SPE
Society of Petroleum Engineers

SPE 19090

Production and Stimulation Analysis of Multiple Hydraulic Fracturing of a 2,000-ft Horizontal Well

by A.B. Yost II, U.S. DOE/METC, and W.K. Overbey Jr., BDM Engineering Services Co.
SPE Members

ABSTRACT

The performance of multiple hydraulic fracturing treatments along a 2000-foot horizontal wellbore was completed in a gas bearing, naturally-fractured shale gas reservoir in Wayne County, West Virginia. Pre-frac flow and pressure data, hydraulic fracturing treatments, and post-stimulation flow and pressure data form the basis from which a comprehensive analysis was performed. Average field production from 72 wells was used as baseline data for the analysis. Such data was used to show the significance of enhanced production from a horizontal well in a field that was partially depleted.

The post-frac stabilized flow rate was 95,000 cubic feet per day (mcf/d) from 2000 feet of horizontal borehole. Under current reservoir pressure conditions, the horizontal well produced at a rate 7 times greater than the field current average of 13 mcfd for stimulated vertical wells. This increase in gas production suggests that horizontal wells, in strategically placed locations within partially depleted fields, could significantly increase reserves.

BACKGROUND

The Federal Government has been investigating the application of high angle and horizontal drilling in tight formations for more than 20 years. The value of high angle drilling and multiple hydraulic fracturing from an inclined or horizontal borehole for maximizing production was recognized in 1969.[1] The first test of the concept was performed by Mobil Oil Corporation in the Austin chalk in which a well inclined to 60° through the pay zone was stimulated three times.[2] The U.S. Bureau of Mines, in cooperation with Columbia Gas and Consolidated Natural Gas, drilled inclined wells in the Devonian shales of West Virginia in 1972[3] and again in 1976.[4] These wells obtained inclinations of 43° and 52° respectively, but production results were mixed and not convincing of the potential for the technique.

The stimulation aspects of horizontal drilling represent a technical challenge in tight formations where the 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 in the horizontal section. Such a completion arrangement provided stimulation intervals with ready-made perforations for injecting fracturing fluids in 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.

A series of stimulations were designed to open and propagate the many known natural fractures that existed along the 2000 foot length of horizontal wellbore. The stimulations were also designed to induce fractures in the formation as well as propagate natural fractures by manipulating pressure and injection rates.

INTRODUCTION

The U.S. Department of Energy's Morgantown Energy Technology Center contracted with the BDM Corporation to select a site, drill, core, log, complete, test and stimulate a horizontal well in the Devonian shales. The area selected for the site was in Lincoln District, Wayne County, West Virginia, as shown in Figure 1. Upon completion of drilling operations which were conducted between October and December, 1986, the RET #1 well was completed, as shown in Figure 2, by installing 8 external casing packers (ECPs) as an integral part of the 4-1/2 inch casing string along with 14 sliding sleeve ported collars which were used to provide access to the formation in lieu of perforations. The casing string was not cemented in place, but anchored by one external casing packer located inside the 8-5/8 inch casing. A cement packer was included in the string as a backup system in case the ECPs failed to inflate; however, 7 of the 8 ECPs pressure tested okay, and thus 7 separate open hole zones were available for testing.

One 4-stage data frac test was conducted in Zone 6 to obtain data on breakdown pressure, closure pressure, fracture gradient and stress ratio for use in designing the primary stimulation test series for the well. Three stimulations were conducted in Zone 1 to determine the most suitable fluid and injection rate; this information was reported in SPE Papers 17759[5] and 18249[6]. Evaluation of the first three fractures pointed the direction for design and implementation of the final two stimulations conducted on the well. The results of these stimulations and the performance of the well upon completion of all stimulations is the subject of this paper.

Pre- and Post-Frac Well Testing and Analysis

The initial well testing phase was initiated with a 640-hour pressure build-up test of the entire 2160 feet (excluding ECPs) of open-hole behind 14 port collars opposite 7 isolated zones. Surface wellhead gauge pressure and orifice meter run pressures were used to establish reservoir permeability.

Classical transient analysis techniques are not strictly applicable to the horizontal wellbore geometry, but was used to obtain initial estimates of reservoir properties to be used as a starting point for the simulation analysis.

The initial/estimated reservoir rock pressure was 192 psia from extrapolation of the Horner plot. It is important to note that the average reservoir pressure in the surrounding wells was determined to be between 188-200 psia based on a 7-day pressure build-up test. The value of Kh was calculated from the following equation:

$$Kh = \frac{1637\, q_{avg} \mu_i Z_i T}{m} \qquad (1)$$

where:
- m = slope = 15863.2
- q_{avg} = average gas production rate, mscfpd
- K = formation permeability, md
- μ_i = gas viscosity, Cp evaluated at initial
- Z_i = gas-low deviation factor evaluate @ initial pressure
- T = formation temperature, degrees R.
- h = formation thickness, ft.

Assuming the whole shale interval (h = 24 ft) to be productive and with a formation temperatu of 93°F, stabilized gas production rate of 35 mcfp and the slope from the Horner plot of 15863. psia²/cycle; therefore formation permeability (K is calculated as follows:

$$K = \frac{(1637)(34)(0.0107)(0.980)(553)}{(15863.2)(247)} = 0.082 \text{ md} \qquad (2)$$

The above estimated value for permeabili is similar to those of a conventional well in low permeability reservoir with a very lar fracture. As discussed previously, these analyse are not strictly applicable to the horizont wellbore geometry, but one may assume a horizont wellbore to represent a vertical well with a lon finite conductivity fracture.

Following the build-up test for RET #1, a attempt was made to isolate and individually te each of the seven zones representing a total interv of 2211 feet (3803-6014 feet). A combinati straddle tool was designed to facilitate the openi and closing of port collars in seven individu zones.

A twenty-four hour pressure build-up te followed by a 24-hour drawdown for each zone w performed using the combination straddle tool. I order to estimate permeability for each isolat zone, a three-dimensional, dual porosity, singl phase gas simulator reservoir model was used t determine permeability values shown in Table 1 The average pre-stimulation permeability was 0.06 md.

Post stimulation analysis of the pressu build-up/drawdown data resulted in determinati of average reservoir pressure values, skin value and average permeability values for the vario zones with the different stimulation jobs. Resul of the pressure build-up analysis using the vario techniques are summarized in Table 2.

Various pressure analysis techniques we used to obtain estimates of post-stimulati permeability. Selective pressure build-up da were analyzed using type-curve matching, Horner' technique, and a newly-developed technique know as the Rectangular Hyperbolic Method (RHM)[7,8].

Post-stimulation analysis for Zone 6 indicate a post-frac permeability of 0.1835 md, but an avera reservoir pressure of 205 psia using history matchi process. Analysis of the pressure build-up da using Horner's technique was not possible due t the fact that the stabilized flow period pri to the build-up test was very short, hence accura results of pressure and permeability could n be determined. Instead, type-curve matching w implemented for the analysis and an average pe meability value was calculated to be 0.1795 m Both techniques indicated similar results, hen

Zone 1 was stimulated by 3 different frac jobs at various treating pressures and rates with nitrogen, liquid CO_2, and nitrogen-foam with proppants. Well testing procedures and data analysis were performed for each job. In the first job when the well was stimulated with N_2, pressure build-up data indicated a reservoir pressure of 290 psia which is above the current average reservoir pressure (185-200 psia as determined by the 7-day shut-in test). This is due to the fact that Zone 1 (N_2 frac) was still overpressured by the amount of inerts present in the gas mixture at the time of testing. The simulation of the pressure buildup data using G3DFR model estimated an average permeability equal to 0.0477 md. Analysis of the pressure build-up data following the second job (CO_2 frac) indicated a permeability value of 0.0480 and 0.0485 using Horner's technique and history matching, respectively. Using Horner's technique, reservoir pressure was estimated at 182 psia. Results of build-up pressure analysis following the third job (N_2-foam-proppant frac) indicated the presence of a dual porosity system with the middle region having a slope one-half that of the late region on the build-up curve which is characteristic of a dual porosity system in the Devonian shale. The average permeability was estimated at 0.090 md, and the average pressure was determined to be 184 psia.

Zones 2-3 and 4 were stimulated using N_2-foam/proppant. Following the cleanup period, Zones 2-3 and 4 produced at a rate of 62 mcfd for a period of 35 days. Pressure build-up analysis using Horner's technique indicated an average reservoir permeability of 0.1505 md and an average pressure of 182 psia.

Zones 5 and 8 were stimulated using N_2-foam/proppant. Analysis of pressure build-up data has indicated an average reservoir pressure of 178 psia and an average permeability of 0.310 md.

Pressure build-up data from Zones 5 and 8 were analyzed using type-curve matching, Horner's technique, and the Rectangular Hyperbolic Method (RHM). Values of average reservoir pressure, formation flow capacity, and skin factor were estimated.

Due to the complexity of production from the Devonian shale and the existence of a dual porosity system, a log-log plot of ΔP^2 (P^2wsPwf), and $d(\Delta P^2)$ (derivative of delta pressure squared) versus Effective Time (Δte) was generated; where $\Delta te = t/(1+ \Delta t/tp)$, Δt = shut-in time (days), and tp = flowing time, 20 days.

The use of pressure-squared approach instead of the pseudo pressure for gas reservoir analysis is proven to be valid for reservoir pressures less than 2000 psia. A Flopetrol Johnson/Schlumberger-type curve was used for infinite acting reservoir with double porosity behavior (pseudo steady state interporosity flow), wellbore storage, and skin. The permeability was calculated from match points at .492 md and skin factor was calculated at 1.386. Using the Horner technique, the permeability was .327 md, average reservoir pressure was 177 psia, and skin factor was -0.881. The Rectangular Hyperbolic Method (RHM) was also utilized to estimate

permeability was .303 md, average reservoir pressure was 178 psia, and skin factor was >0.00. A positive skin value was calculated for Zones 5 and 8, indicating a slightly damaged well. A drop in the skin factor from -2.87 for the overall well to a more positive value for Zones 5 and 8 could be attributed to:

(a) the sand problem that was encountered during the clean-up process, hence indicating damage to the wellbore;
(b) the decrease in the analyzed horizontal section of the wellbore from 2160 feet (all zones) pre-stimulation analysis, to 932 feet (Zones 5 and 8) post-stimulation analysis.

The accuracy of these results was tested using three different techniques. Estimating values of average reservoir pressure ($\overline{P}$) using the RHM technique has an advantage over the conventional methods because knowledge of neither the well/reservoir configuration nor the boundary condition is required for a routine build-up analysis. However, conventional methods such as Horner's technique, when correctly used, will provide superior results of Kh and S values compared to the RHM technique. Therefore, values of K and S for Zones 5 and 8 are believed to be in the range of 0.300 md to 0.492 md and -0.881 to 1.386, respectively, whereas the average reservoir pressure is calculated at 178 psia based on the RHM technique.

Well Stimulation Summary

The objective of stimulation research in the horizontal wellbore 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 buildup test data were used to determine permeability-thickness product and flow rate improvement ratio. Key stimulation issues identified were:

(1) the number of fractures that could be opened and propagated during a single hydraulic fracture pumping event;
(2) whether proppant would screen out easier in a horizontal well;
(3) understanding what determines which natural fractures are propagated;
(4) determining the best fracture diagnostic system to use in a horizontal well;
(5) understanding how to place proppants and the volumes required;
(6) understanding the need or value of pad volumes when treating multiple fractures at the same time.

The overall technical approach was to:

(1) induce multiple hydraulic fractures,

(2) determine how many and where fractures were induced in the borehole;
(3) evaluate hydraulic fracture design for a horizontal well in shale formation;
(4) 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. In addition, the consideration of other joint systems having nearly parallel orientations which would either act as leakoff areas or actually accept fracture fluid under propagating conditions. Each zone available for stimulation had numerous natural fractures which would accept fracturing fluid. An open hole type completion technique using external casing packers and port collars was used to isolate zones with different stimulation potential.

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. Zones 6 and 1 were selected for testing. Zone 6 had very few fractures and was selected for the mini frac tests, while Zone 1 had many fractures and was selected for frac fluid testing. 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 injection 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.

Data fracs were conducted on Zone 6 using a computerized data acquisition system. From this series of tests, closure pressure (or parting pressure) was determined to be 850 and 1050 psi. The lower pressure is postulated to be the closure pressure for a natural fracture, and the higher pressure for an induced fracture. The fracture gradient was calculated to be 0.25 psi/ft of depth for Zone 6. The ratio of minimum horizontal stress to vertical stress was calculated to be 0.22.

The first of five full-scale stimulations on the horizontal well was conducted on Zone 1 with nitrogen gas fluid. The gas was injected at slow wellbore. Initial open flow rate of 80 m declined rapidly so that the well was making baseline rate after 20 days.

The second full-scale stimulation was conducted in Zone 1 since it was felt that a be comparison of fluids would be more realistic meaningful if all tests were conducted in the zone. The second fluid was liquid CO_2, which a cryogenic fluid, pumped at 0°F, and at press about 200 psi above closure pressure. stimulation was conducted in two stages, pu at two different rates, with considerable differ in the results in terms of the number of fract inflated. More fractures were inflated at higher injection rates. In addition, the produc improvement ratio was higher with CO_2 when comp to nitrogen gas and nitrogen foam as fluids. Ini production was more than 250 mcfpd, however, a more than 50 days of production, the rate declined again to the original rate of 2.2 mc One plausible explanation is that without propp the fractures opened up and simply closed time.

This experience of losing production bec of closing fractures led us to conclude that prop was a necessary ingredient in the stimulation des The third stimulation was a small volume nitr foam stimulation pumped in two stages (#1 #2 proppant), but at the same rate of 10 bbls/min Two different radioactive tracers were used determine where fractures were being propag along the wellbore. Forty-six (46) fractures opened and propagated. After cleanup, the produc was sustained due to the use of proppant.

The fourth stimulation was conducted in 2-3 and 4 combined. After the results of #3, it was felt that we needed to see if a l volume fracture over about the same length wellbore would give a proportionate increase production rate. The large volume fracture consi of 4500 gallons of liquid CO_2 as a prepad, 44 gallons of pad, and 90,000 gallons of 80-qua foam containing 250,000 pounds of sand (2.5 lbs/ all pumped at 50 gallons per minute downhole rate. There were some difficult sand cle problems after this frac job. The improve ratio of stimulated production to natural produc was 3.1 to 1. Zone 4 was the zone with a natural show of 2.16 million scf of gas per and was a major fault and fracture zone. A sum of the stimulation treatment schedule for No is shown in Table 3 and the production his after stimulation is shown in Figure 3.

The fifth and final fracture was a scaled- version of Frac No. 4. The final treatment cov almost twice as much borehole (930 feet) in Z 5 and 8 versus 590 feet in Zones 2-3 and 4 du Frac #4, but pumped only 105,000 gallons 85-quality foam and 150,000 pounds of sand at barrels per minute rate. Sand cleanout prob were not as severe this time. Gas produc improvement ratio for the combined zones was to 1, which was an improvement over Frac #4 Zones 2-3 and 4, but not in the same class as #3 with its 15.5 to 1 improvement ratio.

A summary of the stimulation treatment schedule for No. 5 is shown in Table 4 and the post-stimulation production is shown in Figure 4. A summary of all stimulation treatment fluids, rates, volumes, and diagnostics is shown in Table 5.

Productivity Improvement

As a result of the different frac jobs in the various zones, the production was enhanced in all zones. This improvement in production is reflected in the increase in flow rates and a decrease in skin factor values. Following stimulation No. 5, frac sand and plugs were removed from the entire 2000 foot section and the well was placed on production at 155 mcfd. Both reservoir simulation and average current day production from 72 wells in the field indicate that stimulated vertical wells are currently averaging 13 mcfd. Pre-frac stabilized flow rate from the horizontal well was 35 mcfd. A summary of individual stimulation improvement ratios for frac No. 1 and 2 went to zero beyond 40 days of flow due to the lack of proppant in the treatment. Overall, the productivity improvement ratio ranged from 2.9 to 11.8 based on 40 days of production.

The improvement in skin value is a qualitative measurement of the productivity improvement. In addition, this improvement is indicative of the conditions around the wellbore which is translated into an increase in the surface area contributing to production due to the stimulation process. A negative skin indicates a stimulated wellbore; hence, a successful stimulation.

In the horizontal well, the pre-stimulation skin value was estimated at -2.87 due to the geometry of the wellbore (horizontal well), since horizontal wellbores are equivalent to stimulated reservoirs. The skin values showed an improvement for Zones 1, 2-3, and 4, whereas a decrease in skin from -2.87 to -0.881 was detected in Zones 5 and 8. This could be due to presence of sand in the wellbore or formation damage as a result of the frac job.

An additional method of analyzing stimulation effectiveness is the examination of permeability improvements. Table 7 provided data on the post-frac permeability compared to the pre-frac permeability. Improvements ranged from 1.79 to 4.4 with an average ratio of 3.2.

The production decline curve for the horizontal well is shown in Figure 5. The stabilized flow rate was 95 mcfd representing a 2.7 fold increase as a result of hydraulic fracturing. The horizontal well is currently producing 7 times more than a vertical well based on simulation and the 72-well average flow rate for the field.

The G3DFR model was used to predict/project a 20-year history of production based on estimated values of reservoir pressure, formation thickness, and average permeability. The average reservoir pressure and formation thickness were kept constant at 182 psia and 247 feet, respectively, due to the fact that geologic and engineering data were sufficient to accurately estimate these values. Post-stimulation permeability was calculated to be 0.200 md.

It is believed that a permeability value of 0.2 md is representative of the formation's permeability. When permeability anisotropy (R) equals 1:1, the first year's average production rate was projected at 83 mcfd, when R = 1.2 (Kx:Ky), the first year's average production rate is projected at 97 mcfd. Plots of cumulative production versus time for different anisotropy ratios are shown in Figure 6. In addition, a plot of the 20-year projected production rate versus time is shown in Figure 7.

The G3DFR model was used to evaluate the potential production from the location prior to drilling the Recovery Efficiency Test No. 1 well and was also used to predict production of the well after drilling and stimulation was completed. Figure 8 projects 20 year cumulative production for the RET #1 well utilizing developed parameters from well testing of 180 psia pressure. Using the full reservoir thickness of 247 feet as productive reservoir, we found that we had to reduce the permeability to an average of 0.09 md to match the current rate of production. This indicates that there are most likely heterogeneities in the fracture system and that the flow path to the wellbore is not consistent. It is likely that the fracture permeability changes with time as fractures slowly close as pressure declines with production. This would seem to be one argument in favor of holding a back pressure on the formation during production.

Figure 9 compares the final projected production and decline curve with the pre-drilling estimate. The difference in the projections was primarily the difference in pressures used. The pre-drilling model used 350 psi reservoir pressure, while the post-drilling projection used 180 psia. Pre-drilling model studies also projected a vertical well, drilled at the site where the horizontal well was drilled, would produce 80 mmcf in 20 years. This comparison indicates the horizontal well should produce 7.8 times more gas than a vertical well drilled at the same location.

CONCLUSIONS

1. This 2000 foot horizontal well in fractured Devonian shale has successfully demonstrated numerous folds of increase in production as compared to vertical wells in a pressure-depleted producing field.

2. Productivity improvements were successfully evaluated by actual flow rates, build-up analysis, and skin factor calculations.

3. This project represents the most extensively documented zone-to-zone production and stimulation testing of a long horizontal well in a naturally-fractured gas reservoir.

4. Both long horizontal drilling and multiple stimulations are required to achieve high folds of increase in production.

DOCKET ALARM

Explore Litigation Insights

Docket Alarm provides insights to develop a more informed litigation strategy and the peace of mind of knowing you’re on top of things.

Real-Time Litigation Alerts

Keep your litigation team up-to-date with **real-time alerts** and advanced team management tools built for the enterprise, all while greatly reducing PACER spend.

Our comprehensive service means we can handle Federal, State, and Administrative courts across the country.

Advanced Docket Research

With over 230 million records, Docket Alarm’s cloud-native docket research platform finds what other services can’t. Coverage includes Federal, State, plus PTAB, TTAB, ITC and NLRB decisions, all in one place.

Identify arguments that have been successful in the past with full text, pinpoint searching. Link to case law cited within any court document via Fastcase.

Analytics At Your Fingertips

Learn what happened the last time a particular judge, opposing counsel or company faced cases similar to yours.

Advanced out-of-the-box PTAB and TTAB analytics are always at your fingertips.

API

Docket Alarm offers a powerful API (application programming interface) to developers that want to integrate case filings into their apps.

LAW FIRMS

Build custom dashboards for your attorneys and clients with live data direct from the court.

Automate many repetitive legal tasks like conflict checks, document management, and marketing.

FINANCIAL INSTITUTIONS

Litigation and bankruptcy checks for companies and debtors.

E-DISCOVERY AND LEGAL VENDORS

Sync your system to PACER to automate legal marketing.

WHAT WILL YOU BUILD? | **sales@docketalarm.com** | **1-866-77-FASTCASE**