Horizontal air drilling increases gas recovery in depleted zone

Jeffrey P. Elrod *OXY USA Inc. Houston*

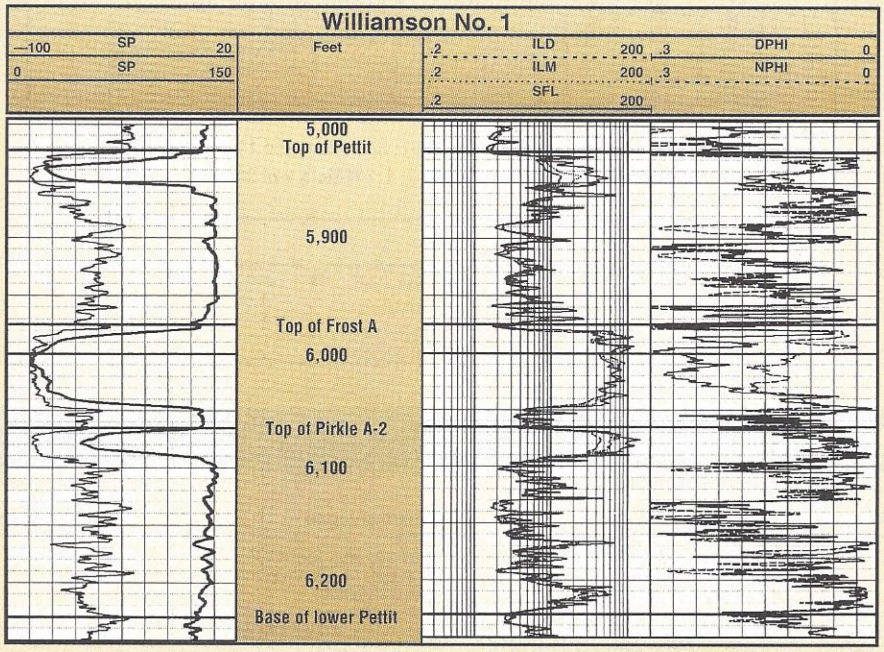
Increased gas recoveries in depleted gas zones can be achieved through horizontal air drilling.

In December 1995, OXY USA Inc. drilled the Pirkle 2, the first air-drilled horizontal well in the Carthage field of Texas. Targeting the Cretaceous Frost "A" zone of the lower Pettit limestone at 6,000 ft true vertical depth (Fig. 1), the well established production in a 1,400 ft lateral section with a bottom hole pressure (BHP) of 185 psi.

The initial BHP for the zone was 3,280 psi in 1942. As of Apr. 27, 1997, the Pirkle 2 had produced 530 MMcf of gas at a rate of 1.1 MMcfd (Fig. 2). Total cumulative gas production for the lower Pettit limestone in the Carthage field was 3.83 tcf as of January 1997.[1]

Fig. 1

PETTIT FORMATION, PIRKLE 2 OFFSET



Source: Reference 2

OGJ

Reservoir properties

The lower Pettit gas reservoir is one of seven producing formations in the Carthage field.

Positioned between 5,900 and 6,100 ft true vertical depth (TVD), the reservoir covers an area greater than 267,000 acres.

Classified as an ooid-coated bioclastic grainstone, the average porosity, water saturation, and permeability of the reservoir is 15%, 17%, and 35 md, respectively (Table 1).[2]

In-house, OXY has divided the lower Pettit into two main lobes, the Frost "A" in the area around the Pirkle 2, and the Pirkle A-2, which is located under most of OXY's acreage in the southwest portion of the field.

The Frost "A" section is a depletion-drive reservoir.

Table 1

RESERVOIR CHARACTERISTICS

	Average	Range
Pay thickness	15 ft	5-55 ft
Pay porosity	15%	7-30%
Permeability	35 md	0.6 to>1,000 md
Water saturation	17%	12-25%
Original pressure	3,280 psia	
Current pressure	200 psia	150-250 psia
Condensate yield	10 bbl/MMcf	8-20 bbl/MMcf

From Reference 2

Abandonment pressure

The current abandonment pressure for vertical wells in the Carthage area is estimated to be 110 psia. Incremental recovery calculations for horizontal wells indicate that production can be maintained at a bottom hole abandonment pressure of 58 psia, given the same economic surface flow rates of a vertical well.[2]

Substantiation for an economical horizontal well in the area requires production rates of at least twice that of an average vertical well.

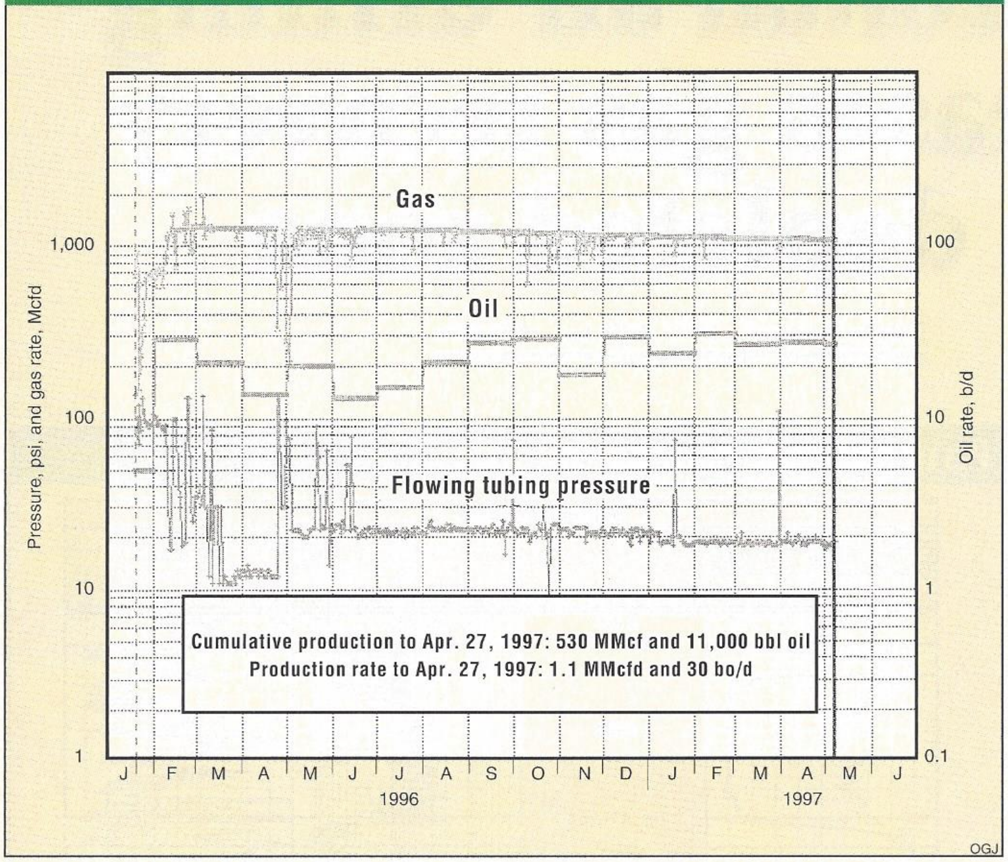
Minimizing well bore damage

The most important requirement in drilling the Pirkle 2 was to minimize well bore skin damage. Filtrate damage impedes a well's ability to flow back.

In low-pressure reservoirs

Fig. 2

PIRKLE 2 PRODUCTION RATES



OGJ

Table 2

DRILLING FLUID COMPARISON

Drilling fluid	Advantages	Disadvantages	Probability of causing damage
Mud	Least expensive, simple, able to log while drilling, no learning curve	Wall sticking, formation damage, filtrate invasion, lost circulation	High probability
Calcium carbonate	Thin, highly lubricious filter cake, minimal filtrate damage, flow back with minimal pressure, acid soluble	Expensive, no history with this magnitude of overbalance, relatively new on the market	Medium probability
Foam	Less damaging than mud, lighter hydrostatics than liquid systems, foam acid can remove damage	Expensive, fluid loss imminent, water block potential	Medium probability
Air	No liquid, minimal damage to formation, increased ROP	Expensive, no track record in area, unable to log while drilling, potential wellbore collapse, down hole fires	Least probability

like the Frost "A" zone, filtrate damage is extremely difficult to clean up, especially in horizontal sections. The extremely low reservoir pressure and the desire to minimize well bore damage created distinct drilling and completion challenges.

Primary drilling concerns included wall sticking, filtrate invasion, and formation damage. In order to overcome these problems, conventional and unconventional drilling methods were investigated.

Drilling fluid selection

Four fluid systems were considered for drilling the horizontal section:

1. Mud
2. Calcium carbonate
3. Foam
4. Air.

The advantages and disadvantages for each are shown in Table 2.

Because of the low reservoir pressure, it was important to reduce well bore damage by keeping liquids off of the reservoir and by minimizing filter cake buildup.

Cost analyses for the four drilling fluid types showed that mud is the least expensive and simplest system to use; however, it also causes the most formation damage. Cost comparisons for the other three options are similar.

In relation to formation damage, foam is the most damaging, followed closely by calcium carbonate. Air drilling is the least damaging of all.

These considerations led to the selection of air for drilling the horizontal section of the Pirkle 2.

Well bore configuration

The well bore configuration for the Pirkle 2 included drilling a 13½-in. hole with water-based mud to 1,985 ft measured depth (MD), and setting 10¾-in. surface casing (Fig. 3).

Then, a 9⅞-in. vertical hole was drilled with mud to the kick-off point (KOP) at 5,436 ft MD. Wireline open hole logs were run at this time for correlation purposes.

The 9⅞-in. curve section was also drilled with mud, using a measurement while drilling (MWD) and logging while drilling (LWD) directional assembly. Build rates were 10.34°/100 ft.

At an inclination of 84.25°, 7-in. casing was set through the curve and into the Frost "A" pay zone at 6,252 ft MD (5,984 ft TVD). The 6¼-in. horizontal section was drilled with air to protect the pay zone.

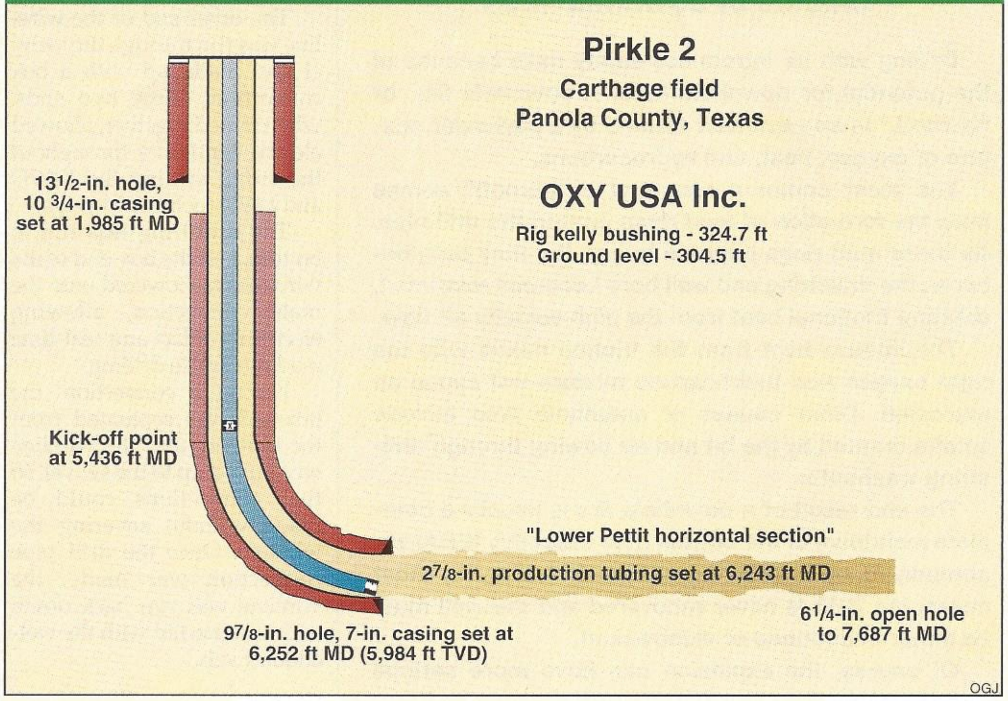
At a depth of 7,687 ft MD, the well reached the final total depth, and 2⅞-in. production tubing was set at 6,243 ft MD, 10 ft inside the 7-in. casing.

Special equipment, modifications

An air and nitrogen drilling operation requires rig modifications and special equipment not found in a conventional operation. Special equipment for the Pirkle 2 included air compressors, nitrogen membranes, air boosters, blow out preventors (BOPs), blooie line, and steering tools.

Fig. 3

WELL BORE CONFIGURATION



OGJ

Table 3

CURVE SECTION BIT SUMMARY

Bit No.	Make	Type	IADC code	Depth in, ft	Depth out, ft	Footage drilled	Hours on bit	ROP, ft/hr	Motor style
5	HTC	ATMMGT1	117	5,436	5,635	199	43	4.63	Mach 1P/HF
6	STC	S121STP	PDC	5,635	5,897	262	69	3.80	Mach 1P/HF
7	STC	F15	447	5,897	5,955	58	16	3.63	Mach 1
6 RR 2	STC	S121STP	PDC	5,955	5,998	43	22	1.96	Mach 1
8	RTC	HP51A	517	5,998	6,125	127	62	2.05	Mach 1
7 RR 2	STC	F15	447	6,125	6,252	127	49	2.60	Mach 1

Compressors

There were five, three-stage, positive-displacement air compressors on location (Fig. 4). Each had a maximum output capacity of 1,500 scfm and a maximum discharge pressure of 310 psig.

All five compressors were manifolded together and routed to a nitrogen-producing unit.

Nitrogen membrane

The nitrogen-producing unit (NPU) is a membrane-filter system that strips oxygen and moisture from the air and delivers nitrogen as the final product. The purity of the nitrogen gas ranges from 90.0 to 99.5%. In general, these units deliver approximately one half to two thirds of their input as usable output, depending on the purity required.

The membrane unit used to drill the Pirkle 2 was a 30-module unit capable of 3,000 scfm of output. Output from the five compressors was more than enough to maximize the output of the NPU.

The NPU's output pressure was less than the input pressure, requiring the gas stream to be boosted.

Air boosters

Boosters are used to increase compression, and in this case, to boost the NPU discharge pressures up to levels required for drilling. The boosters on location consisted of two, two-stage, trailer-mounted, positive-displacement compressors.

Throughput for each booster was 2,400 scfm. This increased the suction from 300 psig to 1,500 psig. The exiting line from the boosters was piped to the drill floor and plumbed into the standpipe.

There was a high-pressure/low-volume, mist-injection pump positioned downstream from the boosters. It is used to introduce mist or foam into the flow stream.

The line from the boosters was plumbed into the standpipe on the rig floor. Two bypass lines were run off this line to jets in the blooie line (air return line) prior to the standpipe. One of these, the primary jet, was piped to the end of the blooie line.

This line was used to create a vacuum on the annulus and draw flow away from the well bore to the flare pit.

The other line, the secondary jet, was piped to a point near the BOPs. This line acted as a blowdown line allowing pressure to be bled off the kelly and drillstring during connections (drill pipe additions).

BOPs

The BOP equipment for the Pirkle 2 was basically the same equipment normally found on a mud-drilled well.

However, the lowest set of rams in the stack was fitted with blind rams rather than pipe rams.

This allowed the well to be shut-in while the drillstring was out of the hole, allowing for the pipe rams to be safely changed.

In addition, a rotating head was flanged on top of the annular preventer (Fig. 5).

The rotating head was used to seal off flow between the well bore and drill floor, forcing it instead through a blooie line.

This can be done while the pipe is in motion or stationary. The pressure rating of a rotating head is much less than an annular preventer.

Blooie line

The blooie line is the discharge air-flow line which exits an outlet located in the rotating blow out preventor (RBOP). It runs to a flare pit and allows gas to move safely away from the rig (Fig. 6).

As mentioned previously, the blooie line had two jets, one near the RBOP and the other near the end of the blooie line. It was constructed of 8⅝-in. pipe.

The secondary jet was a 2-in. line connected to the blooie line at a 20° angle. It was located 5 ft from the rotating head. From the secondary jet, the blooie line dropped slightly to a point above the possum belly.

The sample catcher was placed in the line in-between the shakers and substructure (Fig. 6). It consisted of two nipples and two ball valves stacked so that the top valve could be opened with the bottom remaining closed.

In order to catch a sample,

the top valve was closed and the bottom valve opened. Downstream from the sample catcher, a "T" was installed above the shale shaker. One end of the "T" led into the possum belly, and the other line led to the flare pit.

The possum-belly line had a valve which was closed while air drilling. This diverted air down through the blooie line and into the flare pit.

A water injector was installed near the end of the blooie line just upstream of the primary jet (Fig. 6). Its purpose was to spray a small stream of water onto the dry cuttings in order to keep the dust down.

The water injection line (de-duster) consisted of a 1-in. pipe located at the top of the blooie line several feet in front of the primary jet. The primary jet was placed 5 ft from the end of the blooie line.

An electric-spark propane ignitor was placed at the very end of this line (Fig. 7). Unfortunately, when heavy volumes of fluid or extreme amounts of gas were expelled, wet cuttings from the well bore would coat the sparker and the flare had a tendency to go out.

Steering tools

The steering tools consisted of directional and gamma ray tools seated in the bottom hole assembly (BHA).

The wet-connect system provided the means to transmit data from the BHA to the surface for purposes of geosteering within the Pirkle "A" pay zone.

Conventional MWD methods would not work because they require a liquid medium for data transferal (pulse telemetry).

With the wet-connect system, the wireline remained inside the drill pipe, permitting multiple makes-and-breaks of the wireline connectors as well as allowing both rotary and slide drilling.

Slide drilling is used for the purpose of controlled directional steering. The string is not rotated.

The system consisted of:

- A special swivel
- Male and female connectors
- A wet-connect sub
- Wireline tools and wireline.

The specially designed swivel hung from the blocks. There was an hydraulic pack-off located in the top of the swivel so the drillstring could rotate while keeping the wireline steady.

This allowed the wireline to remain in the hole while drilling.

The pack-off could be tightened or loosened remotely from the wireline truck in order to hold pressure on the wireline or move it up or down. This type of system saved valuable time while drilling the lateral section.

The wet-connect sub was placed so that it would remain in the vertical part of the drillstring section during drilling. The pin-end was installed on the wireline and set within the wet-connect seating sub.

The other end of the wireline was run through the swivel and made up with a box connection. These two ends, when mated together, allowed electric continuity throughout the string so that the MWD and LWD tools could work.

The drillstring was run to bottom, and the box-end of the wireline was lowered onto the male connection, allowing electrical contact and real-time readings while drilling.

During a connection, the box-end was separated from the pin-end, and the wireline was pulled up to the swivel, so that connections could be made without severing the wireline. Once the drill pipe connection was made, the wireline was run back down and reconnected with the wet-connect sub.

Drilling

The well spudded on Dec. 1, 1995. A 13½-in. hole was drilled to 1,985 ft where 10¾-in. casing was set. Surface casing was drilled out with a 9⅞-in. bit.

Mud weights were increased to 10.2 ppg early in the hole section to prepare for the Goodland Lime and Duck Lake injection zones at approximately 2,600 ft.

Mud weights were increased to a maximum of 10.8 ppg through these sections, but were reduced to 10.2 ppg by 5,000 ft. At 5,160 ft, an 11.4 ppg mud weight was needed to drill through the Rodessa water injection zone.

The well was logged with a wireline dual induction laterolog and gamma ray tool at 5,436 ft (the kick off point). While tripping in after logging, the well took a salt-water kick and required 11.8 ppg mud to contain it.

Because of problems in reconditioning the mud after the salt water kick, the mud weight was kept between 11.6 and 11.8 ppg while drilling the build curve.

Curve section

The Pirkle 2 required 15

Nitrogen gas drilling reduces chance of downhole fires

Drilling with air introduces safety risks because of the potential for downhole fires. A downhole fire, or "burnoff," is an explosion caused by a particular mixture of oxygen, heat, and hydrocarbons.

The most common cause of a "burnoff" comes from the formation of mud rings around the drill pipe. As these mud rings become larger, the flow path between the drillstring and well bore becomes restricted, creating frictional heat from the high velocity air flow.

The intense heat from the friction mixed with the right oxygen and hydrocarbon mixture will cause an explosion. Other causes of downhole fires include sparks created by the bit and air flowing through drillstring washouts.

The end result of a downhole fire is usually a complete meltdown of the bottom hole assembly (BHA) accompanied by a severing of the drillstring. In most cases, the BHA is never recovered and the well must be either abandoned or sidetracked.

Of course, the explosion can have more serious consequences.

There are two methods that can greatly reduce the hazard of downhole fires:

Adding water to the air, or misting (96% to 99% air).

Using nitrogen, an inert gas, in place of air.

Drilling with "mist" decreases penetration rates, but there can be substantial advantages and cost savings. Using vaporized-liquid nitrogen as a source is not cost-effective, but using nitrogen generated from a membrane unit is. This allows the well to be dry-drilled, often called "dusting."

Not only does nitrogen virtually eliminate downhole fires, it makes tripping and adding drill pipe safer because of the inert nature of nitrogen.

Added benefits of nitrogen injection over misting include faster penetration rates and reduced volumetric air requirements (as great as 30%).

The use of a nitrogen membrane unit was the safest and most economical method for the Pirkle 2.

Each one of the five, three-stage, positive-displacement air boosters on the Pirkle 2 location was capable of 1,500 scfm of output capacity (Fig. 4).

days to drill the 850 ft of angle build section, rather than the planned 5 days.

A total of four bits (six bit runs) were needed, averaging 3.1 ft/hr (Table 3). The average build rate was 10.34°/100 ft.

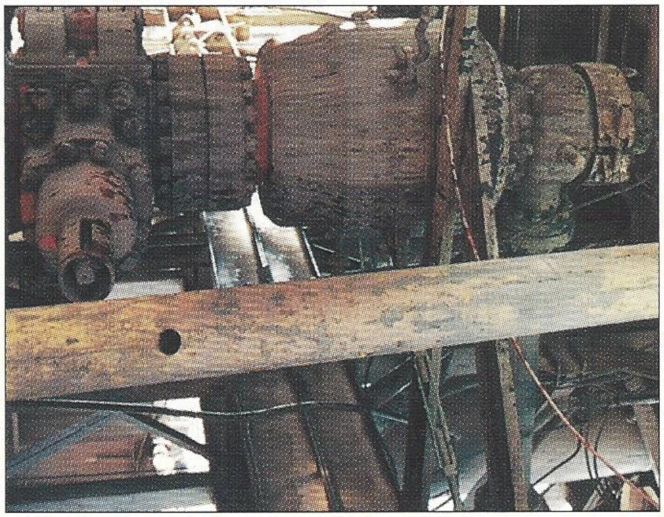
In an attempt to increase the rate of penetration (ROP), bit types and motor styles were varied. Bits used in this section included one tooth bit, two button bits, and a polycrystalline diamond compact (PDC) bit.

Unfortunately, average penetration rates did not change substantially, regardless of the configuration.

The initial downhole motor was a 9:10 rotor/stator combination capable of speeds between 100 and 180 rpm with flow rates in the range of 345-610 gpm.

This motor was used until 5,897 ft MD when a 5:6 rotor/stator combination capable of 100-260 rpm using flow rates between 185 and 475 gpm motor was picked up.

The change in motors allowed for higher rotational speeds for similar flow rates, averaging 400 gpm. Again, there were no noticeable differences in penetration rates. The lack of drilling improvement was attributed to slide drilling and high mud weights.



In typical air drilling operations, the blooie line is flanged to a rotating head situated on an annular preventor and a two-ram BOP (Fig. 5).

At 5,870 ft MD (5,828 ft TVD), a 4 ft drilling break was encountered at the top of the upper Pettit A-2 zone. The BHP at this time was 280 psi. Then the well began losing mud for a total loss of 200 bbl.

A lost circulation material (LCM) pill was pumped, and drilling continued. Some hole drag and sticking tendencies were noticed until the motor and collars passed through this zone.

Because of the desire to penetrate as little of the objective zone as possible before setting intermediate casing, the build section was terminated at 6,252 ft MD (5,984 ft TVD) at an inclination of 84.25°.

A string of 7-in., 23 lb, N-80 and K-55 casing was run in the hole from surface to TD. The well was cemented from the bottom with enough slurry to cover the Rodessa injection zone. A second slurry was pumped through a DV tool at 3,119 ft to cover the Goodland Lime and Duck Lake injection zones.

Air-drilled, horizontal section

Once the casing was cemented and the tubing head nippled up, the BOP stack was reset.

A Hydril 11-in., 5,000-psi, triple-ram BOP was bolted onto the tubing head, followed by a Hydril 11-in., 5,000-psi, dual-ram annular BOP, and a Williams 12-in., 3,000-psi rotating head (Fig. 5).

An 8⅝-in. blooie line was connected to the rotating head. A 4¼-in. kelly was picked up for use with 3½-in. drill pipe.

A string of 3½-in. drill pipe and 30 joints of 3½-in. heavy-weight drill pipe were used for drilling the 6¼-in. lateral hole.

The cement, float collar, shoe joint, and part of the float shoe were drilled out. The hole was circulated clean. Mud was displaced with water and the drillstring was pulled out of the hole. Final changes in the surface equipment were made.

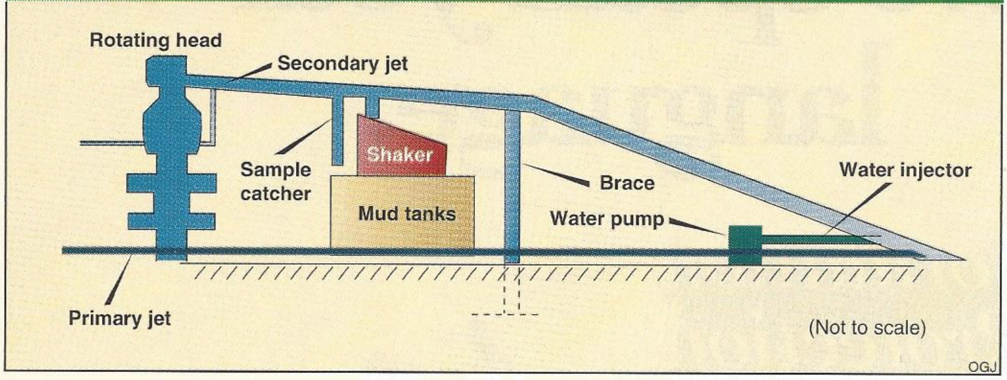
The drillstring was then staged back in the hole (intermittent stops) with displacement of water by air at 3,000 ft, 5,200 ft, and 6,252 ft. Once the water was blown out, 15 gal of foam was mixed and circulated around to dry out the hole.

The drillstring was tripped out and the air- drilling BHA was tripped in the hole.

- The air-drilling BHA consisted of:
- HTC ATJ-33A bit with no jets
- Mach 1/AD 1.2° adjustable kick-off motor
- Stabilizer
- Float sub
- Two nonmagnetic pony collars
- Cross-over and stabilizer
- Nonmagnetic drill collar
- 105 joints of S-135 drill pipe
- 30 joints of heavy weight

Fig. 6

BLOOIE LINE LAYOUT



An electric-spark propane ignitor was mounted on the end of the blooie line and was used to flare gas during shows and tests (Fig. 7).

drill pipe.

Drilling of the shoe was completed and dry drilling operations began.

The drilling rate peaked at an instantaneous rate of 318 ft/hr with an average penetration rate of 87 ft/hr.

The hole was drilled from 6,252 ft to 6,564 ft MD (302 ft) when the gamma ray tool failed.

The string was pulled up to the wet connect sub, the wireline pulled out, and the gamma ray tool was changed and run back in.

The string was tripped back in the hole and drilling continued to 6,877 ft MD when the rotating head rubber started leaking.

The drillstring was pulled into the 7-in. casing and the rotating rubber was changed out.

After tripping back to bottom, drilling continued to 7,002 ft MD where air returns were lost (no flow to the surface). Attempts to regain circulation using foam slugs were unsuccessful. It was assumed that circulation had been lost to the formation.

Because of the extreme low reservoir pressures involved (under 200 psi), the traditional indications of a mud ring including increased standpipe pressures, torque, and drag were unnoticed.

The air flow took the path of least resistance, down the drillstring and into the formation. The drill pipe was staged out with circulation attempts at 6,283 ft, 5,363 ft, and 3,936 ft.

At 5,363 ft MD, pressure was applied to the annulus in an attempt to push fluid back into the formation. This was unsuccessful. Because circulation was not regained, the drillstring was tripped all of the way out of the hole.

As the BHA got closer to the surface, the flare grew in size. During this time, nitrogen was bypassed through the primary jet to draw the gas away from the rig floor.

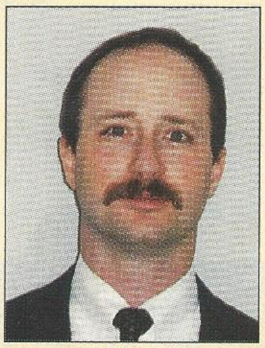
The well began blowing chunks of wet mud cake out of the blooie line. Within 750 ft of the surface, the same amount of open hole that had been drilled, the well began flowing at a fair rate and abundant wet mud cake was blown out of the blooie line.

Apparently, there was just enough formation fluid in the hole to inhibit cuttings removal. Information after the fact indicated that all five compressors were not operational when circulation was lost. One had been shut down which changed the flow regime, thereby reducing the injection rate.

It appeared that as long as all compressors were operating, annular flow rates were sufficient to obtain gas returns. However, velocities were not high enough to remove all of the cuttings and liquids.

This induced the cuttings to be wetter than normal, creating an environment where the cuttings were building up on the outside of the drill pipe.

THE AUTHOR



Elrod

Jeffrey Preston Elrod is a drilling engineer for OXY USA Inc. His responsibilities cover both onshore and offshore drilling operations in the southern U.S. and the Gulf of Mexico.

Elrod has been with OXY since 1988 and worked as a production and reservoir engineer before joining the drilling group in 1993. He received his BS in petroleum engineering in 1986 from the University of Tulsa, and an MBA in 1988. He is registered as a professional engineer in Texas.

Because of the low reservoir pressure, the air flowed into the formation without causing any noticeable back-pressure increase on the standpipe gauge.

At a depth of 7,002 ft MD, the bit and motor were tripped out and changed. Inspection of the BHA did not indicate substantial wear. Despite rerouting air flows through the primary jet, the drawdown in the rotating head was insufficient.

As a result, subsequent trips required the well to be killed with foam slugs to alleviate gas flowing up onto the rig floor. Before tripping back in, the primary jet was moved from the end of the blooie line to a point 45 ft from the rotating head in order to improve the jetting and suction action.

Reportedly, this provided good results in the West Texas area but results from the Pirkle 2 did not substantiate it. There was increased suction at the sample catcher, but no noticeable improvement at the end of the blooie line.

Reasons for this may be related to the extra back-pressure encountered from an extended blooie line and the additional moisture buildup from misting.

While out of the hole, unofficial flow tests were conducted. A 1 min shut-in yielded 150 psig, and a 10 min shut-in yielded 155 psig. The well was flared in order to lower and stabilize the casing pressure.

A deliverability test was performed by observing the flare and casing pressures, while flowing through the choke fully open, ¾ open, ½ open, and ¼ open. Estimates were in the range of 2.5-4.0 MMcfd.

Stiff foam was then pumped into the well bore to kill the well, and a new ATJ-33A bit and a motor were run in the hole. The bit was jetted with $3\frac{11}{32}$-in. nozzles.

While tripping in, the foam was displaced every 1,000 ft. As drilling resumed, misting was implemented in order to clean the hole for the remainder of the job.

The same penetration rates as the first bit was never achieved. This may have been due to misting the hole, jetting the bit, differences between the motors, and/or increased air drag because of the increasing length of the lateral.

Surface pressures climbed from 450 psi during the first BHA run, up to as high as 900 psi for subsequent BHA runs. The rise in surface pressures reduced air volumes through the motor.

In addition, after each connection the pressure climbed an additional 100-150 lb above normal drilling pressures.

The chemicals used while mist drilling were a foamer, corrosion-control agent, polymer, and water mixed and injected at 12 bbl/hr.

At 7,220 ft MD, the drilling assembly began building too much angle.

The motor appeared to be locked-up because there was no pressure increase while on-bottom, compared to off-bottom. In addition, the motor would not slide.

The well was killed with 30 bbl of stiff foam, then the BHA was tripped out of the hole and a new motor was run. The same bit was rerun.

Again, the well was killed with 30 bbl of stiff foam and the drillstring was staged back in the hole while blowing dry at 1,000 ft intervals. Once back on bottom, drilling continued in both slide and rotary modes to 7,258 ft MD.

After this last trip in the hole, it was determined that enough lateral hole had been made and drilling would discontinue at the end of the run.

At 7,625 ft, the hole began packing off and the drillstring was unable to slide. Air was

FOCUS: DRILLING

bypassed to the blooie line and the BHA unstuck itself. The drillstring was pulled up into the casing at 5,800 ft and foam pills were pumped to clean the hole.

The drillstring was staged back to 6,900 ft where foam pills were again circulated to clean the hole. Drilling resumed and was continued to a depth of 7,687 ft MD whereupon the well came to the final total depth (TD).

The wireline was retrieved and the drillstring pulled to the wet-connect sub. Once the steering tools were laid down, the pipe was tripped back to bottom for one final foam sweep to clean the well prior to laying down drill pipe.

Completion

To begin the completion phase, the pipe rams were changed from 3½ in. to 2⅞ in., and the rig was rigged-up to run 2⅞-in. tubing.

Tubing was run to 6,243 ft at an inclination of 82°. The tree was nippled up and the well prepared for production.

Production

A nodal analysis was performed to compare annular and tubing string flow rates in order to optimize production. The calculations showed that annular flow would yield higher rates than tubing flow.

However, field experience showed that although annular flow had higher rates, the well tended to load up and die after a few days. Continuous flow could only be obtained by flowing up the tubing.

A low-pressure compressor was installed to boost the well pressure needed to enter the 110 psi gathering system.

After 97 days of production, the flowing BHP was 143 psig. The well was then shut-in for 3 days and the BHP built up to 152 psig, a drawdown of 9 psi between the reservoir and the well bore. The buildup test confirmed skin damage was minimal during drilling operations.

Future improvements

As is the case when implementing new procedures, the learning curve provides insights into practices and methods that can be used in future programs. The following provides a basis for improving horizontal air-drilling in the Carthage area.

Mist drill rather than dry drill. This will improve the removal of cuttings, cool the bit, and eliminate the need for the nitrogen membrane unit.

Keep the primary jet at the end of the blooie line in order to improve the jetting action.

Place a continuous-flame, flare-ignition system at the end of the blooie. This should be capable of staying lit under extreme conditions.

Place a meter and chart recorder on the rig floor to monitor standpipe pressure. This will provide historical pressure readings to supplement real-time data.

Do not jet the bit. This restricts flow through the motor.

Obtain an injector pump that can mix and pump stiff foam within a short amount of time.

Acknowledgments

The author would like to thank Robert A. Joseph, Alex W. McCoy, and David Giffin for their assistance in preparing this article.

References

1. Dwight's Energy Data, January 1997.
2. McCoy, A.W., et al., "Using Horizontal Well Technology for Enhanced Recovery in Very Mature, Depletion Drive Gas Reservoirs—Pirkle No.2 Well, A Case History, Carthage (Lower Pettit) Field, Panola County Texas," SPE paper 36751, presented at the 1996 SPE Annual Technical Conference and Exhibition, Denver, Oct. 6-9, 1996.