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Drilling a 2,000-ft Horizontal Well in the Devonian Shale

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ABSTRACT

This paper discusses drilling a 2,000-foot horizontal well in the Devonian Shale, Wayne County, West Virginia, to test the concept that multiple hydraulic fractures from a horizontal wellbore can increase gas recovery efficiency over vertical stimulated boreholes. Discussion focuses on the air/mist drilling, wireline probes, and bottomhole assemblies that were used to drill the well. The target was a 50-foot zone located at a depth of 3,400 feet. Total hole length was 6,020 feet. The angle-building section was achieved using a 4.25°/100-foot design to reduce the risks associated with casing installation in the horizontal section. Directional control methods proved to be unreliable in an air-drilling environment. Bottomhole assembly performance was heavily dependent on motor life and lithologic type. The completion program for the well consisted of installation of 4 1/2-inch casing with external casing packers and port collars. This completion string was installed in 2,000 feet of open hole section that was air drilled. Both geophysical well logs and a borehole television camera survey were used to design the casing string so that shale intervals could be isolated for testing and evaluation before and after stimulation.

BACKGROUND

The drilling of directional wells and even horizontal wells to augment oil and gas production goes back to at least 1944 in the Appalachian Basin wherein a horizontal well was drilled from a 500-foot deep shaft in the Franklin Heavy Oil Field in Venango County, Pennsylvania, to improve oil recovery. Several hundred feet of horizontal core was taken during the drilling operations in the Venango Sand to characterize the reservoir.

References and illustrations at end of paper.

The Federal Government has been investigating the application of high-angle drilling to improve reservoir access in tight formations for more than 20 years. The focus of much of this research was to determine the properties of earth fracture systems in productive Devonian shale reservoirs and to develop improved techniques for recovering hydrocarbons with increased efficiency. The value of high-angle drilling perpendicular to natural fracture systems for maximizing production from fractured reservoirs was recognized early[1]. Several field tests have been conducted to investigate the concept. In 1972, a high-angle borehole was drilled in Mingo County, West Virginia, to a measured depth of 4,678 feet with an average deviation of 41° from vertical through the Devonian shale section[2]. After establishing the feasibility of drilling high-angle wellbore using air, a subsequent well was drilled to 53° in the Cottageville Field, Jackson County, West Virginia[3,4]. Total measured depth of that well was 4,736 feet. Experience from these two directional wells using mud motors on air identified many limitations of economic directional drilling. In DOE's latest experience, an oriented core was obtained from a Meigs County, Ohio, Devonian shale directional well to determine natural fracture spacing[5].

High-angle air-drilling experience using downhole motors is not well documented in the petroleum literature. The most recent experience in air-drilled high-angle wells is the Grand Canyon Directional Drilling and Waterline Project[6] which was accomplished using air-driven motors and wireline steering probes. Conventional wellbore sizes and tools were used to achieve a 71° hole angle.

Recent reservoir modelling studies used to estimate recovery efficiency of a Devonian shale horizontal well show a two- to three-fold increase in gas reserves per unit volume of reservoir[7].

INTRODUCTION

In 1985, the Department of Energy's Morgantown Energy Technology Center awarded a contract to BDM Corporation to test the concept that multiple hydraulic fractures from a high-angle wellbore can increase Devonian shale gas recovery efficiency over that of vertical wells. BDM selected Grace, Shursen, Moore, and Associates (GSM) to consult on wellsite drilling activities because of their experience in the Grand Canyon well. The project team consisted of DOE, BDM, and GSM personnel to design and execute the major field experiment.

Based on the results of prior Appalachian Basin air-drilled directional wells, key technical issues of concern were:

- Turning a well beyond 55° in hard rocks.
- Maintaining adequate directional control of well.
- Determining the optimum rate of angle build in hard rocks.
- Reducing friction and drag during drilling.
- Keeping the wellbore cleaned at high angles.
- Adapting logging tools to operate in high-angle wells.
- Completing the well in the horizontal section.
- Isolating zones for testing and for applying multiple stimulations.

Site selection was considered to be one of the most important elements of the program. A site was selected in the Wilsondale Pool, Wayne County, West Virginia, because of the availability of knowledge of the regional natural fracture network[8]. These data were used to design the wellbore azimuth for drilling and for predicting areas of high fracture permeability. Full-field simulation was required to accurately predict well performance and interference effects inside the Wilsondale Pool. The Wilsondale Pool area was selected after carefully screening normalized cumulative production data from several Devonian shale producing areas as shown in Figure 1.

Well planning was aided by a desk-top computer program which was used to perform drill string analyses for drilling rig and equipment sizing. An on-site portable computer aided in daily spreadsheet tracking of well trajectory and costs as well as in comparing actual drilling data with model predictions[9].

WELL PROGNOSIS

After careful review of the risks of slim hole drilling and air drilling techniques used in the Grand Canyon well, the following well prognosis was developed:

1. Drill a 17 1/2-inch (or 18-inch) hole to 630 feet.

2. Run and set 630 feet of 16-inch conductor pipe.

3. Cement to surface. Wait on cement 8 hours.

4. Drill a 14 3/4-inch hole to 2,000 feet using air and mist (approximately 3,500 scfm).

5. Run and set 11 3/4-inch, 47#, J-55, ST&C casing.

6. Cement back to 1,300 feet.

7. Nipple up wellhead and rotating head.

8. Drill out with a 10 5/8-inch bit.

9. At 2,080 feet, run a 10 5/8-inch air bit, 7 3/4-inch Baker motor, 2 1/2° bent sub, 8-inch Monel, MWD, two 8-inch drill collars, and 4 1/2-inch drill pipe.

10. Directionally drill at 4.25°/100 feet. (If the 2 1/2° bent sub does not give 4.25°/100 feet, use a 3° bent sub or a bent housing motor in combination with a bent sub.)

11. Drill to 85° to 90° at a total vertical depth of 3,423 feet (50 feet from bottom of lower Huron) which should be approximately 4,080 MD.

12. Circulation rate should be 2,500 cfm with < 10 bbls/hr mist.

13. At times it may be necessary to make reaming runs to bring the hole into gauge. If this is necessary, run a bit, 3 point, 8-inch Monel, 3 point, and two 8-inch drill collars. Ream this assembly through the portion of the hole causing problems.

14. Log the well using conventional wireline tools to the free fall point.

15. Run and set 8 5/8-inch, 24#/ft and 28#/ft, J-55, ST&C casing at ± 4,800 feet.

16. Cement the bottom of casing conventionally. Place 10 feet of sand in annulus and fill annulus with Class "A" cement. Wait on cement 8 hours.

17. Nipple up wellhead, bag preventer, and rotating head.

18. Drill out of 8 5/8-inch casing with a 7 7/8-inch bit, 3 point, and Monel drill collar.

19. Core 60 feet of the lower Huron at 85° to 90°.

20. Ream out core hole with 7 7/8-inch bit, 3 point, and Monel with MWD. Drill ahead until a motor correction is required or total depth is reached.

21. Run a 7 7/8-inch air bit, 6 3/4-inch motor with bent housing, 6 1/4-inch Monel, and 4 1/2-inch drill pipe to make a motor correction.

22. Drill 2,000 feet of horizontal hole in the lower Huron using air-drilling only with a minimum of 2,400 cfm.

23. At total depth, log and test the well.

24. Run and set 4 1/2-inch, 10.5#/ft J-55, ST&C at total depth using external casing packers, completion packer, and port collars.

DRILLING

Drilling operations were conducted at the selected site between October 21 and December 18, 1986. Figure 2 shows a plot of depth versus days for the actual and planned drilling program. The actual drilling program took 58 days to complete. The planned drilling time was 45 days.

The major difference in drilling time was consumed in the vertical portion of the hole. The estimated drilling time was 3 days and it actually took 15 days. The directional portion of the hole was planned at 42 days and required 43 days. The building portion of the well took longer than expected because of two sidetracks; however, the horizontal section went faster than expected because no motor corrections were required. Drilling progress by activity is described in Figure 3.

Based upon the logs and the actual kickoff point of 2,113 feet, the rate of build was changed from 4.25° per 100 feet to 4.48° per 100 feet. The horizontal target total vertical depth was changed from 3,420 feet to 3,390 feet ± 10 feet based upon the logs and the actual elevation. The inclined section of the hole was built from vertical to 92° in the interval of 2,113 feet to 4,043 feet. This section was drilled with a 10 5/8-inch bit and 8 5/8-inch casing was run to 3,803 feet.

Directional drilling began using a 7 3/4-inch low-speed motor on an air/mist system, a 2 1/2° bent sub, and an electromagnetic MWD system. Progress was slow at first because of problems associated with motor plugging and with the MWD system. The MWD system was switched to a wireline, flux gate tool. The initial build rate averaged 4.75° per 100 feet to 2,800 feet. The dogleg severity averaged 5.25° per 100 feet. After 2,800 feet, the rate of build decreased to 3.5° per 100 feet at 3,182 feet. The inclination in the same interval changed from 35° to 48°. Above 48°, the build rate started to increase slightly, but the motor failed after the survey at 3,246 feet. Since the inclination was beginning to lag the planned trajectory, a 3° bent sub was run with the next motor at a depth of 3,309 feet.

This assembly drilled a section of hole that had an average build rate of 7.4° per 100 feet. After only two surveys with the 3° assembly and a projected inclination of greater than 68°, the assembly was pulled out of the hole because the inclination was building too fast. The measured depth at this point was 3,509 feet. The hole was found to be tight when tripping out and reamers were run to ream the hole out. The hole required reaming from 2,230 feet to total depth. While making the connection on bottom, the drill pipe became plugged and stuck. Attempts to fish the bottomhole assembly were unsuccessful and the well had to be sidetracked. The well was plugged back to 3,175 feet with cement and the cement was dressed off to 3,239 feet.

A 7 3/4-inch motor with 2 1/2° bent sub was run to sidetrack out the right side of the hole. In sidetracking, the well dropped inclination and then did not build fast enough to regain the lost angle. The well had actually sidetracked while dressing off the cement plug because the inclination had dropped from 51.6° to 48° at 3,240 feet. The cuttings were almost all shale when drilling with the downhole motor began. At 3,421 feet, a 3° bent sub was run to build inclination faster. At this point the inclination would have to be built at about 7° per 100 feet in order to be 90° within the target total vertical depth. The assembly built angle erratically ranging from 4.4° to 6.9° per 100 feet. At 3,666 feet, it was determined that the target could not be hit without building over 10° per 100 feet. Because this build rate was not likely, the well was plugged back and sidetracked again. Position of the sidetrack relative to the planned trajectory is shown in Figure 4.

The well was plugged back to 3,330 feet with cement. The cement was dressed off to 3,362 feet where the second sidetrack was initiated. In order to kick off on the high side of the hole, a strong building assembly was run. The assembly consisted of a 2° bent housing (6 3/4-inch OD) motor and a 1.5° bent sub. The assembly had no problem sidetracking out the top side of the hole.

Directional drilling continued to 3,827 feet when hole cleaning problems dictated running the 8 5/8-inch casing. Several days were spent trying to clean the 10 5/8-inch hole with as much as 4,000 scfm of air and 30 bbls/hr of mist. During one of the reaming runs, a single shot survey was run and indicated that the inclination was 74° rather than the 76° the steering tool was reading. The survey at 3,787 feet was changed to 74° from 76.3° to reflect the single shot data.

A string of 8 5/8-inch, 24# and 32#/ft, K-55, ST&C casing was run and cemented in place at 3,803 feet (Kelly Bushing). The casing ran without incident to a depth of 3,543 feet at which point the casing stopped and had to be washed down several places thereafter. No problems were encountered in running tools through the heavy walled casing.

The next building assembly consisted of a 6 3/4-inch bent housing motor. The bend in the motor was set between 1 3/4° and 1 7/8°. This is the maximum bend that could be put into the 8 5/8-inch casing without having to push it with the drill collars. A 2° bend probably could have been run in the 8 5/8-inch casing, but was not required since the smaller bend built adequately.

The average dogleg severity for the bent housing motor was 10.1° per 100 feet. At a measured depth of 4,043 feet, the extrapolated inclination was 92°. The angle build portion of the hole was complete. The true vertical depth of the well was 3,402.5 feet which was 2.5 feet below the specified target. Figures 5 and 6 compare planned versus actual drilling performance for the inclination and azimuth of the borehole.

Bottomhole Assemblies

The average build rate obtained with the 2 1/2° bent sub while drilling the 10 5/8-inch hole was 5.6° per 100 feet. The 3° bent sub built at an average of 7.36° per 100 feet. The expected build rates for the 2.5° and 3° bent subs were 5.5° per 100 feet and 7° per 100 feet, respectively, very close to the actual values.

The second sidetrack used a 2° bent housing motor (6 3/4-inch OD) and a 1.5° bent sub. A 2° bent housing in a 10 5/8-inch hole should yield an angle building rate of about 5.5° per 100 feet and a 1.5° bent sub should yield 2.5° per 100 feet. If the values are additive, the expected build rate should be 8° per 100 feet. The actual build rate was 7.72° per 100 feet for the first motor run, but only 4.25°

per 100 feet during the second run. Figure 7 compares different BHA's used for building inclination.

After the 8 5/8-inch casing was run, a 6 3/4-inch bent housing motor with a 1.8° bend of the housing was used. The expected rates of build in a 7 7/8-inch hole for the motors used are not published or available from the manufacturer; however, a 1.5° bent housing should yield a 5° per 100-foot rate in an 8 3/4-inch hole. Extrapolating, a 1.8° bent housing should yield about 7° per 100 feet in the 8 3/4-inch hole. The reduced hole size could be expected to add at least 1° or 2° more. The actual build rate for the last two motor runs was 9.8° per 100 feet, very close to the expected value.

A total of 14 motor runs were made using 11 downhole motors as shown in Table 1. The average footage drilled per motor run was 176 feet in 7.8 drilling hours. The average footage drilled per motor was 224 feet in 9.93 drilling hours. Seven 7 3/4-inch and four 6 3/4-inch motors were used. Time spent restarting the motors averaged 2.71 hours per run and 3.45 hours per motor. This is the time it took to restart the motor after it stalled or after a connection. There were only a few times the motor stalled while drilling. The eventual procedure that worked best for restarting the motors was to pump a few barrels of water (containing mist chemicals) down the drill pipe prior to turning air into the drill pipe. This restarting procedure increased motor life by 1.5 to 2 times. After a while, even that would fail to restart the motors.

Attempts were made to determine the cause of the poor motor performance. The air rate was varied between 2,000 and 3,000 scfm, the mist rate was varied between 5 and 35 barrels per hour, and each chemical in the mist except soap and polymer was dropped out of the mist one at a time as presented in Table 2. Nothing seemed to have any effect on the motor performance. When the motors were sent back for repairs, no mechanical damage was found.

Directional Survey Implementation

The first system used for steering the downhole motors was an electromagnetic measurement-hile-drilling (MWD) unit. This wireless device transmitted data back to the surface by electromagnetic radiation. The first MWD probe failed at the end of the first motor run after only 4 hours drilling time. While restarting the motor, the stand pipe pressure went up to 500 psi and the O-ring seals in the MWD probe failed.

The second electromagnetic MWD probe quit working after 4 hours. The motor was tripped out and the electronics package replaced with the last backup package. Operating problems in shutting off the airflow to transmit tool face data required the abandonment of the electromagnetic probe in favor of the wireline flux gate system.

The wireline flux gate type steering tool was used from 2,277 feet to the completed angle build point at 4,043 feet. A side-door entry sub was used to transfer wireline outside the drill pipe. The probes operated very well at air rates of 2,100 scfm, but experienced failures at air rates above 2,100 scfm.

A magnetometer/accelerometer type probe was run at the beginning of the first sidetrack. The first probe lasted 2 hours, and the second probe lasted 3 hours. The air rate was 2,100 scfm while running this type probe. After these probe failures, the flux gate probes were used until 8 5/8-inch casing point was reached.

Final angle building (75° to 90°) was achieved using flux gate probes for tool face and single shots were used to monitor inclination and direction. The biggest problem with the side entry sub was kinking the wireline, which is to be expected.

Hole Cleaning

As expected, hole cleaning was one of the major problems in drilling the well. The intent was to start out at a minimum air rate of about 2,000 scfm with as little mist as possible. The minimum mist pump rate was a little less than 10 barrels per hour. The first two motor runs ended with the bit plugged with cuttings even though there was a float immediately above the motor.

At the end of motor run No. 6 (3,309 feet), a problem was experienced in pulling the drill string out of the hole. The hole was tight after pulling one stand (60 feet). Air was circulated for 1 1/2 hours to clean the hole. The inclination at 3,300 feet was 54°. On the next motor run, there were a lot of problems getting out of the hole at 3,509 feet. The inclination was 65°. The hole could not be circulated clean, but the pipe could be pulled out of the hole with little or no drag as long as the air was circulating. The air stream made a fluidized bed of the agglomerated cuttings and allowed the drill string to move freely.

At 3,509 feet, a reaming run was made to clean the hole out. The reaming assembly became stuck during a connection at 3,509 feet. While making a connection, the pipe became plugged and would not come out of the hole. It was not known at this time, but the inclination between 60° and 70° is the point where the majority of the hole cleaning problems were encountered. The air rate was 3,150 scfm while reaming near the bottom.

The well was plugged back to 3,200 feet in order to sidetrack the fish. The cement was drilled out with 2,100 scfm and 20 barrels per hour mist. Then the well was sidetracked with the same air and mist rate. There was no problem getting out of the hole. The inclination was around 47°.

At 3,330 feet the air rate was increased to 3,150 scfm with 20 barrels per hour mist to increase hole cleaning. However, air rate had to be reduced after 121 feet of drilling due to four probe failures. At this depth, the motors had to be washed back in the hole indicating that hole cleaning was not adequate. The inclination at this point was about 57°. Drilling continued with 2,100 scfm to 3,666 feet. The drill pipe had to be pumped out of the hole on the trip at 3,666 feet. The inclination was a little over 60° at this point. A reaming run was made to clean the hole out. After reaming the hole and circulating for 1 1/2 hours with 3,150 scfm and 20 to 25 barrels per hour mist, the drill string still had to be pumped out of the hole.

On the trip out of the hole at 3,634 feet, there was a little drag, and there was 60 feet of fill on bottom of the trip. At 3,700 feet, the pipe had to be pumped out of the hole. The inclination at 3,800 feet was 74°. Even after circulating at 4,200 scfm and working the pipe for 2 hours, the pipe still had to be pumped out of the hole. Because of the hole cleaning problem, the decision was made to run the 8 5/8-inch casing. Two (2) more days were spent trying to clean the hole and the casing still had to be circulated into the hole.

HORIZONTAL DRILLING

The last motor run finished with an inclination of 92°. The wellbore had reached 90° at 4,020 feet. The well was cored and drilled to 4,156 feet using mist and 2,100 scfm of air.

After coring operations were complete, the wellbore was dried up and the rest of the well was dusted with no further problems associated with hole cleaning. The assembly run was a bit, float sub, bottomhole three point reamer and two 6 1/4-inch Monel drill collars with a Monel crossover sub between the Monels. The assembly turned out to be perfect for the drilling of the horizontal section of the hole. It dropped inclination at an average rate of 1/4° per 100 feet and walked to the right at 1/2° per 100 feet. The final total vertical depth reached was 3,427 feet which was 25 feet from the bottom of the lower Huron shale. A little more dropping tendency (an additional 0.1° per 100 feet) could have dropped the wellbore to the bottom of the lower Huron. Considering the ability to control BHA's, the assembly did an excellent job. From the plots of the vertical and plan view (Figures 5 and 6), the wellbore course was on target better than could be expected considering no motor corrections were made.

The weight of the BHA was adjusted from 25,000 to 15,000 lbs in an attempt to make the assembly drop a little faster; however, bit weight had no effect on the dropping tendency of the assembly. Subsequently, the bit weight was maintained at 20,000 lbs with a penetration rate of 25 feet per hour including connections.

The bottomhole assembly analysis program had also indicated that bit weight would have no effect on the inclination tendency. The program gave a bit side force of 1,584 lbs build and a bit tilt of 0.08°. Both indicate the assembly should have built inclination when in fact it dropped inclination. Therefore, the formation had a drop tendency equivalent to the building tendency of the assembly plus about 0.3° per 100 feet.

Coring

The 7 7/8-inch hole was cored after angle building had been completed to an inclination of 92°. A standard 30-foot, 6 1/4-inch diameter core barrel modified with an inner tube stabilizer in the center was used to core the well. The core bit was a 7 7/8-inch by 4-inch compact bit (RC-444). An aluminum inner barrel cut in 15-foot lengths was used because of the center stabilizer. All the cores were oriented so the direction of the natural fractures could be determined. The first oriented core was taken from 4,043 feet to 4,056 feet. The second oriented core was made from 4,056 feet to 4,086 feet with no problems. Rotary drilling continued to 4,126 feet where an additional 30 feet of oriented core was obtained. Table 3 summarizes core recovery, number of fractures, and their orientation. Fracture observed from the core verified the planned orthogonal azimuth of the horizontal wellbore.

Hole Drag

The most significant problem in the horizontal section of the hole was hole drag. Hole drag did not become a problem until a depth of 5,400 feet was reached. The problem occurred when running the pipe back in the hole after a connection. All the weight could be slacked off and the pipe would not go down but could be pulled up and rotated easily. To solve the problem, six 6 1/4-inch drill collars were placed in the vertical hole at 1,500 feet on the next bit trip.

All the data indicated that an initial coefficient of static friction had to be overcome before the pipe could start moving. Once the pipe was moving, then only the lower coefficient of kinetic friction had to be exceeded. By using the momentum of the drill pipe (dropping the drill string from maximum hook load), the higher friction coefficient could be overcome.

Below 5,400 feet, the variables for drill string drag going down had to be changed. As can be seen in Table 4, the coefficient of kinetic friction while lowering the drill string changed significantly while the hoisting and rotating coefficient did not change much. A computer model was used to calculate the coefficient of friction. The friction coefficient was varied until the drag value equaled the drag measured in the field.

When the bottomhole assembly was left out of the drill string while running logs, there was no problem getting the drill pipe in and out of the hole. The excessive down drag in the bottom of the hole had something to do with the BHA. The excessive drag could have been caused by drill pipe buckling.

WELL LOGGING

After reaching total depth, the 7 7/8-inch hole was logged with an open hole logging suite and a downhole television camera. A drill pipe conveyed logging system was used to log the hole in two logging runs. The logging tools are encased in a housing which attached to the bottom of the drill pipe as shown in Figure 8.

The first logging run was a gamma ray, density, caliper and dual induction suite. The density and caliper tools did not work properly because the pad was located on the low side of the hole and did not position the tool to contact the hole properly.

The second logging run was a temperature and gamma ray tool. The temperature was logged while tripping in the hole. The gamma ray tool (which was being run for correlation purposes) failed, so the 8 5/8-inch casing seat was used for depth correlation for the temperature tool.

From examination of the logs, the temperature log should be the best log for detecting fractures and/or production on the horizontal wellbore of a Devonian shale well. The relationship to gas shows and temperature log anomalies is presented in Figure 9.

A downhole television camera was run and proved to be very useful in identifying the fractures in the wellbore. This is the first time a television camera had been run using the drill pipe conveyed logging method. Video log analysis detected more than 250 features interpreted to be fractures. Many of those features contained stains indicating condensate bleeding into the wellbore at that point.

In the interval 5,042 feet to 5,055 feet, a distance of 13 feet, 14 fractures were detected giving an average spacing of 0.9 feet between fractures. This same zone also produced a gas show calculated at 2,219 mcfpd.

The number of observed features interpreted to be natural fractures varied from a low of 5 for a 200-foot interval (4,500 feet to 4,700 feet) to more than 40 (5,100 feet to 5,300 feet, as shown in Figure 10). The frequency of occurrence of fractures increased in the back section of the borehole varied from a few inches to 70 feet. The mean spacing for fractures over the 2,200-foot length surveyed was 8.8 feet.

CASING PROGRAM

After reaching a total depth of 6,020 feet and completing open hole logging operations, casing operations were initiated. Though operations were slow, there were no problems encountered.

The 4 1/2-inch casing was run to total depth without any problem. A total of 14 port collars, 8 external casing packers, and 1 cement packer were run on the 4 1/2-inch casings. The placement of the packers and port collars can be seen in Figure 11. One centralizer was placed immediately above and below each external casing packer (ECP) to prevent damage while being run in the hole.

The external casing packers were used to isolate the individual producing zones. The cement packer is a backup to the ECP packer and can be inflated with cement. The port collars are located between the packers and will be used to selectively produce and stimulate the individual producing zones. Table 5 shows the specific isolated intervals and the number of port openings available for testing and stimulation.

PROJECT COSTS

This well was planned to accommodate the research objectives of the project, which included horizontal coring and logging and unconventional casing installation. Twenty-five (25) percent of the total costs were for research and development. Nine (9) percent of the costs were for site management. As shown in Table 6, the balance of project costs (66 percent) were third-party costs which were probably lower when the well was drilled than they will be in the future. Well stimulation costs were not included in the analysis.

Overall project costs for commercial application could be reduced by decreasing the turning radius, extending downhole motor life, and development of a more efficient and reliable MWD system for air drilling.

CONCLUSIONS

1. This drilling project has demonstrated that long radius horizontal wells can be successfully drilled in fractured Devonian shale using air drilling techniques.

2. Downhole motor life needs to be extended to reduce drilling costs.

3. The causes of reduced motor life in this well are not understood.

4. Hole cleaning is a major problem while building angle using air/mist driven motors.

5. A reliable measurement while drilling (MWD) tool needs to be developed for angles greater than 60° in air drilled holes.

6. This successful project has demonstrated installation of casing, external casing packers, and port collars along the 2,213 feet of horizontal section for use in multiple well stimulations along the borehole.

7. The well represents the World's first and longest air-drilled horizontal gas well (2,213 feet) to be logged, cored, and cased to permit hydraulic fracturing over multiple zones.

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Table 1
Downhole Mud Motor Performance

MOTOR #	FEET	FT HR	HOURS TO RESTART	BUILD RATE DEG 100	BENT SUB BENT HSG	COMMENTS
1	102	34 0	0 00	4 42	BS 2 5	PLUGGED WITH CUTTINGS
2	62	24 8	0 00	7 86	BS 2 5	PLUGGED WITH CUTTINGS
2	282	25 6	0 50	4 29	BS 2 5	MOTOR FAILED
1	45	12 9	0 50	5 87	BS 2 5	MOTOR FAILED
3	381	29 9	14 00	4 27	BS 2 5	MOTOR FAILED
4	324	29 5	1 50	4 19	BS 2 5	MOTOR FAILED
5	200	28 6	0 00	7 34	BS 3 0	PULLED TO CHANGE BHA
6	46	4 8	3 50	6 25	BS 2 5	TIME DRILL TO SIDETRACK
7	136	30 2	0 00	1 19	BS 2 5	PULLED TO CHANGE BHA
7	245	24 5	0 00	5 57	BS 3 0	PULLED TO PLUG BACK
8	272	18 8	5 00	6 84	BH 2 0 BS 1 5	MOTOR FAILED
9	193	21 4	10 00	3 95	BH 2 0 BS 1 5	MOTOR FAILED
10	135	15 0	3 00	10 48	BH 1 8	MOTOR FAILED
11	46	23 0	0 00	8 89	BH 1 8	FINISHED BUILD
AVERAGE PER RUN	176	22 6	2 71			
AVERAGE PER MOTOR	224	22 6	3 45			

Table 2
Downhole Motor Life

	Motor Runs				
Formula	**(1-4)**	**(5)**	**(6)**	**(7-8)**	**(9-14)**
Foamer	X	X	X	X	X
Polymer	X	X	X	X	X
KCL	X	X	X	X	
Graphite	X	X	X		
MF-1	X	X			
Soda Ash	X				
Drilling Hours	5	13	11	8	8
Hours to Restart	.5	14	1.5	3.5	6

Table 3
Coring Summary

Interval	Feet Recovered	% Recovery	No. Fractures Per Core Interval	Average Orientation
4043'-4056'	13' CORE 17' CUTTINGS	43% CORE 57% CUTTINGS	1	N37°E
4056'-4086	30' CORE	100%	5	N38°E ± 1°
4126'-4156'	30' CORE	100%	13	8-N39°E ± 1° 5-N29°E ± 7°

Table 4
Drag Coefficients

Measured Depth	Rotating Coefficient	Lowering Coefficient	Hoisting Coefficient
2595	Motor	0.45	0.60
3309	Motor	0.30	0.30
3803	8-5/8'' CSG	0.50	0.50
3509	0.30	0.40	0.60
3827	Motor	0.15	0.35
3987	Motor	0.10	0.20
4412	0.35	0.10	0.45
4854	0.35	0.25	0.50
5077	0.40	0.25	0.40
5509	0.35	0.55	0.50
5603	0.35	0.55	0.50
6020	0.35	0.60	0.45
6020	4.5'' CSG	0.15	0.15

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Table 5
Casing Program Installation of 6011 Feet of 10.5 lb, K-55, 4½'' Casing

Isolated Intervals	Number of Port Openings
3736-4095	8
4095-4194	4
4194-4337	4
4337-4811*	8
4811*-4986	4
4986-5176	8
5176-5411	8
5411-5602	8
5602-6011	4
*Special Inflatable Completion Packer	56

Table 6
Devonian Shale Horizontal Well Costs

	Third Party Costs	R&D Costs	Project Management
Site Selection, Reclamation, Well Design, Site Acquisition & Preparation		$280,082	
Drilling (Including Directional Driller)	$700,572		
Coring and Analysis		$ 54,758	
Logging	$ 41.248		
Well Testing and Analysis	$ 21,950		
Contingency (Plug Back #1 & #2)	$102,147		
Well Site Management (Drilling, Coring, Logging, & Well Testing)			$116,143
Subtotals	$865,917	$334,840	$116,143
Total Well Costs (Excluding Stimulation)			$1,316,900.00

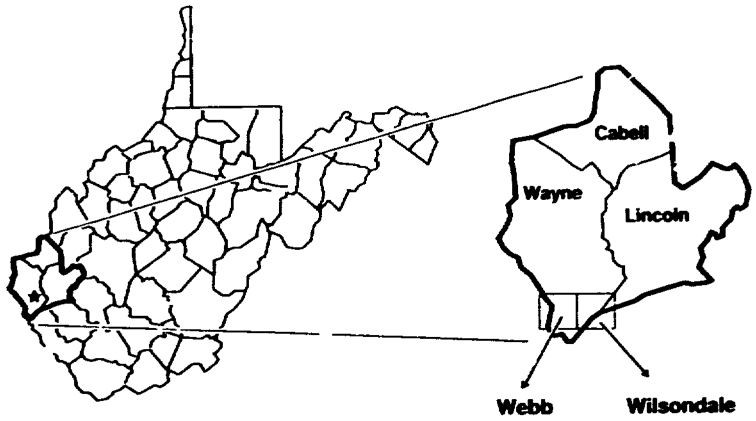

Fig. 1—Project study area, Wilsondale Pool, Wayne County, WV

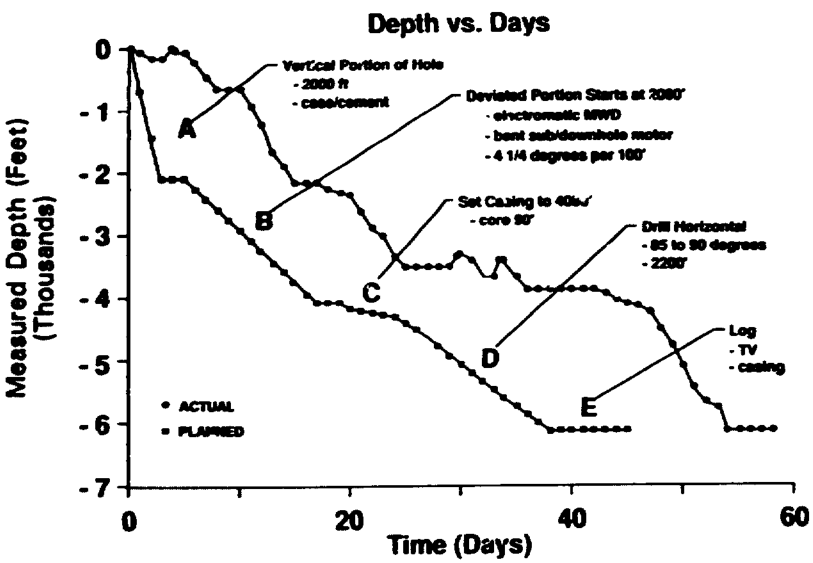

Fig. 2—Devonian shale horizontal well drilling schedule.

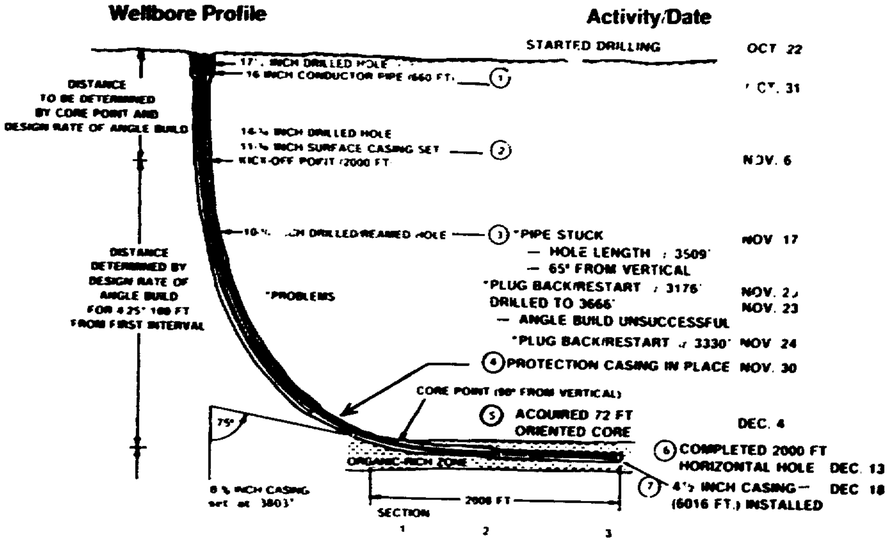

Fig. 3—Wellbore installation vs. activity

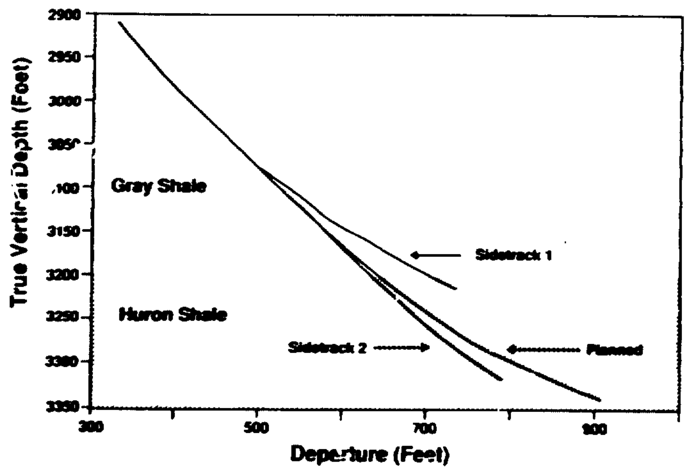

Fig. 4—Vertical view of sidetracks in horizontal well

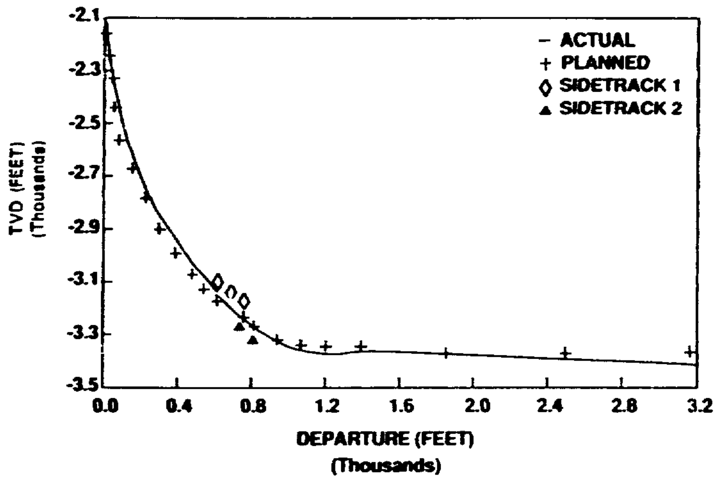

Fig. 5—Wellbore plot (actual vs. planned)

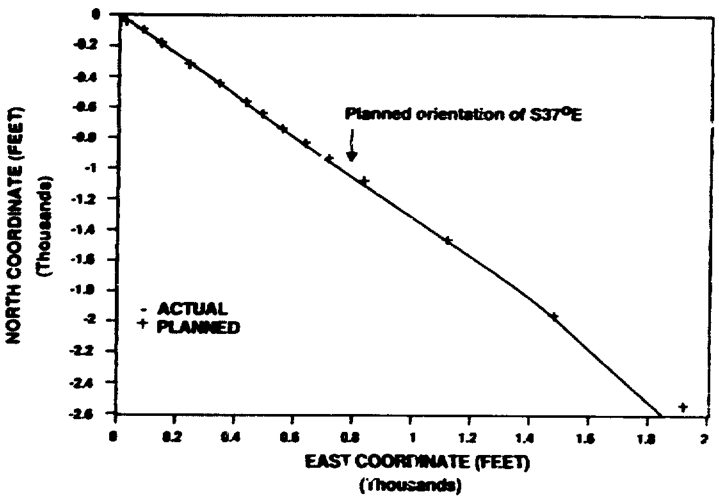

Fig. 6—Plan view of horizontal well.

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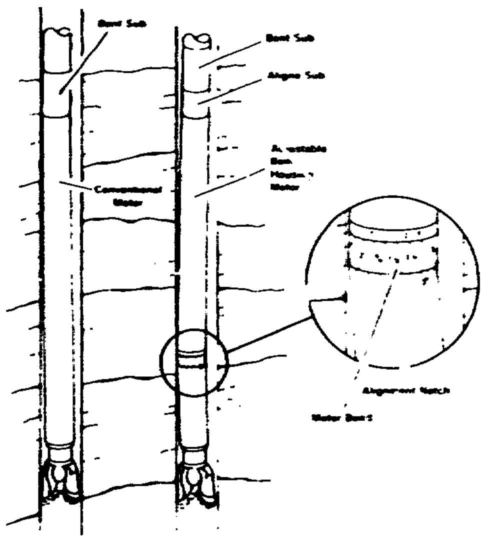

Fig. 7—Conventional/bent housing downhole motors

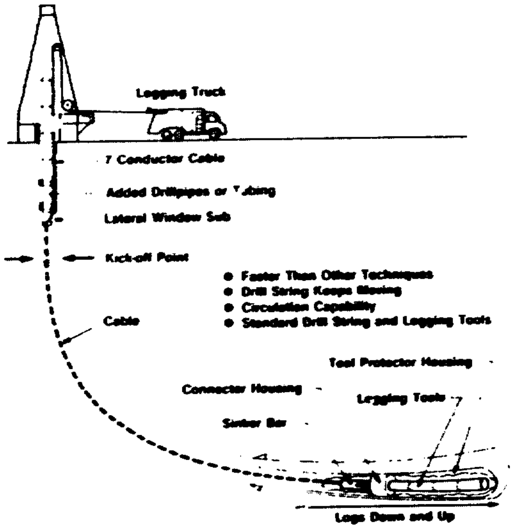

Fig. 8—Horizontal well logging system.

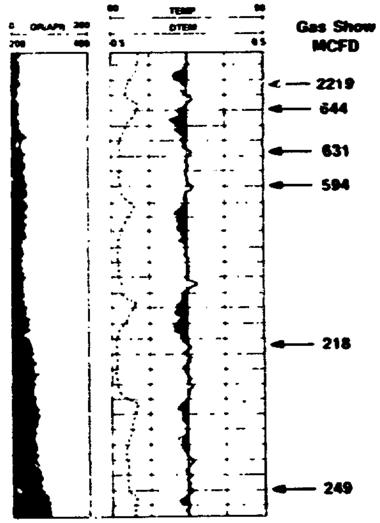

Fig. 9—Geophysical/mud log shows in horizontal section

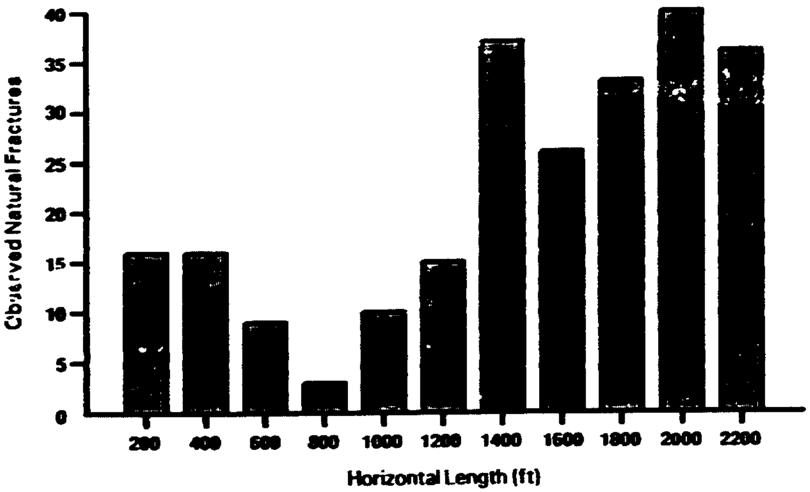

Fig. 10—Observed natural fractures from downhole camera.

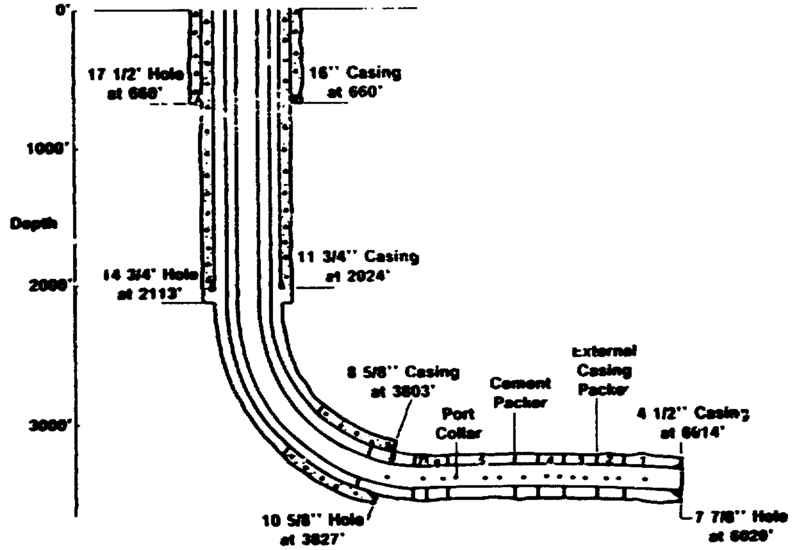

Fig. 11—Final wellbore schematic with casing installed.