pump straight N_2 down hole to load hole at 5 bbl/min (2500 scfm) to fill wellbore. (Wellbore storage calculated at 51,000 at 1600 psi.) Estimated time: 20.4 minutes.

2. Pump Test #1 at 5 bbl/min rate for 15 minutes. (2500 scf x 15 minutes = 37,500 scf N_2)

3. Shut in for 37.5 minutes and watch leakoff.

4. Pump Test #2 at 15 bbl/min rate for 15 minutes. (7500 scf N_2 x 15 minutes = 112,500 scf N_2)

5. Shut in for 37.5 minutes and watch leakoff.

6. Pump 80 quality foam at 5 bbl/min for 20 minutes (tag with radioactive iodine). (40,000 scf N_2)

7. Shut in for 50 minutes to watch leakoff. Note ISIP calculated closure pressure.

8. Pump 80 quality foam at 15 bbl/min for 20 minutes. (Tag with second RA liquid.) (120,000 scf N_2)

9. Shut in for 50 minutes to watch leakoff. Note ISIP and calculated closure pressure.

10. Within 2.5 hours, replumb well for flow back.

Approximately 25,000 scf of N_2 was used to load the hole to start the data frac activities in Zone #6.

Pump test #1 was pumped for 15 minutes at an average rate of 2500 scfm of N_2, then shut-in for 15 minutes to watch leakoff rate. Leakoff rate was 6.6 psi per minute. A total of 37,500 scf N_2 was pumped into the formation.

Pump test #2 was pumped for 15 minutes at a programmed rate of 7500 scfm of N_2, however, the rate meter was in error and injection rate is projected to be 10,000 scfm since the unit was running wide open. A total of 150,000 scf of N_2 was pumped into the formation. Leakoff rate was 8.4 psi per minute.

Pump test #3 was pumped for 20 minutes at 5 bbl/min of 80 quality foam. Leakoff rate was 4.15 psi per minute after Test #3; 33,000 scf of N_2 was pumped during this stage. Radioactive scandium was injected as a tracer for this test. A total of 100 bbls (4200 gallons) of foam was injected in the formation.

Test #4 was pumped for 16 minutes at 12 bbl/min of 80 quality foam. Leakoff rate was 4.7 psi per minute for the final stage; 69,200 scf of N_2 was pumped during this stage. Radioactive iodine was injected with the foam as a tracer for the final test. A total of 200 bbls of foam (8400 gallons) was injected in the formation. A pressure versus time plot is provided in Figure 5.

Results from the data fracs as shown in Table 3 indicate the following: (1) two different closure pressures (850 and 1050 psi) were observed from the N_2 and N_2foam injection test. One possible explanation was that different fractures were induced having near-adjacent angles in Zone #6; (2) calculated fluid loss coefficients varied from 2.75 x 10^{-4} to 1.38 x 10^{-3} ft/$\sqrt{\text{min}}$ between N_2-foam; (3) frac gradients ranged from .25 to .31 psi/ft; low frac gradients provide a formation stress environment where proppants may not be necessary; (4) fracture diagnostics indicate that the differences in foam injection was not enough to alter the preferential fluid acceptance paths established by an initial injection rate of 5 barrels per minute, and (5) fracture diagnostics showed four of six natural fractures were opened and propagated, plus 9 additional fractures were generated which interconnected with Zone #5.

Following the four data frac experiments on Zone #6, a spectral gamma ray, casing collar, and temperature log was run into the well on coiled tubing through Zone #6. Evaluation of the tracer log indicates that the majority of the tracer material was located in the vicinity of the only mud log gas show in Zone #6. However, up to 13 fluid entry points were observed in Zone #6 on the tracer log as compared to 6 natural fractures observed on the downhole camera.

Following well logging, Zone #6 was produced and cleaned up over a 7-day flow period and a 75 psi back pressure was applied to simulate flowing conditions. After 10 days of flowing, Zone #6 was flowing 14 thousand cubic feet of gas per day (mcfd) as compared to a pre-frac rate of 2 mcfd. After 3 days of simulated back pressure, the well's flow rate suddenly dropped to 9 mcfd as shown in Figure 6. A plausible explanation for this drop in rate was some of the induced fractures were closing off. Subsequently, 4 days later Zone #6 was opened to atmospheric conditions and production rate dropped to 3 mcfd; however, when the 75 psi back pressure was reestablished, Zone #6 began producing 9 mcfd, a 4.5-fold increase over baseline conditions. A plausible explanation for this type of flow behavior is that the natural gas liquids, observed in the fracture by the downhole video camera, restrict the gas flow under open flow conditions. Subsequently, the addition of back pressure improves the relative flow potential.

After flow rate testing, a 14-day build-up test was performed on Zone #6. Both the pre-frac and post-treatment build-up test for Zone #6 are shown in Figure 7. Results of the build-up test analysis indicate a permeability increase from .079 to .184 md, while the measured flow improvement ratio was 4.8 to 1.

After the data frac execution and evaluation, a logic diagram was developed for the remaining stimulations as shown in Figure 8. An overall improvement ratio of 9:1 was used as a goal of stimulation. If this improvement ratio was achieved, then all remaining stimulations would be performed in a similar manner and the tests were complete.

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STIMULATION TREATMENTS

Nitrogen Stimulation

The RET #1 well was stimulated with 1,165,000 scf of nitrogen in Zone #1. The test was designed as a low rate, high volume test. Based on hydraulic fracture modeling of fracture propagation of nitrogen into a single fracture, the bottomhole treating pressure required above minimum stress (differential pressure) was calculated in the range of 150-200 psi to maintain hydraulic fracture containment within the 250 foot shale section. An on-site computer control vehicle was used to attempt to maintain a constant incremental pressure of 200 psi above closure pressure during stimulation. Injection started at 2000 cfm and only could be increased to 5000 cfm during the job because of erroneous N_2 fluid rheology currently being used to calculate differential pressure plots during stimulation. In fact, a quartz-crystal pressure guage located downhole confirmed that the friction pressure error was more than the designed 200 psi (differential pressure) required for the fracture containment experiment. The frac job could have been pumped at much higher rates because the actual differential pressure during pumping was less than 100 psi. However, the job was completed without interruption. The well was then opened up completely and blown down to remove the quartz pressure gauge placed in the 2-3/8" tubing to record bottomhole treating pressure. The actual bottomhole treating pressure record is shown in Figure 9. Changes in slope following shutdown are attributed to three sets of fractures (N48-52E, N37E, N67E). Following nitrogen treatment, the well was flowed for 20 days monitoring hydrocarbon flow rate. Initial flow rate was stabilized at 11 mcfd for Zone #1, similar to Zone #6. In the data frac test, less than 500 mcf nitrogen was injected into the formation as compared to 1165 mcf in the Zone #1 low rate-high volume test. The productivity improvement was about 4.5 times in each case. After 15 days of additional flow, the well had returned to its baseline production of 2 mcfd from Zone #1. Therefore, it was concluded that straight nitrogen fracturing treatment in a .25 psi/ft fracture gradient environment would not sustain production.

CO_2 Stimulation

Zone #1 was stimulated down the 4-1/2" casing/2-3/8" tubing annulus with 120 tons of liquid CO_2. During the CO_2 injection, Iodine-131 isotope tracer was injected at the low rate (12 bpm) while scandium-46 isotope tracer was injected during the higher injection rate (20 bpm). Maximum surface treating pressure was 2642 psi, while the maximum bottomhole treating pressure was 1181 psi when injection rate reached 20.7 bbls/min. Instantaneous shut-in pressure was 958 psi (based on wireline--conveyed bottomhole quartz pressure gauge). More than 2,000,000 scf of CO_2 was injected into the formation. The first 200 barrels of liquid CO_2 was injected at 12 bbl/min rate, while the last 400 barrels were injected at a rate of 20 bbls/min. The well was opened to flow back 5 hours after the job was completed.

The next day after the treatment, the flowing pressure was 180 psi and the estimated flow rate was 83 mcfpd. The well was blown down completely and the downhole pressure gauge was pulled from the hole. The 2-3/8" tubing which had been run in to a depth of 4100 feet was pulled out and a 3" spectral gamma ray tool with special wet connection system was installed on the end of the tubing. The tubing was then run inside the 4-1/2" casing to a depth of 3497 feet, where a 2-3/8" side door sub was placed in the string and the latching head dropped down and connected with the spectral gamma tool. The tool was tested and was found to be functioning properly and the tubing run all the way into the well. After logging one 30-foot joint, the tubing slips moved and crushed the wireline and the assembly had to be pulled out of the well; 6000 feet of wireline cut off and the process started all over again. Logging was finally completed the next day. A plot of bottomhole treating pressure from the downhole quartz pressure gauge is shown in Figure 10.

Results of the tracer log evaluation indicate that 51 fractures out of 69 fractures detected by the video camera investigation of the wellbore were apparently pumped into during the CO_2 treatment. Tracer material was also found in Zone 2-3 compared to the tracer log evaluation in Zone #6. Different fractures and areas along the wellbore were affected by different injection rates.

The initial production rate of 83 mcfd from Zone #1 after straight CO_2 treatment stabilized at 55 mcfd, representing more than a 20-fold increase over baseline conditions. However, after a few days of interrupted shut-in and subsequent simultaneous production of Zone #1 and Zones 2-8, the production rate again started to decline and reached baseline unstimulated flow rates after more than 50 days of production as shown in Figure 11.

A comparison of the CO_2 versus nitrogen treatments indicate that the CO_2 treatment was at least four times better than nitrogen initially and lasted twice as long prior to fracture closure. The density contrast between nitrogen and CO_2 may have caused the propagation of more and wider fractures with CO_2 resulting in high improvement ratios.

During the long periods of flowing Zone #1 while Zones #2-8 were shut-in, zone by zone one hour pressure build-ups in Figure 12 show a systematic pressure transient from Zone #1 all the way back to Zone #6 indicating formation communication. The ECPs were pressure tested between zones after frac treatments and indicated no communication around the elements. Therefore, formation communication is the plausible explanation.

Results to date indicate that proppants are required for low stress fractured shale to sustain gas production beyond baseline conditions. Because

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the production responses to unpropped nitrogen and CO_2 treatments have been measured and subsequently returned to baseline conditions, a meaningful propped stimulation could also be performed on Zone #1. Therefore, a sand-laden treatment was planned and executed.

CO_2 Pad/Sand-Laden N_2-Foam Treatment

The tubing and isolation tool cups were run in preparation for a propped frac treatment down tubing. Results of the CO_2 and N_2 treatments indicate that CO_2 is the preferred base fluid. The ideal frac treatment for water sensitive shale may be a CO_2 pneumatic sand transport stimulation process that would transport sufficient amounts of sand to maintain fracture conductivity without a water base fluid. Such a fracturing process is documented in the international literature[6, 7, 8] but does not appear to be a common practice in the United States. After surveying the literature, little or no published information exist on CO_2-foam sand-carrying characteristics. Therefore, this lack of knowledge resulted in the selection of a hybrid treatment consisting of CO_2 pad followed by sand-laden 85 quality N_2-foam treatment where the liquid phase consists of 7-1/2% methanol and water respectively. Ultimately, a CO_2-based treatment may be preferred.

Zone #1 was re-stimulated with 119 barrel prepad of liquid CO_2 pumped at a rate of 3 bpm followed by 7000 gallons of 85 quality N_2-foam pad injected at 10 bpm. Subsequently, this was followed by 4 stages of .5 to 2.0 lb/gal 20/40 sand. The well started taking fluid at 770 psi and pressured slowly to 1840 psi maximum surface pressure. The 25,000 gallon foam frac was displaced with 9000 scf N_2. Two radioactive tracers were used consisting of antimony-124 injected in the foam pad and iridium-192 pellets in the proppant. A spectral gamma ray log was successfully pumped down with nitrogen in the air filled long horizontal wellbore. It appears to be the first time a spectral gamma ray tool has been pumped in an air-filled 2000 feet horizontal well using nitrogen injection. Evaluation of the tracer log indicates that 43 old fractures accepting fluid during the straight CO_2 treatment were re-opened and propped. Eleven of the 43 received the majority of the proppant. The initial open flow rates of gas from Zone #1 was 34 mcfd against a 55 psig back pressure as shown in Figure 13. A review of Zone #1 pre and post-frac permeability values from well testing analysis indicate an order of magnitude change from .031 md natural to .31 md after the proppant treatment. Permeability values for the nitrogen and CO_2 treatments was .047 and .0485 md respectively.

Horizontal Well Production Responses

The overall production responses for the horizontal well is yet to be determined after the major production zones are stimulated. Both Zones #1 and #6 have had a total of 4 test treatments. Both zones represent only 539 out of 2160 feet of horizontal section available for stimulation. In addition, their total initial unstimulated production represented less than 13% of the total initial production. Therefore, the long-term total production response after stimulation could change dramatically.

Immediately after drilling, total production rate was stabilized at 35 mcfd. The average flow rate for adjacent wells is 12 mcfd. Therefore, the horizontal well was 3 times better than vertical wells in the area. These vertical wells were either produced naturally or borehole shot with gelled-nitroglycerine. The current day rock pressure in both the horizontal well and existing vertical wells are nearly equal.

An effort was made to normalize the production rate and improvement ratio data on an equivalent time after treatment basis as shown in Table 4. A stimulation treatment summary is provided in Table 5. The production rate history for all treatments is also included in Figure 14. The improvement ratios are much higher when CO_2 is used as a base fracturing fluid. The production response was greater with straight CO_2 than with N_2-foam proppant type treatment. However, the CO_2 production went back to baseline while the production from the proppant treatment has been sustained.

CONCLUSIONS

1. Multiple hydraulic fractures can be propagated in a wellbore which has been completed to provide adequate access to multiple natural fractures.

2. Low injection rates during a hydraulic fracturing operation will allow the propagation of natural fractures with a low angle relationship (15° or less) to the principal stress orientation.

3. Higher injection rates generally resulted in inducing fractures controlled by the stress field.

4. Straight CO_2 fracture treatments had the highest initial improvement ratio but could not be sustained in the absence of proppant.

5. Even though stress ratios indicated the area was nearly tectonically relaxed (stress ratio of .28), proppant is still needed to maintain permeable paths for more than 30 days.

6. Multiple hydraulic fractures can be induced from a horizontal wellbore during a single pumping event.

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