Multilateral Horizontal Well Increases Liquids Recovery in the Gulf of Thailand

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Summary

This paper describes the objectives, the completion, and the first results of the dual-horizontal Well BK-4-M, which was drilled in May 1996 in the Bongkot field. The main objective of Well BK-4-M was to maximize the recovery from a shallow and thin oil rim by delaying the water breakthrough by 2 years and by maintaining a flow rate of 4,000 B/D. Compared with a conventional deviated well, the final recovery will increase by three times. The completion of Well BK-4-M was a challenge in terms of technical and economic planning. Well BK-4-M was put on stream successfully in July 1996 with a potential flow rate of 4,000 B/D. The duration of operations was 21 days, including completion. Each of the two horizontal branches has a length of approximately 1000 m and is located in the upper third of the 10-m-thick oil rim. The cost of Well BK-4-M was 1.70 times higher than a conventional single-drain deviated well, and the well is expected to triple recovery by using only one platform slot. It is the first dual-horizontal well ever completed in Southeast Asia.

Introduction

Bongkot Field. The field is situated offshore in the Gulf of Thailand 600 km south of Bangkok and 180 km off the coast of Songkhla province (**Fig. 1**). After discovery of the field in 1973, it was delineated by the drilling of 23 wells.

In 1990 the concession development rights were transferred to a joint venture group comprising PTT E&P Public Company Ltd. (40%), Total E&P Thailand (30%; operator), British Gas Thailand Ltd. (20%), and Statoil Thailand Ltd. (10%).

Since the start of the development phase of the field, 114 wells have been drilled, of which two-thirds have been development wells and one-third have been delineation wells. The development wells were drilled from 12-slot wellhead platforms. A self-erecting tender barge[1] installed a rig package on the platforms for the duration of drilling and completion operations. Further well interventions were performed without the rig.

The production from the remote platforms was transported to a central processing platform for treatment. Gas was piped to shore, and liquids were stored on a floating storage and offshore loading facility. Liquids were exported by shuttle tanker.

By mid 1996, gas production from the field was 350 million scf/D, and condensate production was 8,000 B/D.

Geological Context. As currently delineated, the field extends over an area of 450 km^2, with a length of 70 km and a width of 5 to 12 km. Proven reserves were certified at 3 trillion scf in 1994. The water depth over the field varies between 75 and 80 m.

The hydrocarbon reserves exist in multifaulted sandstone reservoirs of the Oligocene and Miocene ages and are deposited in fluvio-deltaic and coastal environments.[2] These reservoirs are found over a large range of true vertical depths (TVD's), from 1000 to 3000 m below mean sea level. All reservoirs developed to date have had a hydrostatic pressure regime.

The majority of the hydrocarbon-bearing reservoirs contain gas and associated condensate. However, in certain reservoirs, significant oil rims have been identified underlying the gas column. Oil columns up to 15 m thick have been identified. Channels that will contain oil rims are difficult to predict, and drilling and logging are the only methods that will prove the presence of liquid hydrocarbon.

The largest oil accumulation identified to date is in a structure known as the 10-90 A (**Fig. 2**). This structure was the candidate reservoir for the horizontal Well BK-4-M.

A Reservoir Description of 10-90

Reservoir History. The anticlinal Structure 10-90 A was first identified by the interpretation of seismic data and was originally predicted to be a gas-bearing sand formation.

The first well to penetrate the reservoir was Exploration Well 15-B-2X. This well proved the existence of a reservoir 24 m thick that contained a column of gas 3 m thick, underlying which was 9 m of oil and 12 m of water-bearing sand. After the installation of the wellhead platform WP4 in the 10-90 A area, development drilling began in February 1995.

The first well drilled, Well BK-4-G, encountered the 10-90 A structure downdip of the exploration well. This well did not cross the gas cap, and it encountered 8 m of oil. A second well, Well BK-4-L, penetrated the structure further updip, encountering an oil column of 9 m that overlay a gas cap 9 m thick. A log of the 10-90 reservoir interval from Well BK-4-L is presented in **Fig. 3**.

Reservoir Geometry and Properties. Reservoir 10-90 is located at approximately 1070 m TVD at mean sea level. It consists of a series of amalgamated channel sands with considerable lateral extension. The 10-90 A structure has been mapped, revealing an anticline with a closure of 42 m. At the top of the structure, the fluid columns were estimated initially to contain 17 m of gas, 9 m of oil, and 16 m of water.

The sandstone that makes up the 10-90 reservoir is poorly consolidated. Porosity is approximately 29%, with an initial water saturation of 20%. In the oil zone, the horizontal permeability is approximately 2000 md and vertical permeability is approximately 100 md. The fluid is a light oil with 54° API gravity and a gas/oil ratio (GOR) of 570 scf/STB.

The initial reservoir pressure was calculated to be 104.5 bar at the gas/oil contact (GOC) at 1061 m TVD at mean sea level. Oil in place was estimated at 22.5 million STB, and free-gas reserves were estimated at 8.5 billion scf. A large and active aquifer underlies the oil reservoir. Delineation wells proved the lateral extent of this aquifer, and production data showed active pressure support. A negligible pressure drop was measured after 10 months of production from the reservoir.

Production Data. Wells BK-4-G and BK-4-L were perforated across multiple reservoirs, including the 10-90. Multizone completions were run, allowing selective production by use of wireline-operated sliding sleeves in each separate zone. This completion method allowed production from 10-90 reservoir to proceed as a separate zone in both wells. After the completion of these wells, drilling operations were suspended from the platform. The wells were put on stream and produced.[3,4]

Well BK-4-L, which was perforated in both the gas and oil zones, principally produced gas. Therefore, the 10-90 zone was shut in to preserve the gas cap.

Well BK-4-G was perforated in the oil zone in the 10-90 reservoir. Initially, the zone produced 1,500 B/D of dry oil (**Fig. 4**). However, after only 1 month of production, the well started to produce water. Within 4 months, the water cut had risen to 25%,

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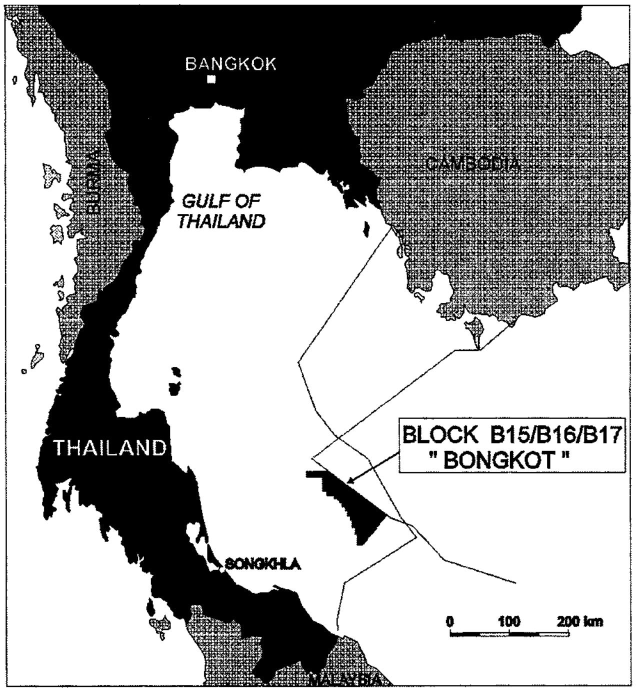

Fig. 1—Map of the Gulf of Thailand showing the location of the Bongkot concession.

and 9 months after the startup of the well, the water cut reached 50%. At this time the liquid production rate from the well was decreased to reduce the volume of water to be treated. After 18 months, the well was producing 900 B/D of oil with a water cut of 46%. The performance of this deviated well led to the consideration of drilling a horizontal well to increase the production rate and the oil recovery.

Reservoir Simulation

A numerical "black-oil" model was constructed and was used to predict the reservoir performance. Data from the existing wells were used to define the reservoir and fluid properties.

Two separate models were used to better reproduce the effects of water and gas coning. For deviated wells, a model with a radial grid was adequate, whereas for horizontal wells, a model with a Cartesian grid was used.[5]

History Matching. To verify the consistency of the model, a simulation of Well BK-4-G was performed with the radial-grid model. This well had been the predominant oil-producing well from the 10-90 reservoir. A good match between the observed rates of oil, gas, and water production and the rates predicted by the model was obtained, proving the validity of the parameters selected.

Well-Performance Prediction. Three development options were studied for the reservoir: drilling a second deviated well, drilling a single horizontal well, and drilling two horizontal wells. For each of these cases, simulations were performed, including sensitivity analyses to optimize parameters.

The cutoff for production was set either at a water cut of 70% or at the end of the year 2000, when gas flow from the platform was predicted to be insufficient for liquid transportation. The results were evaluated in terms of the evolution of the water production rate, the oil production rate, and the ultimate recovery.

Case Descriptions. The three development options had sensitivity studies performed, and these studies are detailed below.

Deviated Well. The drilling of a second deviated well on the structure was simulated. The impact of the flowing pressure on the ultimate recovery was studied for cases of low and high drawdown (24 and 36 bar, respectively).

Single Horizontal Well. The sensitivity to drain length, drain vertical position, and drawdown were simulated.

Two Horizontal Wells. Two drains were simulated. These were assumed to be parallel and to be at the same vertical depth. The length of the drains and the distances between the drains were varied to find the sensitivity to these parameters.

Simulation Results. The results of the reservoir study are summarized below for each of the three cases.

Deviated Well. A maximum recovery of 5.6% was obtained, with a low drawdown on the reservoir of 24 bar. However, water breakthrough occurred immediately, and water cut exceeded the 60% maximum within 2 years.

Single Horizontal Well. The position of the drain had a small impact on the ultimate recovery of oil. A slightly higher oil recovery is obtained with the drain positioned in the center of the oil column. However, the risk of producing water is lower with the drain 2 m below the GOC, and gas coning helps to lift the produced liquid.

The optimum drawdown to maximize recovery was found to be 2 bar. Above this value, water broke through earlier; below this value, the oil rate was too low and the reserves would not be produced before the year 2000 deadline.

Drain length had the most impact on recovery. For similar optimized parameters, a 1000-m-long drain gave a recovery of 15% compared with 8% for a 500-m-long drain. Water breakthrough occurred after 7 months of production and rose to the cutoff value after 4 years.

Two Horizontal Wells. The length of the drain was a critical parameter. Two 1000-m-long drains gave a recovery of 19%, compared with 13% for two 500-m-long drains. Drain spacing also affected recovery, with two 1000-m-long drains spaced 450 m apart yielding 19% recovery and the same drains spaced 225 m apart yielding 16%. Oil production again was optimized at 4,000 B/D. Water breakthrough occurred after 22 months of production and rose to the cutoff value after 3.5 years.

Figs. 5 and 6 present the simulation results of the water-cut and oil-rate evolutions for optimized cases for each of the three development strategies. **Table 1** summarizes the different results.

Conclusion. A horizontal well significantly increases the recovery from the oil rim in comparison with a deviated well. The optimum drawdown is approximately 2 bar. The length of the drain had a strong influence on the recovery and should be maximized. The drain should be positioned 2 m below the GOC to minimize the risk of water production and to maximize gas recovery. If the distance between the drains is maximized, two 1000-m-long drains should yield an ultimate recovery of 20%.

Development Option

Crouse[6] recommends that all technical and economic factors should be taken into account when selecting a reservoir-development strategy. The clear definition of objectives is an essential part of this process.

Objectives. The primary objective was to maximize the reserves recovered from the 10-90 A reservoir while maintaining a low unit cost per barrel. To maximize the oil production rate and to minimize the volume of produced water that had to be treated, the drain was to be positioned so that it delayed water production as much as possible.

There was also a desire to minimize the risks of cost overruns or failure. The decision was made at an early stage, therefore, to select simple, well-proven equipment and to use a simple completion strategy. It was accepted that this strategy would limit well-servicing options, but this was acceptable because of the predicted short production life of the well.

Estimated Unit Costs. To check the viability of each solution, the unit cost per barrel for each option was verified. The results were as follows.

Deviated Well. The cost of drilling and completing a deviated well is estimated at U.S. $1.2 million. With an oil recovery of 5.6%, the cost per barrel was calculated to be U.S. $0.95.

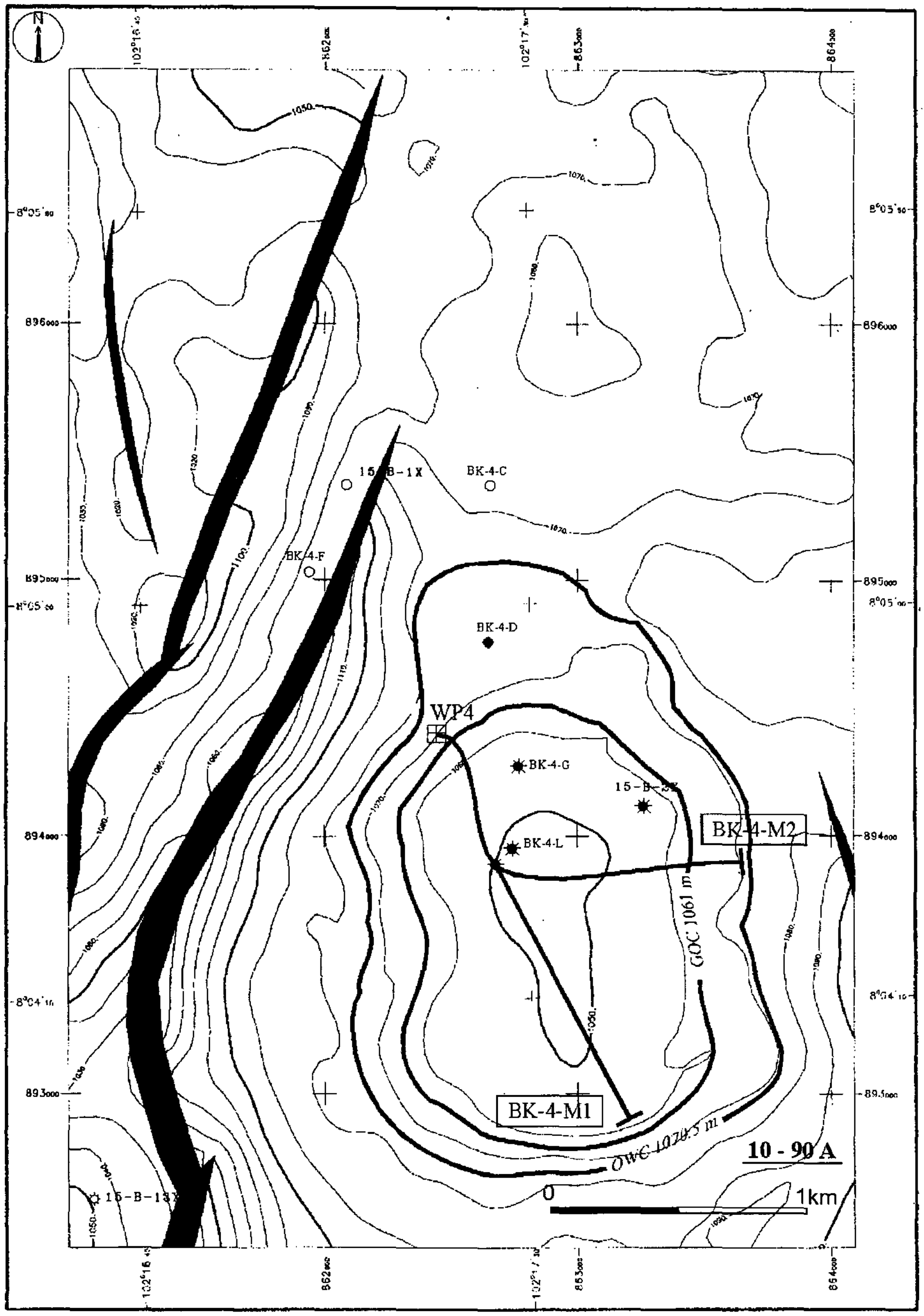

Fig. 2—Isopath map of the top of the 10-90 formation, showing the 10-90-A structure, the GOC, and the WOC. The planned trajectory of the two horizontal drains of Well BK-4-M are shown.

Single Horizontal Drain. For a 1000-m-long horizontal drain, the drilling cost was estimated at U.S. $1.6 million. Oil recovery was simulated to be 15% for a 1000-m-long drain, giving a unit cost of U.S. $0.48/bbl.

Two Horizontal Drains. Two cases were studied: a single well with dual-lateral horizontal drains and two separate horizontal wells.

Two Wells. Costs were estimated at U.S. $3.2 million, double the costs of a single drain well. From simulations, recovery was 19%, and unit cost was, therefore, U.S. $0.76/bbl.

Dual-Lateral. Drilling and completion costs were estimated at U.S. $2.1 million for the dual-lateral option. Recovery was assumed to be equivalent to the two-well case at 19%, or 4.18 million bbl, giving a unit cost of U.S. $0.50/bbl.

Preferred Option. Unit costs showed that the single horizontal drain option and the dual-lateral option were equivalent in cost terms. The option of two horizontal wells was more expensive, but it allowed independent operation of the drains.

The principal barrier to the implementation of the two horizontal wells was the limited availability of slots on Wellhead Platform WP4. Of the 12 slots originally available, six had already been used and the remaining six had been allocated to targets, including one to develop the 10-90 A oil zone. To use two slots to develop the 10-90 A zone would have delayed the production of gas reserves in the area of Wellhead Platform WP4.

The preferred solution was, therefore, the dual-lateral/horizontal well from a single slot. This maximized the recovery from the reservoir at the lowest unit cost and only used a single slot. This reduced the requirement of surface facilities, which is a common reason for the selection of a multilateral well over multiple horizontal wells.[7]

Drain Trajectories. The two parallel drains used for the simulation of the well were rejected as not being economically or technically feasible from a single wellbore. A Y-shaped trajectory was selected that gave good aerial drainage of the reservoir.

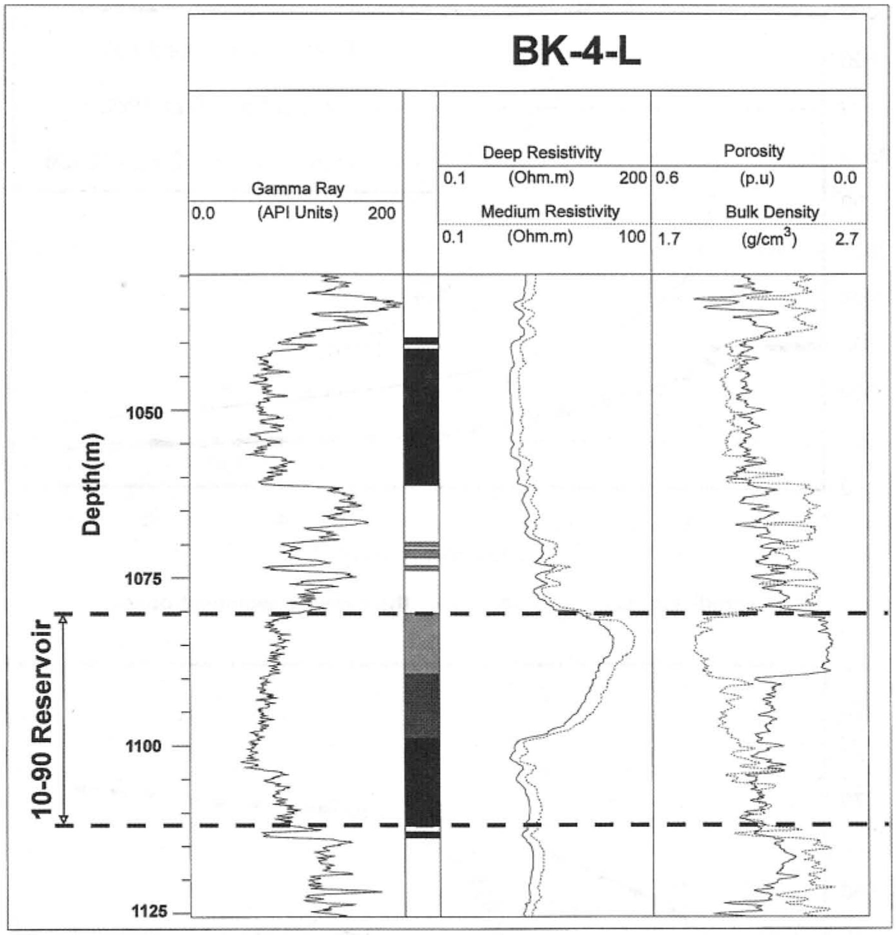

Fig. 3—The 10-90 reservoir as logged in Well BK-4-L.

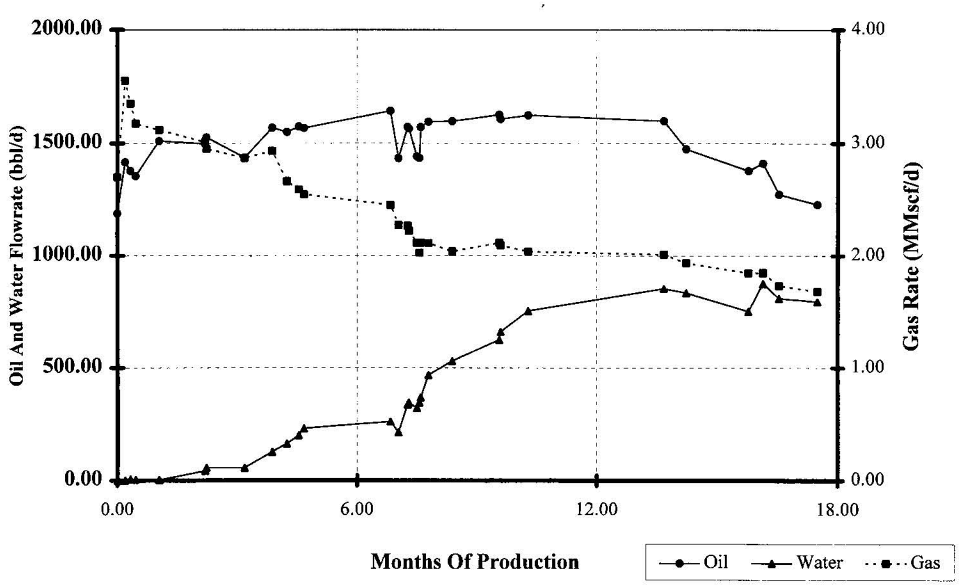

Fig. 4—Production history of Well BK-4-G. Water breakthrough occurred after a short time and subsequently increased with time.

The trajectory selected for the first drain was the extension of a straight line from the platform to the entry point (Fig. 2). Side-tracking of the second drain was planned in the vertical target section and with the drain turned in the horizontal plane, to increase the separation between the wells as quickly as possible. The final azimuth of the second drain was planned to be at 90° to the first drain, giving a wide coverage of the reservoir.

Zone Isolation. To optimize oil and gas recovery and to minimize the risk of early water production, the best position for the drain was 2 m below the GOC. The reservoir was believed to be homogeneous, with no fractures or large variations in vertical permeability. Therefore, with the drain in the correct position, the entire openhole section could be produced. No specific zone would be subject to water breakthrough, therefore, no water shutoff would be performed.

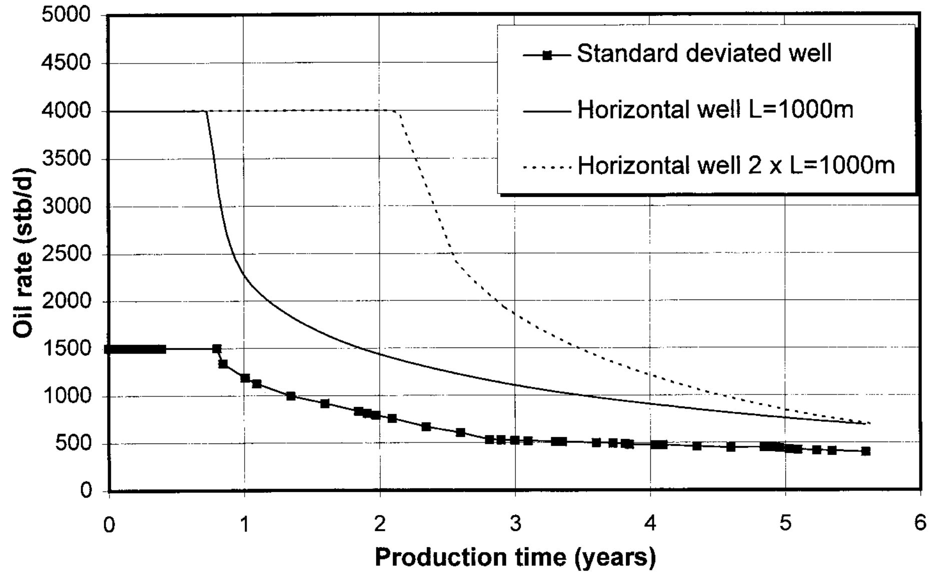

Fig. 5—Predicted oil production rate for the three development options.

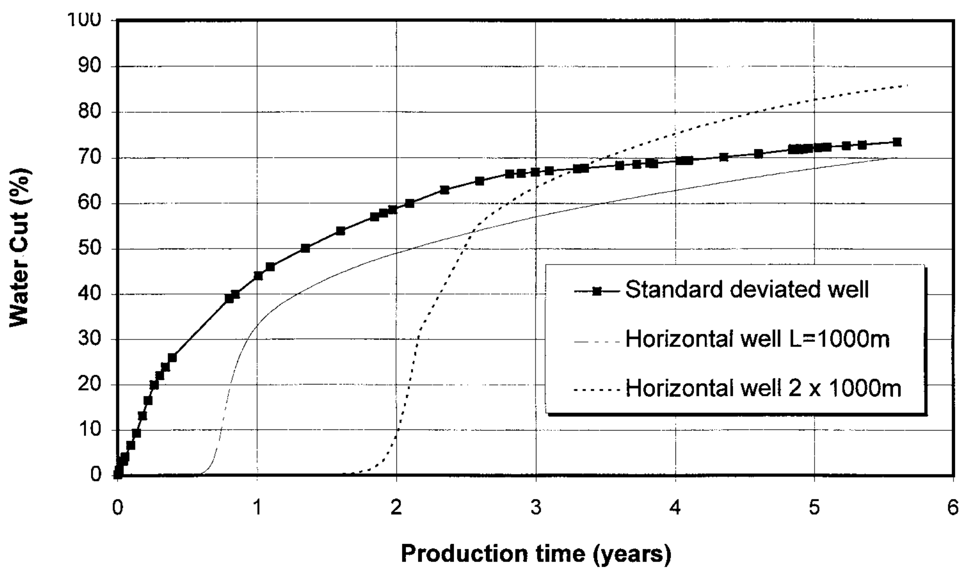

Fig. 6—Predicted evolution of the water cut for the three development options.

The costs and risks associated with cementing and perforating a long horizontal section were evaluated and were unacceptable. An openhole completion was, therefore, selected.

Studies of rock mechanics were carried out, including tests on core samples. The results indicated that, although the formation was poorly consolidated, no problems with formation stability or sand production should occur in the sandstone of the reservoir section. Shale formations, however, presented a higher risk of problems with hole stability.

Analysis showed that the presence of shaly intervals in the reservoir could not be ruled out. To ensure that the drain remained open if formation failure occurred in shaly sections, a slotted liner was selected.

Independent Operation of Drains. Systems that allow the isolation of two or more horizontal drains have been developed.[8] These "sealed-root" systems allow the independent operation of the drains, with either drain being isolated if production problems occur. By partially cementing the second liner, the localized drawdown in the vicinity of the first drain could have been reduced. The system also could have allowed selective re-entry, if required.

After consideration, the sealed-root system was rejected for the following reasons.

Risk. The implementation of a sealed-root system required more complex operations to be carried out. These operations included the cementing of at least part of the liner and the milling of the liner stub. The sealed-root systems were evaluated and were found to be a relatively new technology with a significant risk of failure. That risk could result in costly remedial work or in the possible loss of the well.

Cost. The more complex operations that were required to implement such a system would have increased the well duration by at least 15%. This was seen as uneconomical.

Well-Servicing Requirements. No interventions were envisaged in either drain, and no stimulation was necessary.

Confirmation of Contact Depth. The confidence in the depths of the GOC's and in the water/oil contact (WOC) from offset wells was high. However, the critical nature of the position of the drain led to a well profile that could confirm the position of the contacts.

The drilling of a pilot hole was rejected because of cost. Instead, the approach to the reservoir was designed so that it confirmed the contact position.

The building phase to the horizontal was designed so that the inclination was at 85° at the top of the reservoir. A formation-

TABLE 1—SIMULATION RESULTS FOR THE VARIOUS CASES STUDIED

Well	Cumulative Oil (thousand STB)	Oil Recovery (%)	Gas Recovery (%)	Water Cut (%)	Date
BK-4G	1,271	5.6	14	70	November 1998
L = 500 m	1,813	8	22	60	December 2000
2 × L = 500 m	2,744	13	23	70	December 1999
L = 1000 m	3,025	15	22	66	December 2000
2 × L = 1000 m	4,170	19	18	70	December 2000

evaluation-measurement-while-drilling (FEMWD) tool was to be used to identify the reservoir and the fluid contacts by providing real-time gamma ray, resistivity, and neutron-density data.

It was planned that as soon as the FEMWD tool identified the GOC, the well would be steered so that the end of the phase was at 90° and was at a position 2 m below the GOC. This gave a hook-shaped profile (see **Fig. 7**). There was no plan to pass through the WOC because the thickness of the oil rim had been proved on delineation wells.

Well Design

Well Architecture. The well was designed to achieve the principal objective of minimizing water production by correctly positioning the drain in the oil reservoir. The secondary aim of minimizing technical risks also was taken into account when selecting equipment.

Horizontal Drains. Tubing performance analysis indicated that tubing that was 3½-in. outside diameter was sufficient to allow an oil production rate in excess of the predicted 4,000 B/D. It was, therefore, possible to drill the horizontal drain with a hole of 6 in. or less in diameter. However, a hole with a diameter of 8½ in. was selected to maximize the tools that could be used for drilling and completion.

Drilling Equipment. The complete range of FEMWD tools was available for the hole size of 8½ in., including motors with inclination-at-bit sensors. This equipment was seen as essential to piloting the drain in the narrow target window. The primary tool for trajectory guidance was inclination, because the fluid contacts were the only reference points. Density and resistivity tools gave an indication if the contacts were penetrated, but they gave little warning of an approach to the contacts.

The optimum drain position of 2 m below the GOC was used to define a vertical target window of 0 to 2 m below the GOC. This window ensured that there was minimum risk of early water breakthrough. The critical nature of the vertical position of the drains led to the selection of a motor with an inclination sensor mounted close to the bit. This sensor gave a constant readout of the well inclination, which allowed the well to be piloted in the required window.

Liner Equipment. A 7-in. liner could be run in a 8½-in. hole. This diameter allowed a 3½-in. inner string to be used to circulate at the shoe of the slotted liner if an obstruction was encountered. Slots that were 0.028 in. wide and 1.5 in. long were cut on a 180° phasing with two slots per linear foot of casing. These slots were calculated to permit the anticipated flow from the reservoir. It was

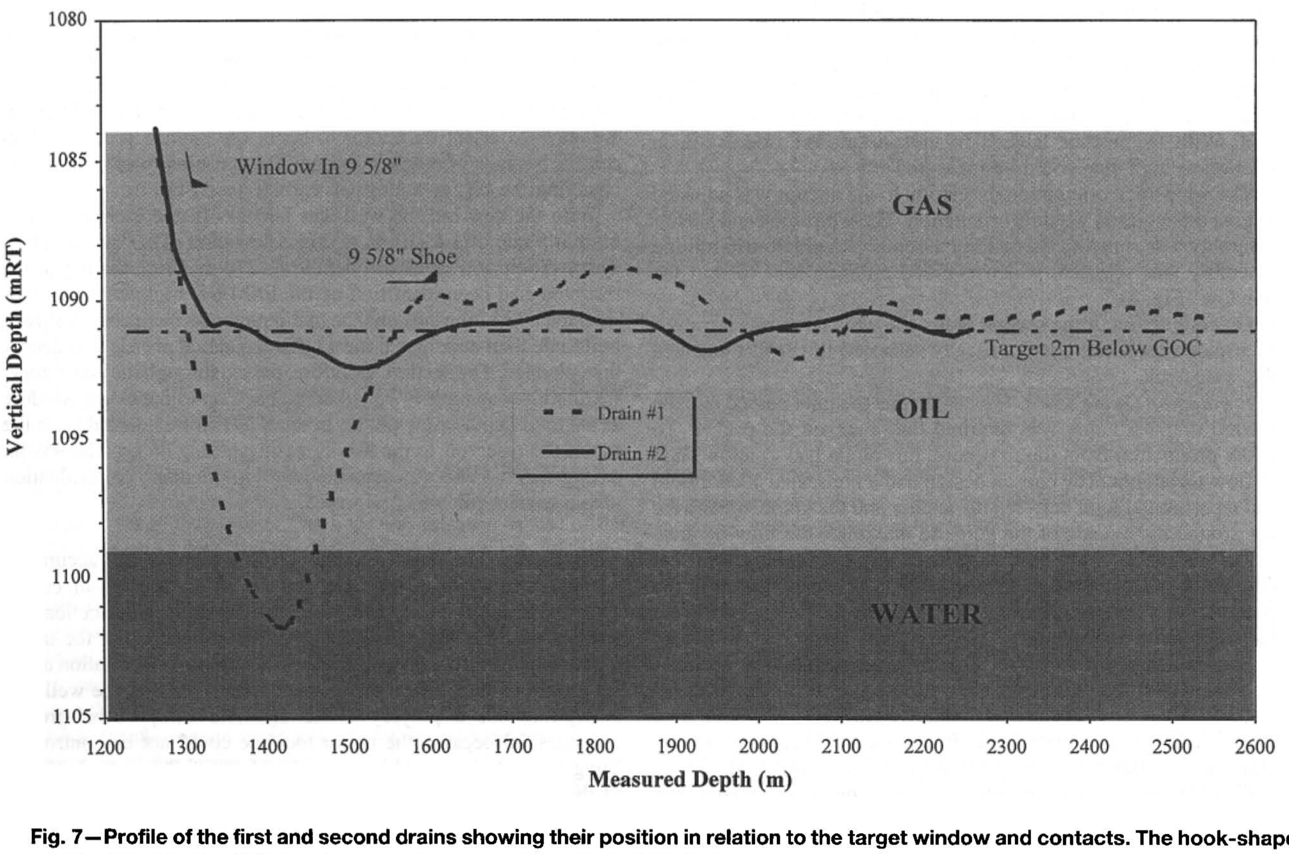

Fig. 7—Profile of the first and second drains showing their position in relation to the target window and contacts. The hook-shaped profile drilled in the 12¼-in. phase can be seen at the start of Drain 1.

not anticipated that this liner would prevent sand production if formation failure occurred.

A hydraulic running tool was used that allowed rotation to reduce drag if required. Because the liner was horizontal over its entire length, the risk of upward movement was analyzed as being low. Therefore, no liner hanger was used.

Drilling Fluid. A low-toxicity, oil-based mud was selected as the drilling fluid for the horizontal drains. Studies showed that this fluid minimized the reservoir damage and avoided problems with shale intervals.

A mud weight of 1.10 specific gravity (SG) was used while drilling the drain to minimize losses. However, when pulling out, a 1.15-SG mud weight was displaced into the well to ensure formation stability. Oil-based mud gave the additional advantage of reducing the friction factors. This was especially important when running the liners.

Intermediate Section. This section was critical to the success of the well because it contained the build section to horizontal. The selected hole size of 12¼ in. allowed a full-suite FEMWD to be used to provide real-time information on the formation type and fluids. The correct vertical positioning of the 9⅝-in. casing shoe was essential to the success of the drain.

The hook-shaped profile meant that the well would pass through, or close to, the water-bearing formation. To ensure that there would be good cement isolation around the 9⅝-in. casing, centralization was optimized in the reservoir section.

Drilling Fluid. A water-based polymer system was used in the phase with a 12¼-in. hole size. This fluid gave good shale inhibition, which ensured hole stability.

A low mud weight was initially used in the slant section. Density was increased to 1.20 SG during the buildup to horizontal. The higher mud weight ensured that no problems with formation stability occurred.

Surface Section. The surface 13⅜-in. casings were set at 400 m TVD at mean sea level in a batch operation to improve efficiency. In the 17½-in. phase, the wells were kicked off to increase well separation. The leak-off test at the 13⅜-in. shoe was sufficient to drill the hydrostatic reservoir.

Sidetrack Assembly. To sidetrack the well in the 9⅝-in. casing for the second drain, a retrievable whipstock and packer assembly was selected. At the sidetrack depth, the well was at 80° inclination; this ruled out the use of wireline tools. After running the packer, its orientation had to be verified. This survey was performed by running the anchor assembly with a measurement-while-drilling tool. With the anchor latched in the packer, the orientation in relation to high side could be measured

The whipstock orientation in relation to the anchor was adjusted to give the required window orientation. The whipstock and anchor assembly was run with the milling assembly. A single-trip milling assembly was selected, which avoided multiple runs to mill the window (**Fig. 8**).

On completion of the second drain, the whipstock was retrieved by use of a tool with a hydraulically activated finger that engaged the whipstock.

Production Guide Stock. To ensure that the liner passed into the second drain, a guide was required that engaged the packer. To allow production from the first bore, this guide had to allow fluid to flow through it. The chosen design had a nonsealed anchor bore and a perforated joint between the anchor and the guide. Slots were cut around the outside of the guide to maximize the flow-by area.

This assembly was run on the liner using a running tool that doubled as a float shoe. Once the guide had been engaged in the packer, it was sheared off the running tool and the liner was run into the sidetracked hole.

Suspension of the Drains. Reservoir-damage studies were carried out with different fluids in the wellbore to evaluate the potential damage. These studies showed that the low-toxicity oil-based mud used for the phase caused very little damage. Therefore, no displacement of this fluid was performed before completion.

Completion. Production tubing (3½-in. outside diameter, 9.2 lbm/ft) was used with a hydraulic set production packer set in the deviated part of the well for completion (**Fig. 9**). Below the packer, a tailpipe stabbed into the top of the second liner. This continuity allowed entry into the second drain, if required.

Future Abandonment. Individual isolation of the drains will not be possible because of the simple completion strategy that was chosen for the well. Simultaneous abandonment of both drains will, therefore, consist of plugging back the 9⅝-in. casing in the horizontal section. No attempts will be made to isolate the drains from each other because they are at the same vertical depth in the same continuous reservoir.

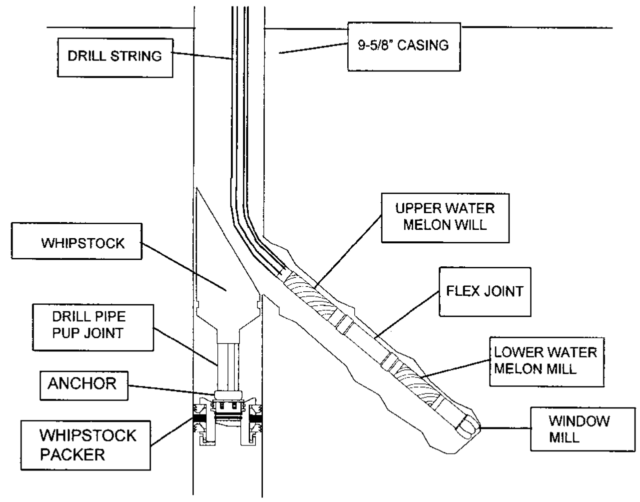

Fig. 8—Sidetrack assembly used for milling the window.

Operations Review

The 13⅜-in. surface casing had been set at a measured depth of 401 m in Slot M of Wellhead Platform WP4 during the first phase of drilling on the platform in March 1995. Operations to drill the horizontal well started in late May 1996.

The 12¼-in. Intermediate Section. Using a steerable motor assembly and a polycrystalline diamond compact bit, the inclination was built to 20°. This inclination was held to 875 m, at which depth the final buildup to horizontal was to begin at a rate of 1.5°/10 m. Attempts to orient the motor to begin the kickoff proved unsuccessful because of reactive torque. This problem was resolved by changing the bit for a tungsten carbide insert bit.

With the new bit, the well was kicked off and inclination was built at a rate of 1.4°/10 m, giving a deviation of 80° at the top of the reservoir at a measured depth of 1270 m. Once the top of the reservoir had been identified by the FEMWD tool, the motor was oriented to the high side and the inclination was increased. A slower build rate than anticipated meant that the actual profile was deeper than planned. The section, therefore, passed through the water zone. Inclination was built to 96° to come back up to the target window at the total depth of the phase. In total, 271 m was drilled from the top of the reservoir to the 9⅝-in. casing setting depth. The 9⅝-in. casing was run and was cemented without incident. No evaluation of the cement job was performed.

First Drain. The data from the 12¼-in. section had accurately defined the position of the GOC and the WOC. The 9⅝-in. casing shoe had been set 2.5 m below the GOC. In the 8½-in. section, the vertical position was monitored and was maintained in the target window using directional data only. The real-time inclination at the bit proved to be an ideal tool for accurately piloting the well. An attempt to use a polycrystalline diamond compact bit proved unsuccessful because the motor toolface could not be controlled. Tungsten carbide insert bits were, therefore, used over the majority of the drain.

To correct the well azimuth and to avoid an area of poor reservoir, the drain was turned to the left by 30° from just beyond

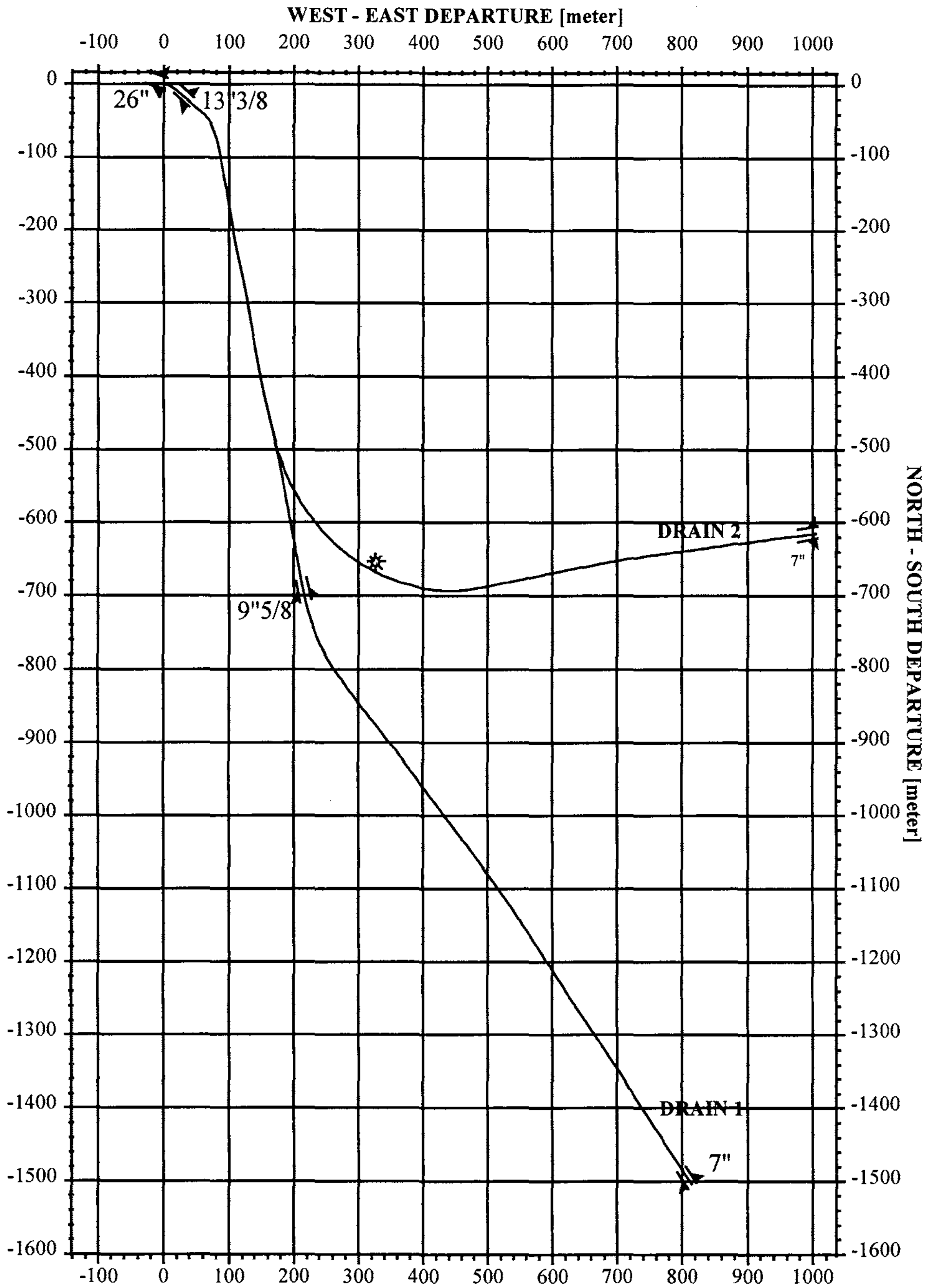

Fig. 9—Plan view of the two drains as drilled.

the 9⅝-in. shoe (**Fig. 10**). This modification of the azimuth gave a high degree of confidence that the turn required in the second drain was feasible.

With the drain successfully drilled, the 7-in. slotted liner was run with a 3½-in. drillpipe inner string; no rotation or circulation was required to get to the bottom. The liner was released by use of the hydraulic running tool, and the inner string was pulled out.

Second Drain. The successful piloting of the first drain allowed the second drain to be started with a higher degree of confidence.

Sidetrack. The hook profile of the 12¼-in. phase (Fig. 8) gave two points at which the 9⅝-in. casing was in the target window; the first was 250 m above the shoe, and the second was at the shoe. The sidetrack for the second drain was, therefore, planned for the first intersection of the target window.

The whipstock packer was set at 1293 m using the hydraulic running tool; the inclination of the well at this point was 82°. The orientation of the packer was checked with the anchor and a measurement-while-drilling tool. The whipstock orientation was set at 15° left of the high side before the whipstock and anchor assembly was run. After anchoring the whipstock in the packer, a window was milled in the casing (Fig. 7). The mill became blinded by formation and debris, and it was pulled out and replaced with a second mill to complete the window.

The drilling assembly that had been used for the first drain was reused, and it drilled successfully to total depth. The azimuth was turned through 85° in 460 m, giving an average turn rate of 1.8°/10 m. A single tungsten carbide insert bit was used for the entire drain. No problems were experienced with passing equipment through the window.

Running Second Liner. On completion of the drilling, the second drain whipstock was retrieved with the hydraulic latch-retrieving tool. The production guidestock was run on the slotted liner and was stabbed into the packer, and the liner was sheared off the guide and was run into the second drain. Again, no problems occurred, and it was not necessary to circulate or rotate the liner.

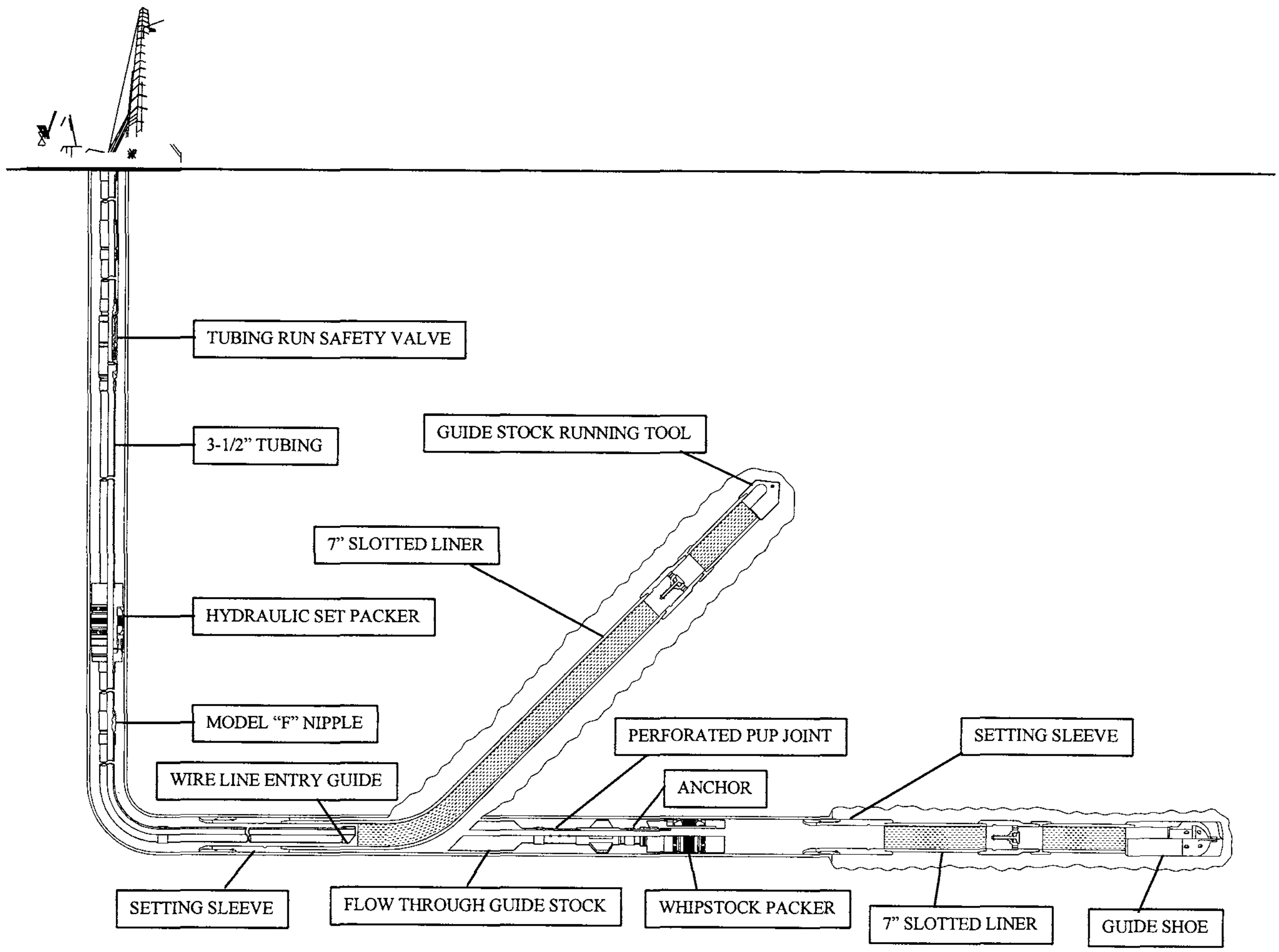

Fig. 10—Schematic of the completed status of Well BK-4-M.

Suspension. The completion of the wells that were drilled on the platform was performed in a batch at the end of the platform; therefore, it was necessary to suspend the well. A storm packer and kill string were used, with the bottom of the kill string just above the liner in the second drain.

Completion. Three weeks after suspension, the kill string was retrieved and the mud homogenized by circulation. The mud was found to contain high concentrations of gas, which were caused by the migration of the reservoir fluid. This gas was circulated out, and the stability of the well was confirmed before the kill string was pulled out. Finally, the well was displaced to a 1.15-SG brine, just above the second liner.

The completion was run, and it landed without problems. Before setting the packer, diesel was displaced into the tubing down to the wireline entry guide to allow the well to be started up without the use of coiled tubing.

Cleanup. The well was opened up to the burner, and the diesel was flared off. The oil-based mud in the two drains was lifted without problems and was also flared off. After cleaning up the well by using the burner for several hours, the amount of solid and water in the effluent was sufficiently low that the well could be connected to the production header. Electronic gauges were run into the well to measure the drawdown during subsequent tests.

Well Results

Drilling Operation Performance. Two drains were drilled, yielding a total drain length of 1977 m. Total operations on the well, including drilling and completion, lasted 21 days.

First Drain. The total length of the drain from the 9⅝-in. shoe to total depth was 1002 m. Several short, shaly sections were encountered; however, 93% of the drain was in the sandstone reservoir. The entire length of the drain was in the oil zone, with 85% of the drain in the 2-m-thick, vertical-target zone. At its closest point, the well was 6.8 m above the WOC.

From the start of the well to the beginning of sidetracking operations, all operations took a total of 10.9 days.

Second Drain. The total length of the drain from the 9⅝-in. window to total depth was 975 m. Few shaly sections were seen in this drain, and 97% of the drain was evaluated as sandstone. The entire length of the drain was in the oil zone, with 50% in the 2-m-thick, vertical-target zone. At its closest point, the drain was 6.6 m above the WOC. Operations to sidetrack, drill, and run the liner in the drain took a total of 7 days.

Completion. Completion of the well took 3.1 days, which included much circulation time to reduce the gas levels in the mud after suspension.

Well Cost. Total direct costs for drilling and completion of the well were U.S. $2.1 million, excluding logistical and overhead costs. This cost compares with approximately U.S. $1.2 million for a standard deviated well on the field.

Production Performance. After cleanup to remove the oil-based mud from the two drains, the well was put into production. Initially, the well produced 4,000 B/D of oil with no water. The GOR of 450 scf/STB was equivalent to the solution GOR. Gauges that were observed during the initial tests showed a drawdown of approximately 0.1 bar on the reservoir at an oil flow rate of 4,000 B/D. The results from the initial tests showed that the drain had been positioned successfully to avoid water or gas coning.

After 6 months of production, the well was producing at a rate of 4,700 B/D and had produced a total of 800,000 bbl of oil and no water. The GOR was still approximately 450 scf/STB.

Conclusion

By implementing a dual-horizontal well in a 10-m-thick oil rim in the 10-90-A structure, simulations indicate that the recovery of oil will be 19% of the initial reserves compared with 5.6% for a deviated well. This increase represents a volume of 3 million bbl of oil. The additional recovery is achieved by delaying water breakthrough from the active aquifer that underlies the reservoir.

The drains were drilled successfully, staying within the target window 2 m in height over the majority of the drain. No major technical breakdowns occurred during either the drilling or the completion. Drilling costs were estimated to be U.S. $0.47/bbl for this well, which was comparable to the cost of a single horizontal drain and was two-thirds the cost of a deviated well.

After 6 months of production, the actual drilling results confirmed the simulations, with no water production to date and gas rates that are equivalent to solution gas.

The well was the first horizontal well drilled in the field, and, as such, it used proven technology to drill the two drains. This approach minimized the risk of failure and of cost overruns.

A dual-drain horizontal well was the ideal solution, because no spare slots existed on the platform. Recovery could be increased without costly modifications to the platform or a loss of gas production.

Other oil rims containing smaller volumes of oil have been identified in the field. The challenge for the future will be to maximize recovery while keeping well costs low enough to allow economic production.

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SI Metric Conversion Factors

°API	141.5/(131.5+°API)		= g/cm^3
bbl	× 1.589 874	E−01	= m^3
bar	× 1.0*	E+05	= Pa
ft	× 3.048*	E−01	= m
ft^3	× 2.831 685	E−02	= m^3
in.	× 2.54*	E+00	= cm
lbm	× 4.535 924	E−01	= kg
mile	× 1.609 344*	E+00	= km

*Conversion factors are exact.

SPEDC

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