SPE 54497

Successful Underbalanced Drilling by Pumping Nitrogen Through Coiled Tubing and a Vane Motor in the Low Pressured Pettit Lime Formation

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This paper was prepared for presentation at the 1999 SPE/ICoTA Coiled Tubing Roundtable held in Houston, Texas, 25–26 May 1999.

Abstract

Drilling productive reservoirs in near-depleted conditions is becoming more common. This operation is usually difficult and troublesome. This paper describes a successful field case history whereby casing was set on top of a depleted zone and nitrogen, coiled tubing, and a vane motor were used to drill underbalanced through the pay zone.

The reservoir had a bottomhole pressure of 150- to 200 psi at 5,000 ft. The reservoir would not withstand a column of foam for circulation, and also water-based drilling fluids and foam would cause formation damage. The decision was made to drill the section with coiled tubing and nitrogen. This type of operation required the use of a downhole motor that would allow the use of a compressed gas as the power medium. The operation was successful.

This paper will discuss the following issues related to this operation: (1) existing field conditions, (2) objectives, (3) options considered, (4) modeling parameters, (5) equipment design parameters, (6) bit selection, (7) operations planning, (8) actual operations, (9) cost analysis, and (10) recommendations for future improvements.

Introduction

This paper is a field case history of a unique drillout operation in a new well. The objective of the project was to recover gas from the low pressured Pettit Lime formation.

The method used was to drill conventionally and set casing on top of the pay zone, and then drill underbalanced through the pay zone without liquids to prevent formation damage. R. A. Hook, L.W. Cooper, and B. R. Payne site that an advantage of air drilling is imparting minimum damage to liquid sensitive pay zones.[1] The Pettit Lime formation is 200 ft in thickness at a depth of 4,900- to 5,100 ft. This reservoir is a part of the Sligo Field, Bossier Parish, Louisiana. Cumulative gas recovery for the Pettit Lime in this field is in excess of 100 billion cubic feet. The estimated bottomhole pressure (BHP) ranges from 150- to 200 psi. Air drilling techniques are used mostly in the drilling of offset wells where the geology is well known and the potential producing formations are of rather low pressure.[2] After the coiled tubing drilling operation was finished, the well was completed by hanging off the coiled tubing workstring to serve as the production string.

Existing Field Conditions

The well was located on Bureau of Land Management land inside of Barksdale Air Force Base Reservation, Bossier Parish, Louisiana. It was a large location that provided adequate room for the equipment.

Objectives

The first objective after setting casing was to drill out the float equipment and four feet of formation with fluid, positive displacement motor (PDM), and a 3.80 in. junk mill. The second was to blow the hole dry with nitrogen. The third objective was to drill out two hundred feet of the Pettit Lime formation with no fluid. The last objective was to complete the well live by hanging off the 2 in. coiled tubing as a packerless completion.

Options Considered

Air drilling rigs and equipment were unavailable in the area. During the initial planning session, a determination was made to drill the hole with coiled tubing and a PDM. PDM motors were readily available, but required some fluid or foam in order to function. However, the low BHP would not allow the use of foam. The fluid placed on the formation as a result would cause some damage. After further research, 2 in. coiled tubing and a vane motor were presented as an alternative that would run on straight nitrogen and perform for an extended duration with adequate torque output.

Modeling Parameters

Various models and equations were used in the planning stages of the operation. The modeling parameters chosen were used to determine the appropriate drilling fluid, the wellbore cleaning efficiency, and the appropriate tubular.

To check for the realistic use of a foam, it was found that the foam would have to be equivalent to a 0.75 lbm/gal fluid. However, the hydrostatic component of an 80 quality average foam is approximately 1.67 lbm/gal. When the friction component and required back pressure is included it is obvious that attempting a foam job would have overburden the sensitive formation. Thus, nitrogen was chosen due to its availability and favorable properties.

Since nitrogen was chosen as the drilling fluid, the flow rates were modeled. R.R. Angel's calculations on air drilling recommend 3,000 ft/min minimum annular velocity to lift cuttings and clean the wellbore.[3] The minimum required rate to maintain at least 3,000 ft/min in the wellbore was 700 scf/min as dictated by nodal analysis and using the conservative Beggs and Brill correlation.[4] A case can be made for using another correlation, but at the time Beggs and Brill was chosen because results would be conservative in nature. Rates were also modeled on location to give feedback. The vane motor required 3,000- to 5,000 scf/min nitrogen in order to achieve an adequate pressure differential. The nitrogen rate required for motor operation was four to seven times the minimum required rate to effectively clean the wellbore. Even though the velocities at the surface greatly differ when comparing the 700 scf/min and the 5,000 scf/min rates, the velocities at the bottom of the well essentially remained the same due to the compressibility of the nitrogen as seen in **Fig. 1**. This phenomena varies from conventional incompressible fluid flow where the increase in velocity is proportional to the increase in rate.

Since the intent was to use the workstring as the eventual production string, the 2 in. coiled tubing was chosen as the optimum size based on expected gas production and liquid unloading. The next step was to insure the coiled tubing properties along with appropriate safety factors were adequate to resist the forces and stresses that were to be induced during the drillout.

(1) Torque - The estimated torque output on the motor was 250 ft-lbf and the 2 in., 0.156 in. wall, 70,000 psi yield coiled tubing published torsional yield was 2,105 ft-lbf. The torsional working limits were 12% of yield.

(2) Overpull - The published minimum yield load was 63,300 lbf. The dry air weight of 5,100 ft of coiled tubing was 15,700 lbf and the estimated bottomhole assembly (BHA) weight was 1,000 lbf. At a maximum working limit of 80%, the estimated overpull was in excess of 33,000 lbf. The tensile working limits were 27% of yield.

(3) Weight on Bit (WOB) - A model predicted 8,000 lbf allowable WOB before lock-up would occur. The estimated maximum allowable WOB from the motor was 4,100 lbf. The WOB working limits were 51% of the coiled tubing limits.

(4) Cycle Life - For this one well operation, the pressure-cycle life was not a major concern.

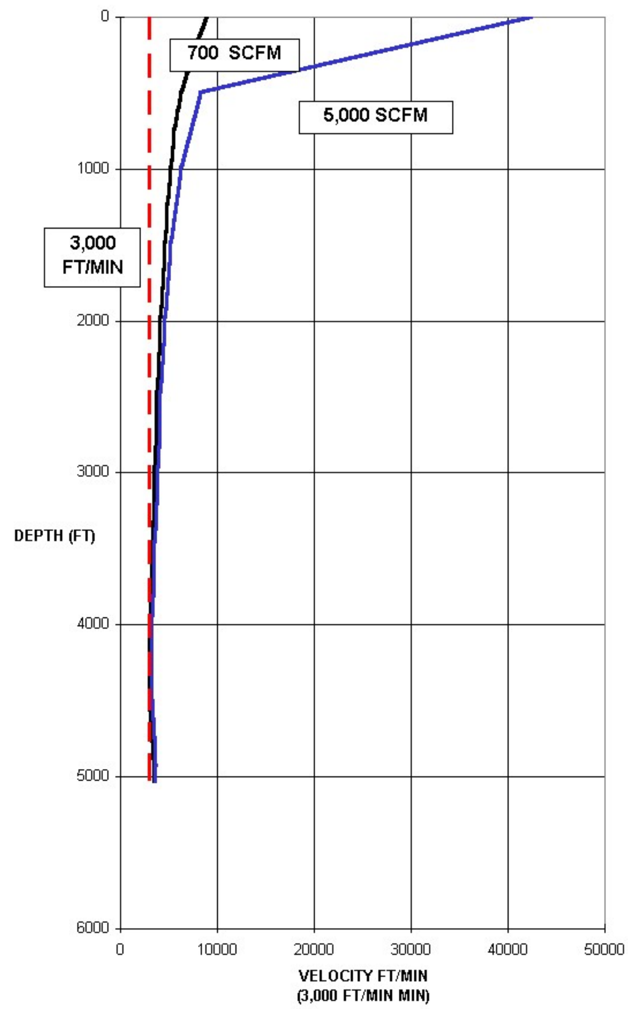

Fig. 1—Flowing velocity vs. depth using Beggs and Brill correlation.

Equipment Design Parameters

The general equipment design parameters for the pay zone drillout follow. The bit selection is separate.

(1) The 2 in., 0.156 in. wall, 70 grade coiled tubing – The coiled tubing had adequate overpull at 5,100 ft, adequate cycles at particular working pressures for this application, and large enough bore to flow through as the production string.

(2) Coiled Tubing Connector – The connector was a standard 2.875 in. outer diameter (OD) external slip-type to connect from 2 in. coiled tubing to the BHA.

(3) Dual Back Pressure Valve (BPV) – The BPV was a 2.875 in. OD flapper-type. It was a standard well control device.

(4) Hydraulic Disconnect – The disconnect has a 2.875 in. OD. It was standard BHA equipment used in coiled tubing operations.

(5) Drill Collars – The drill collar was a 2.875 in. OD pony sub and was supplied in 5 ft and 10 ft lengths. The drill collars were used for added WOB.

(6) Stabilizer – The stabilizer was three bladed with a 3.75 in. OD. The stabilizer was used to keep the hole straight since coiled tubing has a natural bend that tends to cause the BHA to drift.

(7) PDM - The 3.5 in. OD motor was used during the drillout of the float equipment using straight fluid. A circulating sub was used to blow hole dry with nitrogen.

(8) Two stage vane motor – The motor had a 3.125 in. OD. The motor would develop 250 ft-lbf and 850 rev/min when subjected to 1,200 psi pressure differential. It was a slimhole motor on the market that would drill for extended periods with 100% nitrogen and was available.

(9) Surface equipment - The main items were 6 in. blooie line, flow monitoring and choke equipment, and 4 1/16 in.-5M BOP stack.

(10) Tall Crane - The commercial crane was used to support the coiled tubing injector head, spacer spools, and the well control stack.

Bit Selection

A 3.80 in. OD 5 bladed junk mill was used to drill out the float equipment and first four feet of formation.

At the onset, there was a need to determine which type slimhole bit would perform the best for this well. Six main criteria were considered. First, the Pettit Lime formation was a soft formation. Second, nitrogen was the circulating medium to be used to clean the bit and the wellbore. Third, the high revolutions per minute induced by the vane motor had to be considered. Fourth, the 2 in. coiled tubing, and the short and relatively light BHA would limit the WOB. Fifth, the size of the bit was determined by the existing production casing. The bits were to have a 3.75 in. OD. Sixth, the bits used had to be immediately available.

A 3.75 in. OD natural diamond bit was chosen first because it was best suited for the 850 rev/min output of the vane motor, and was readily available. A 3.75 in. OD tri-cone mill tooth bit was chosen as a backup as it had been previously and successfully used in the Sligo field. A 3.75 in. OD polycrystalline diamond cutter (PDC) bit was located as a third option.

Operations Planning

A pre-spud meeting was held to make sure all participants understood and agreed on the operational procedures. The BHA configurations are listed below. The proposed wellbore schematic is shown in **Fig. 2**.

BHA No. 1. The BHA consisted of a coiled tubing connector, a dual BPV, a hydraulic disconnect, a 5 ft drill collar, a stabilizer, a 10 ft drill collar, a PDM, and a junk mill.

BHA No. 2. The BHA consisted of a coiled tubing connector, a dual BPV, a hydraulic disconnect, a 5 ft drill collar, a stabilizer, a 10 ft drill collar, a vane motor, and a natural diamond bit.

BHA No. 3. The BHA consisted of a coiled tubing connector, a dual BPV, a hydraulic disconnect, a 5 ft drill collar, a 10 ft drill collar, a vane motor, and a tri-cone bit.

BHA No. 4. The BHA consisted of a coiled tubing connector, a dual BPV, a hydraulic disconnect, a 5 ft drill collar, a stabilizer, a 10 ft drill collar, a vane motor, and a PDC bit.

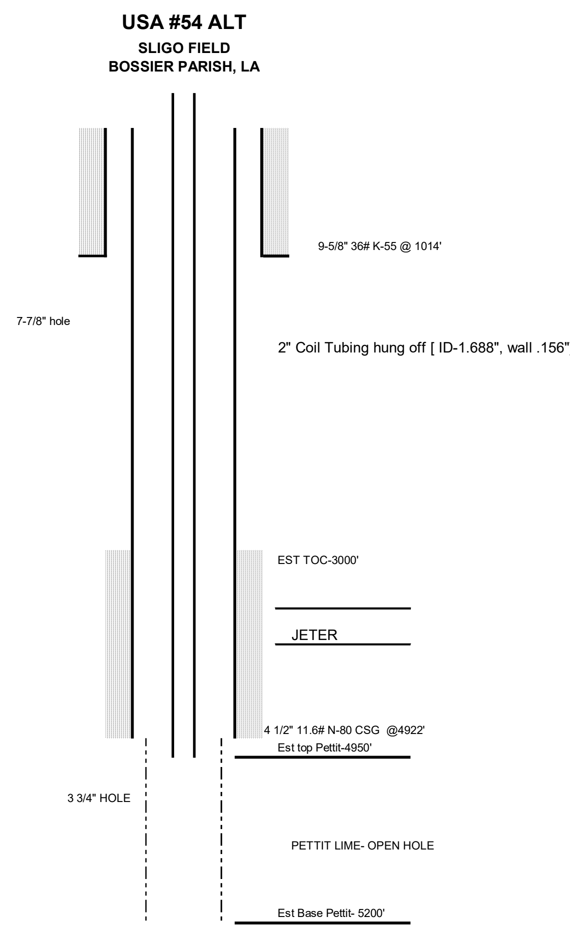

Fig. 2—Proposed wellbore schematic

Actual Operations

The drillout and hangoff took four days to complete. The operation summary follows.

Day 1. All equipment was moved in and rigged up including the coiled tubing unit, nitrogen and fluid pumps, and crane and flow monitoring station. The BHA No. 1 was made up and run in the hole. The equipment was pressure tested. The float equipment was drilled out with water. After drilling 4 ft of formation, the mill quit drilling due to balling up. The hole was blown dry. After tripping out of the hole to change out the bit and inspect BHA No. 1, the well was shut in for the night.

Day 2. The blooie line was enlarged from 2 in. to 6 in. and a 4 in. flow cross was installed to reduce the back pressure on the system.

Trip 1. BHA No. 2 using a natural diamond bit was made up and run in the hole. Nitrogen was pumped at 1,000 to

3,200 scf/min while attempting to drill, but only two to three feet were made in one hour with good circulation throughout.

Trip 2. A trip was made to change out to a tri-cone bit. The BHA No. 3 included a tri-cone bit minus the stabilizer was run in the hole and drilling was attempted with 2,000 to 3,400 scf/min of nitrogen and adding 0.25 bbl/min of 2% KCl water intermittently every 10 minutes. Pump pressures ranged from 1,200 to 3,400 psi. Various WOB were attempted, but drilling was sporadic and the bit was not drilling. The total footage with the tri-cone mill tooth bit was 15 ft. At one point, the penetration rate picked up to 7 ft in 30 minutes. The thought was that the motor may not have been turning properly, and therefore; the nitrogen was cut off and drilling continued with water only at a rate of 2 bbl/min as the pay zone had not been encountered yet. Three feet of hole was made, but drilling was stopped due to the proximity of the top of the Pettit. After jetting the hole dry and pulling out of the hole, there was no apparent damage to the bit even though it had been subjected to in over of 600 rev/min. Operations were suspended for the day.

Day 3. A PDC bit was made up and run in the hole on BHA No. 4 while circulating 3,000 scf/min at 1,200 psi. Fill was tagged nine feet higher than reached the day before. The nitrogen rate while drilling was staged from 3,500 scf/min through 5,000 scf/min in 500 scf/min increments. The pump pressures fluctuated from 1,700 psi to 3,200 psi. Drilling commenced smoothly with good returns until reaching a total depth of 5,105 ft coiled tubing measurement. With drilling complete, the well was circulated clean and the coiled tubing was pulled out of the hole. BHA No. 4 obtained a 180 ft/hr maximum instantaneous penetration rate and 56 ft/hr average penetration rate. The average penetration rate was based on drilling a 184 ft interval in 3 hours and 17 minutes. **Fig. 3** shows the penetration rate, average penetration rate, nitrogen rate, and the nitrogen pump pressure plotted next to the log for depth correlation. No obvious correlation could be made between the penetration rate and lithology from the log. No correlation could be made from nitrogen rate and penetration rate. Nor could anything be determined from pump pressure and penetration rate. The pump pressure fluctuations are most likely due to the pressure differential build up in the motor.

Day 4. The drilling equipment was rigged down and the coiled tubing hanger and standard hangoff equipment was rigged up. A normal 2 in. coiled tubing live well hangoff commenced. The coiled tubing was landed just above the top of the Pettit Lime formation and 7 ft below existing 4 1/2 in. casing at 4,930 ft. The new well was completed as a packerless completion. The initial test was 450 Mscf/D and 0.5 bbl/D of water.

Cost Analysis

The drillout was economical and with modifications the cost of a similar well can be reduced by an estimated $125,000. The new well was completed for $400,000 and a potential for 450 Mscf/D. It has leveled off at 350 Mscf/D and has continued to do so for 1.5 years. With improved bit selection, equipment reduction, and reduced time on location, the cost can be reduced to approximately $275,000 for future wells.

Recommendations for Future Improvements

The operation for this pilot well was a success. But, even with prior planing and vast experience, modifications need to be implemented to continue the evolution of the process. Some recommendations follow.

(1) Since hole cleaning requirements of nitrogen for this well configuration were substantially lower than required by the motor, the nitrogen usage could be lowered by using a 3:1 gear reducer on the motor. The gear reducer will reduce rev/min and increase the torque output by the same ratio. Therefore, it is possible to reduce the nitrogen rate to 33% of the original while meeting minimum hole cleaning requirements and still getting enough torque to the bit.

(2) Using a PDC bit with smaller nozzles will increase back pressure at the motor so as to increase the efficiency of the motor.

(3) For this formation and application, the PDC was the optimum bit. See **Table 1** for bit penetration rate comparison.

(4) The drill collars can be removed to eliminate the need for a large rental crane and extra spools. This will further reduce costs. It was possible to get ample WOB by slacking off of the coiled tubing.

(5) Use a large blooie line to reduce the effects of back pressure induced on the system due to frictional flow.

(6) Some costs can be eliminated without sacrificing safety and well control by removing the flow monitoring and choke system due to low BHP.

TABLE 1—AVERAGE PENETRATION RATES FOR THE DIFFERENT TRIPS IN THE HOLE

Description	Average Penetration Rate (ft/hr)
BHA No. 1 - Junk mill/PDM (shoe)	33.5
BHA No. 2 - Diamond bit/vane motor	1.5
BHA No. 3 - Tri-cone bit/vane motor	6.3
BHA No. 4 - PDC bit/vane motor	56.0
Overall combined (240 ft in 7:35 hrs)	31.6

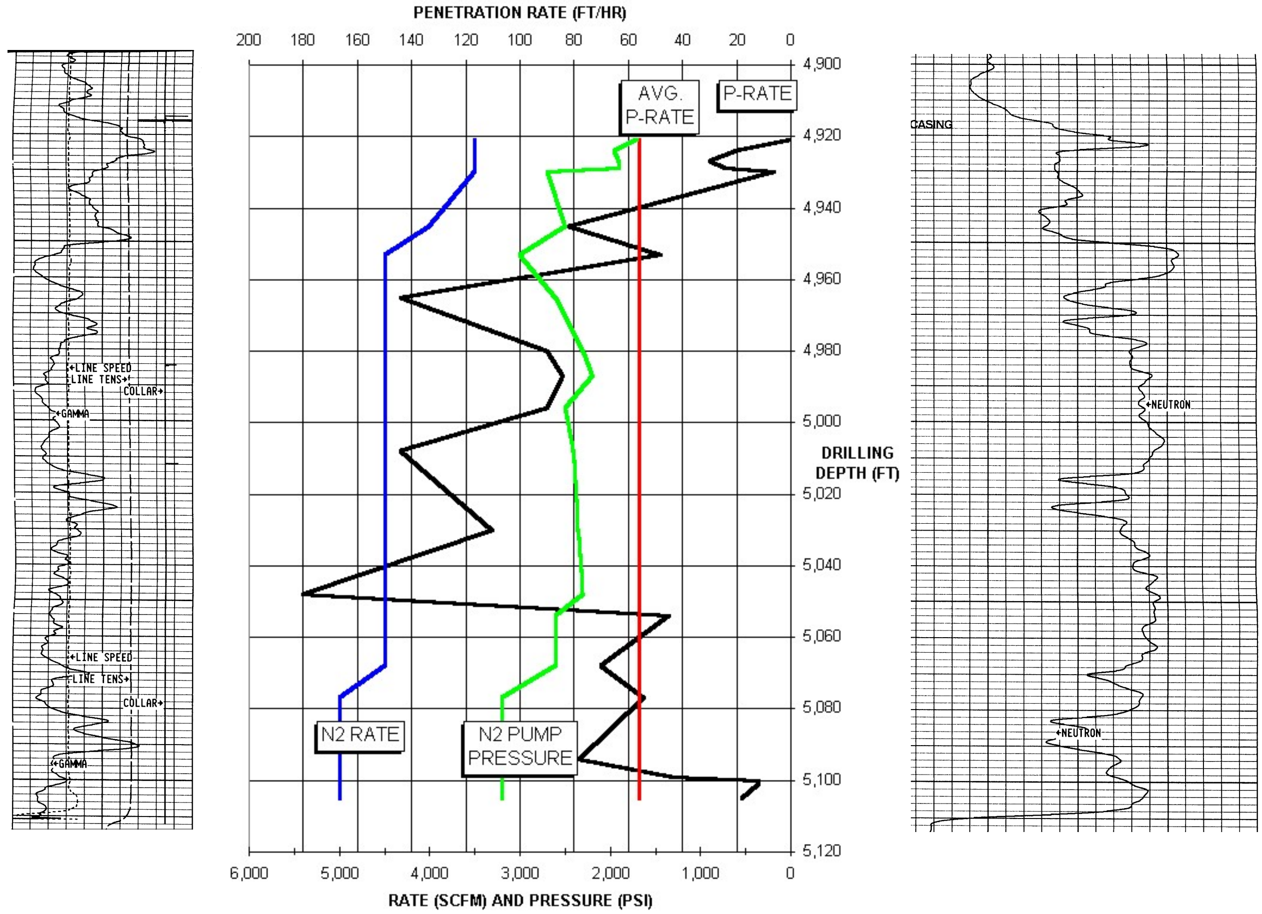

Fig. 3—Penetration rate, average penetration rate, nitrogen rate, and the nitrogen pump pressure plotted next to the log for depth correlation.

Acknowledgments

The authors would like to thank Seagull Energy E & P, Inc., and Cudd Pressure Control, Inc. for permission to publish this paper. We also thank the coiled tubing crew, Rotech Drilling Services, Ltd. and its representatives Dr. Hector Susman and Gary L. Harris, Baker Oil Tools, Sooner Testing, Schooner, and Wellhead Control Products, Inc. A thank you is extended to Steve Burrow who acted as the well control specialist. A special thanks is reserved for Mr. Buzz Sawyer, the on-site consultant, for his expertise and guidance on this project. He will be sorely missed.

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SI Metric Conversion Factors

bbl	x 1.589 873	E–01	= m3
cfs	x 2.83	E–02	= m3/s
cp	x 1.0*	E–03	= Pa. S
fps	x 3.048*	E–01	= m/s
ft	x 3.048*	E–01	= m
ft-lbf	x 1.356		= Nm
gal	x 3.785 412	E–03	= m3
in	x 25.4		= mm
ksi	x 6.894757	E+03	= kPa
lbf	x 4.448		= N
psi	x 6.894757	E+00	= kPa

*Conversion factor is exact

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