Rapid Planning and Execution of the First Multilateral Well in the Gulf of Thailand: Results and Lessons Learned

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Summary

In early 2006, Chevron International E&P drilled and completed the first multilateral well in the Gulf of Thailand. Routine development drilling in the Kaphong field of the Pattani basin unexpectedly discovered two production horizons that possessed reservoir characteristics and sufficient oil reserves to make each a viable horizontal-well candidate. At the time, however, only a single drilling slot was available on the platform; thus, dictating that only one wellbore could be drilled to tap both reservoirs. Further complicating the problem was that the drilling rig that discovered the horizons would be moving to a new platform 5 weeks after it was understood by reservoir engineers, geologists, and geophysicists that multiple horizontal-well candidates existed.

This paper chronicles the rapid processes that took place to evaluate, plan, and execute the first multilateral well in the Gulf of Thailand. More importantly, this paper captures the unintended consequences (both good and bad) that came with executing this project so quickly. This includes an analysis of how decision making, project planning, and ultimate execution where affected by the short time window available. From this, we discuss lessons learned that may be universally applicable when rapidly expanding the use of technology in a remote region of the world (regardless of how small that expansion is).

Introduction

The Pattani basin in the Gulf of Thailand is a region containing significant oil and gas reserves. Chevron Thailand has been producing from this basin since 1981. Although predominantly a gas-producing region, the northern sector of the Pattani basin is oil-rich and has been the focus of significant development in recent years. The push for greater oil development has lead to sizeable production increases in the last 4 years. One key component to these production gains is the use of horizontal wellbores. Although only 20 standalone horizontal wells had been drilled before drilling the multilateral well discussed in this paper, they collectively contribute 11% of the 107,000 bbls/day oil production from Chevron's Gulf of Thailand operation while making up only 4% of the well count.

With the strength of their oil-rate contribution, it makes sense that Chevron Thailand would want to drill as many horizontal oil producers as geologic reality would permit. It is within this setting that Chevron Thailand unexpectedly found two pay zones atop each other (separated by, 400 ft true vertical depth (TVD) that were both legitimate candidates for development using horizontal wells. This discovery occurred in February of 2006 while drilling a series of 20 nonhorizontal oil wells from the Kaphong Delta satellite production platform (KPWD) within the Kaphong oil field. The problem, however, at the time of this discovery is that only one of the 20 available drilling slots was still undrilled, thus forcing a difficult choice to be made. Do we stay within our currently well-defined technology-knowledge envelope and drill a single-horizontal wellbore, leaving one of the two producing horizons fallow until it can be drilled at a later date from an abandoned drilling slot? Or, do we step slightly beyond our local experience base and attempt drilling a multilateral wellbore to immediately maximize the oil-rate potential presented by these two producing horizons? Given ample time, all the necessary engineering steps for making this decision can be performed to arrive at a logical and well-defined solution. In this instance, however, time was not abundant. From the time it was understood that two economically viable horizontal-well targets existed, only 5 weeks remained before the drilling rig must either spud this well or move to another platform. This, in turn, compressed the time window for deciding how to proceed with this project to only 2 weeks, allowing the balance of time for appropriate predrill engineering and operational planning.

In the end, the first multilateral well in the Gulf of Thailand was successfully drilled, completed, and put on production—but not without its share of difficulties and missteps. Implementing a technological step forward (even if it is a small one) is never without risk. Introducing such a step into a new country or region can only add to the possible risks. But doing it in a compressed time frame (though necessary in some cases) certainly introduces the greatest risk. From project inception to final completion, the team tasked with drilling this well understood this fact. Time limits, though, demand that trade-offs be made between execution readiness and planning completeness, with some of those trade-offs being unintended. The purpose of this paper is to describe the intended and unintended trade offs that occurred, their overall impact on the project, and how they relate to the environment in which this project was conceived and implemented.

Structural-Geology Description of the Pattani Basin

The Pattani Basin in the Gulf of Thailand is a pull-apart rift basin composed of a collection of Miocene stacked channel sands interrupted by normal (i.e., extensional) faulting. The ultimate result is a 450-km-long series of north/south trending graben and horst structures bounded by terraced fault blocks **(Fig. 1).** The faults act both as a pathway for hydrocarbon upward movement from deep-source rocks, and as a trapping mechanism within the terraced fault blocks. To maximize the possibility of encountering trapped oil and gas, nonhorizontal wells in the terraced-fault blocks are typically drilled parallel to the updip hydrocarbon-trapping faults and approximately 200 ft away (see Fig. 1) to ensure that the fault is not crossed (a worst case scenario). However, within this geologic system, there are also shallow sand packages that possess sufficient permeabilities, porosities, and areal extent that they are best developed using horizontal wells—with the horizontal being placed as near to the trapping fault as is practical (i.e., only 100 ft away because the shallower zones have greater seismic reflectivity relative to deeper zones, thus allowing a more accurate determination of fault position).

Traditional Horizontal Well Design

Design and drilling of a single open hole horizontal well starts with the assumption that the horizontal production hole section will be drilled using a 6⅛-in. bit. Starting with that end product in mind,

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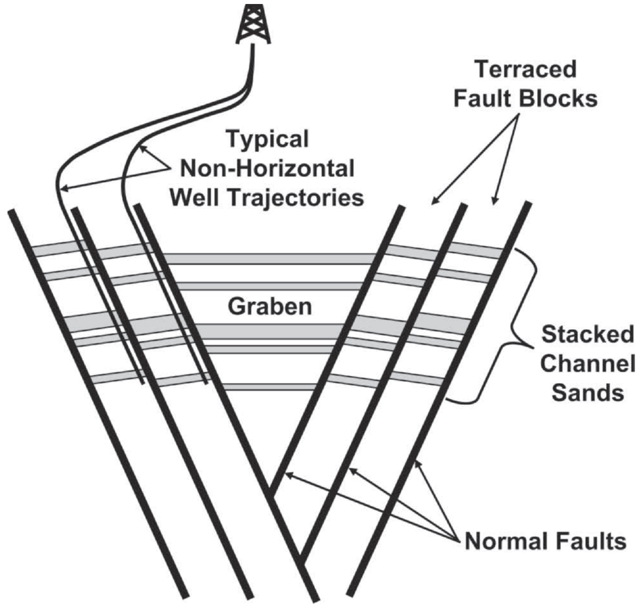

Fig. 1—Schematic of Pattani Basin typical structural geology and non-horizontal well trajectories.

a method commonly used by Chevron Thailand to drill and complete horizontal wells is to

• Drill a 15¾ in. surface hole section to 1,000 ft TVD. Cement 13⅜ in. casing at total depth (TD).

• Directionally drill a 12¼ in. intermediate hole section to a point deep enough to contain any well-control incident that might occur while drilling the subsequent hole section into the pay zone. Cement 9⅝ in. casing at TD.

• Directionally drill an 8½ in. intermediate hole section to a horizontal orientation within the target pay zone using a synthetic-paraffin drilling fluid (SPDF). Cement 7 in. casing at TD.

• Drill the 6⅛ in. horizontal using a $CaCO_3$-laden SPDF.

• Lastly, a 3½ in. production tubing with gas lift mandrels and packer is installed, and the well is put on production.

Before drilling the multilateral well, seven openhole horizontal wells had been drilled and completed in this manner, with all using the same respective drilling-fluid type for each interval. It is also noteworthy to note that no significant directional-drilling problems were encountered during the drilling of the previous seven similarly-drilled horizontal wells (in any of the various hole sections).

Horizontal-Target Discovery and Characteristics

The 20-well KPWD drilling program commenced mid-November 2005. There was little expectation from geoscientists that any horizontal-drilling prospects would be encountered. The wells, however, were drilled in two 10-well batches (our standard procedure) so that in the unlikely event of discovering horizontal-well targets during the first batch of wells, there would still be adequate time to plan for the drilling of any horizontal wells at the end of the second batch of wells. **Fig. 2** displays the two multilateral-well target horizons that were discovered (i.e., the 65-1 and 69-1 sands) and the wells that penetrate them. The first two wells to penetrate the 65-1 and 69-1 sands were KPWD-11 and KPWD-12. This occurred in late December 2005 while drilling the first batch of 10 nonhorizontal wells. Their penetration positions place KPWD-11 and KPWD-12 at or near the heart of what will be the desired location for openhole producing laterals, with each sand having a thickness of 30 to 40 ft **(Figs. 3 and 4).**

It was not until the KPWD-29 penetrated these zones on 1 February 2006 and defined the northern extent of the oil pay (see Figs. 2, through 4) that it became clear that both zones were candidates for production by means of openhole laterals. Two weeks later, the KPWD-13 delineated the southern extent of the oil pay. Because these first four penetrating wells were designed to produce from a terraced fault block, they were drilled 200 ft away accordingly from the fault. The result is that the apex of the 65-1 and 69-1 sand structures lay approximately 20 and 50 ft, respectively, above the highest penetration (i.e., KPWD-11 at 6,597 ft TVD in the 65-1 sand and 6,997 ft TVD in the 69-1 sand). The plan for tapping these reserves, regardless of two standalone horizontal wells or a single multilateral well, was to place openhole laterals updip of offset wells in both the 65-1 sand and the 69-1 sand, with the laterals being approximately 100 ft away from the fault. Moving the laterals any closer to the fault was thought

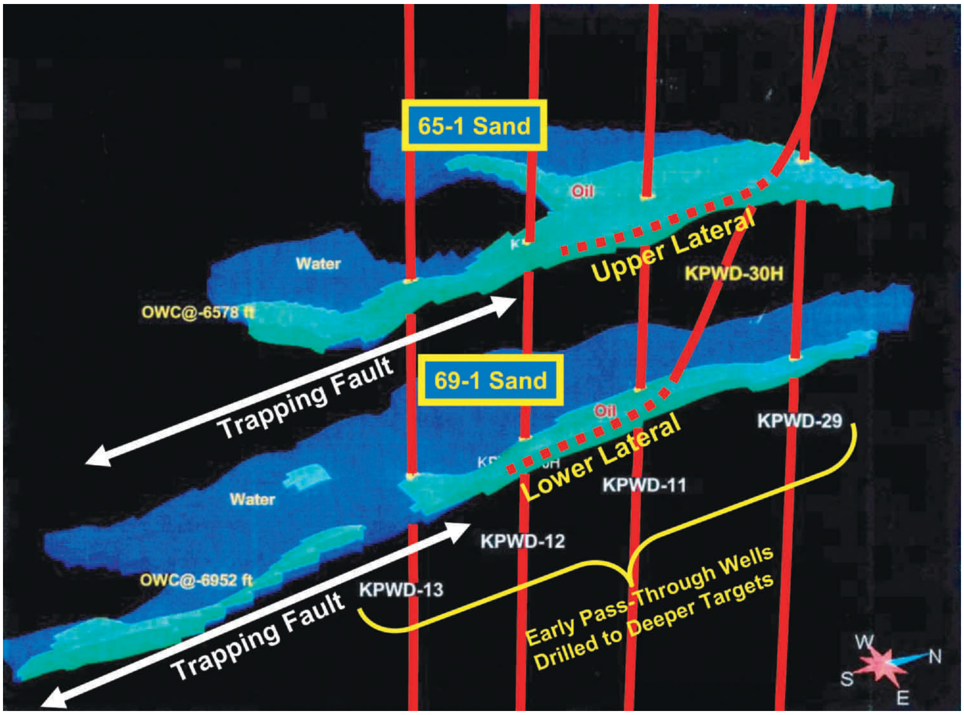

Fig. 2—Target horizons (i.e., 65-1 and 69-1 Sands) for KPWD-30H multilateral well.

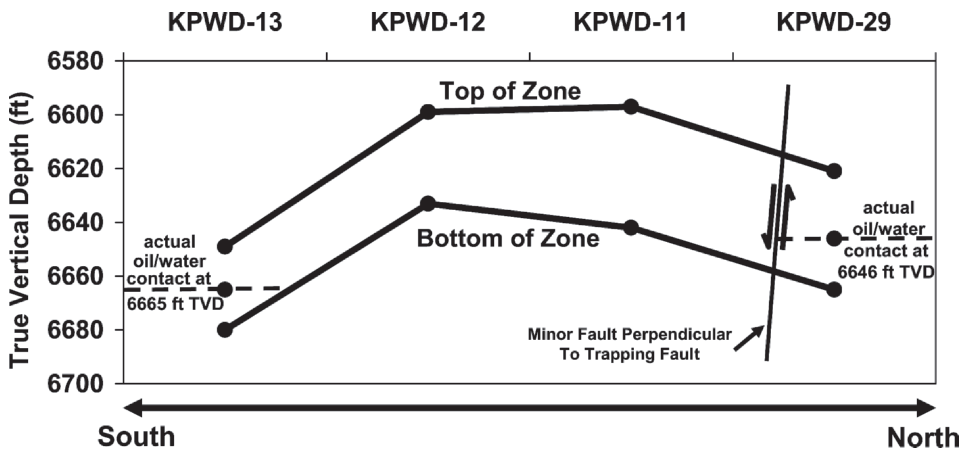

Fig. 3—Cross-section of 65-1 sand and OWCs approximately 200 ft from fault.

to introduce too much risk in terms of accidentally drilling across the fault.

Figs. 3 and 4 show the location of the ONCs in both sands. In the 65-1 sand, both of the structurally superior wells (i.e., KPWD-11 and-12) are above the OWC, while the downdip periphery wells (i.e., KPWD-13 and 29) enter into the water leg of the sand. In the 69-1 sand, the situation is the same, with the exception that the KPWD-11 penetrates the edge of this sand's water leg. None of these wells indicated the presence of gas/oil contacts.

Project Rationale and Decision-Making Environment

Once the KPWD-29 log data had confirmed the presence of two viable horizontal-well targets, discussions immediately ensued to choose which one of the two targets to drill, considering that only one unused drilling slot was available on the platform. Within 1 week, the idea of possibly drilling a multilateral well was introduced and actively debated. After having thought through the various rationales and methods for applying multilateral technology (Hogg 1997; Brister 2000; DeMong et al. 2002), two camps quickly formed within the project team, one supporting the idea of drilling a multilateral well (this concept being labeled Concurrent Production) and the other camp supporting drilling a single horizontal in the 69-1 sand, with subsequent drilling of the 65-1 sand after the former is depleted (this concept being labeled Sequential Production). To quickly resolve which option held the most value without unreasonable risk exposure, the project team convened to compare the pros and cons of both options. The team understood that they must come to a conclusion quickly to allow sufficient time for Drilling Engineering to formulate plans and procure equipment. **Table 1** summarizes the team's findings at this point into three major discussion categories: (1) reserves recovery, (2) technology and implementation, and (3) economics. Within each category, significant (and sometimes slightly contentious) debates occurred, and rarely did any positional argument clearly outweigh its counterargument. We elaborate on each discussion category in the following three sections in an attempt to capture the mindset of the team at this phase of the project.

Reserves Recovery. The debate over reserves recovery focused on the competition between faster/higher-risk reserves recovery and slower/lower-risk reserves recovery. The Concurrent Production scenario obviously recovers reserves faster by way of the multilateral well. Its associated risks come in the form of gas lifting the 69-1 sand 1,000 ft TVD shallower than would otherwise be possible and commingling production from the 65-1 and 69-1 sands. Developing these sands using a multilateral well, consequently, forces gas lifting to occur above the upper lateral **(Fig. 5),** rather than deeper through the use of a standalone horizontal well to produce the 69-1 sand. Initial estimates indicate that production by means of a multilateral well reduces recoverable reserves from the 69-1 sand by 5%.

Less easy to quantify is the possible loss of reserves caused by commingling production from the 65-1 and 69-1 sands. The great unknown here is the pore-pressure-decline rate that each zone will experience. The structural geology of the Pattani basin is such that individual hydrocarbon accumulations are not particularly large because of significant faulting and can have great areal variability as a result of their fluvial deposition environment. This results in a highly uncertain pore pressure-decline rate. As shown in Fig. 5, our multilateral-well design does not attempt to segregate production from the two laterals through the use of two tubing strings. Therefore, disparate pore pressure-decline rates could result in premature flow restrictions for the zone with the more rapid pres-

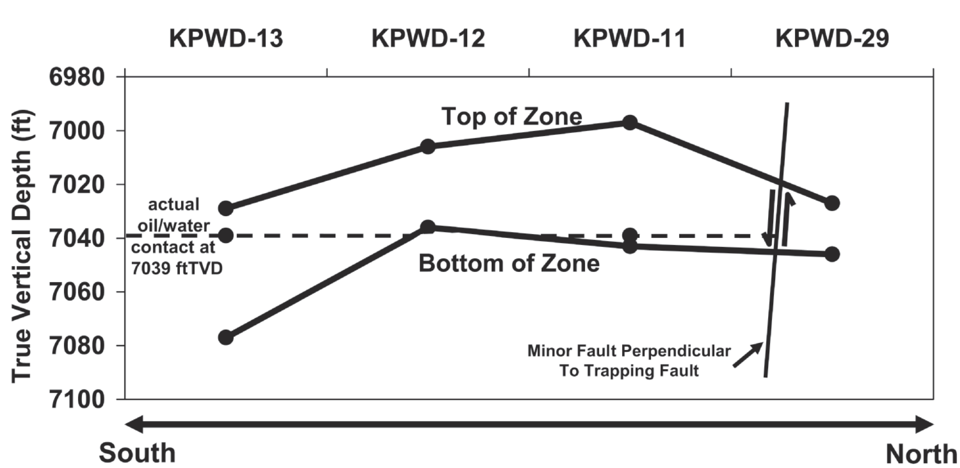

Fig. 4—Cross-section of 69-1 sand and OWCs approximately 200 ft from fault.

TABLE 1—COMPARISON OF PROS AND CONS CONCERNING DRILLING TWO STAND-ALONE HORIZONTAL WELLS SEQUENTIALLY (DUE TO ONLY ONE DRILLING SLOT BEING AVAILABLE) OR DRILLING ONE MULTILATERAL WELL. CONSTRUCTED BY THE PROJECT TEAM DURING EARLY PROJECT SANCTIONING DISCUSSIONS

Concurrent Production From 69–1 and 69–5 Zones Via 1 Multilateral Well		Sequential Production From 69–1 Then 69–5 Zone Via 2 Horizontal Wells (2nd Drilled After 1st Is Depleted)	
Pros	Cons	Pros	Cons
Reserves Recovery			
Faster reserves recovery.	Recovery reduced via inability to gaslift deeper.	Recovery maximized via ability to gaslift deeper.	Slower reserves recovery.
	Risking reserves by commingling production.	No reserves risked since production not commingled.	
	Not enough time to fully simulate effect of commingling production. Thus, we do not completely understand the amount of reserves at risk.		
Technology and Implementation			
TAML Level 2 multilateral junction. Not a **huge** technological leap (~1,000 installed globally to date).	Very short time to develop drilling and completion plan and mobilize necessary tools and expertise to execute.		
	Higher risk of failure due to lack of local expertise (unanticipated consequences that could have been anticipated).		
Economics			
	If oil price remains flat. "Concurrent Production" option becomes economically equivalent to the "Sequential Production" option if 11% of reserves are lost due to any of the above-mentioned multilateral well risk factors.	Risk factors better understood. Therefore, economics are more certain.	
If oil price declines. "Concurrent Production" option becomes economically equivalent to the "Sequential Production" option if 22% of reserves are lost due to any of the above-mentioned multilateral well risk factors.			

sure decline or, worse still, crossflow between laterals. If desired, the laterals can be isolated from one another by manipulating a sliding-sleeve ports or installing a tubing plug (see Fig. 5). However, if it becomes necessary to produce the laterals separately, then the full economic benefit of the multilateral well is no longer realized. In that case, the extra money spent to install a multilateral well yields no additional benefit beyond the simpler and less-risky Sequential Production scenario (i.e., two standalone horizontal wells produced sequentially).

During these decision-making sessions, though, the discussions concerning the impact of commingled flow were purely conceptual because the simulations to quantify the impacts of commingling had not yet been completed. To account for such a large unknown, multiple economic scenarios were simulated to understand the impact of varying levels of risked reserves (more on this topic in the Economics section below).

Technology and Implementation. Discussion in this category dealt primarily with the incremental equipment and procedures necessary for running and retrieving a whipstock for milling the upper-lateral window. Although many options were considered for how to create a TAML Level-2 junction and isolate the water zones that might be exposed between the junction and the horizontal portion of the lateral, the option deemed the least risky (i.e., the simplest) requires drilling the 8½ in. hole section through the 65-1 sand at an angle high enough to allow milling the whipstock window within the 65-1-sand boundaries. Thus, no water-isolation methods are needed between the window and the horizontal portion of the lateral.

It was definitely considered beneficial that TAML Level-2 junctions are so commonplace globally (≈1000 installed). However, a big concern was that they are not commonplace in Thailand. With such a short time remaining until spudding the well (3 weeks), there were concerns that obtaining qualified people for retrieving the whipstock might be a problem (although the local whipstock supplier was confident). The process of running whipstocks and milling windows was of little concern to Chevron. However, pulling a retrievable whipstock without leaving junk in the hole was our greatest concern at this stage of the project.

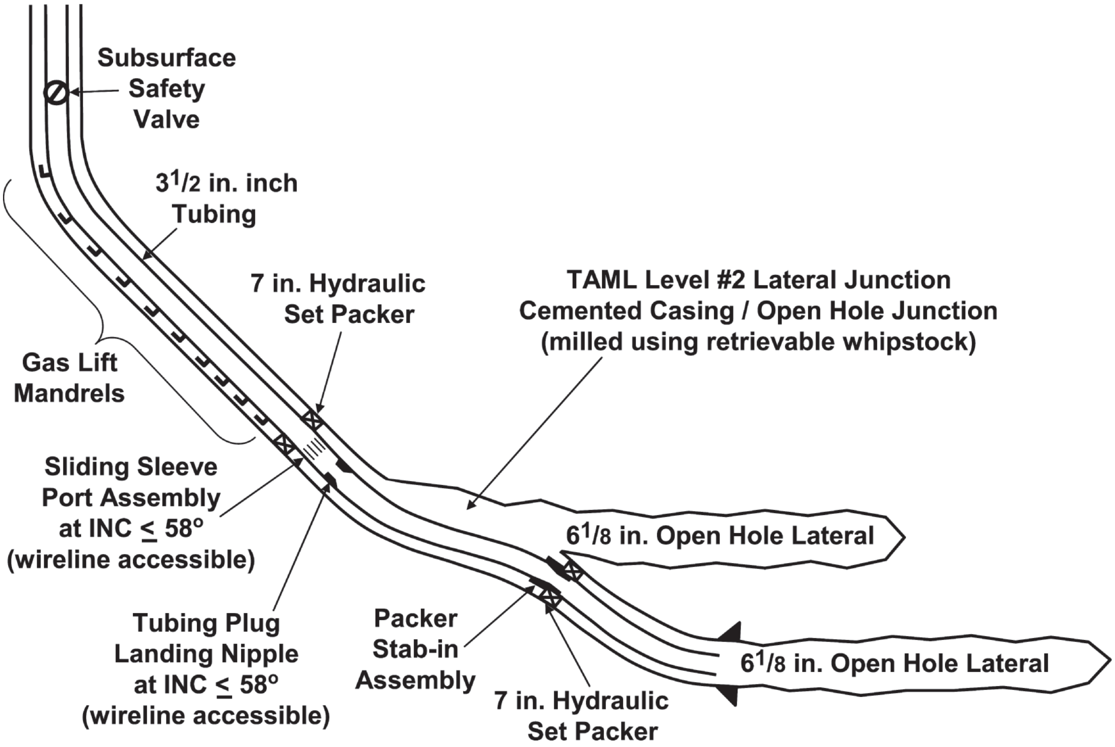

Fig. 5—Schematic of originally planned well with completion equipment installed.

Economics. The Concurrent and Sequential production scenarios, and their required investments, were each simulated with two oil-price forecasts, one with declining prices (the official forecast at that time), and a second with flat prices (some on the team considerered this more realistic). The producing life of each lateral is only 3 years. To compare the two production scenarios at the different price forecasts, we determined the amount of reserves that would have to be lost in executing the higher-risk, but more-profitable, Concurrent production scenario for it to be economically equivalent to the less-risky and less-profitable Sequential production scenario. The results are as follows: Assuming a declining oil price, the Concurrent Production scenario must lose 22% of reserves (because of all risks combined) for it to become economically equivalent to the lower-risk Sequential Production scenario. If a flat oil price is assumed, only an 11% reserves loss is necessary for economic equivalency to occur. The project team was unanimous that losing 22% of reserves is not a likely outcome from drilling the multilateral well. The probability of losing 11% of the reserves was the subject of more debate, indicative of less team alignment. At this point, the issue would have to remain unresolved because the simulations quantifying the impact of commingled production were not yet completed.

At the end of this series of team discussions and project evaluations, the team was able to agree that the risks of implementing slightly new technology in a short time frame (3 weeks from this point) were probably outweighed by the possible benefits of a large initial boost in oil production and the intangible psychological benefits of infusing a new drilling technique into an engineering environment where repetitive batch implementation of the same well design, although very beneficial from a business-efficiency perspective, can sometimes be a hindrance to creative thought. Thus, with 3 weeks remaining before spudding, the multilateral-drilling option was sanctioned and alignment of all team members was obtained.

In hindsight, there were two items noticeably absent from the above series of discussions. First, there was very little in-depth discussion concerning the possible difficulties of directionally drilling the 8½-in.-hole section (i.e., the portion of the well drilled to a horizontal orientation in the pay interval before installing 7-in. casing). The limited discussion that did occur consisted only of brief references to past successes in drilling similar 8½-in. hole sections in standalone horizontal wells. Other discussions with our directional-drilling service provider were of a similar nature. The fact that our past record in drilling this type of hole section was flawless (seven successes out of seven attempts) led to no critical comparison of this project's 8½-in. hole directional plan to that of its seven horizontal predecessors. It should be noted, however, that a detailed-risk assessment was performed on this project independent of the decision-making discussions described here. The issue of excessive torque and drag forces in the 8½-in. hole section was identified and addressed adequately by way of this risk-assessment process. Unfortunately, though, the directional-drilling capabilities of the bottomhole assembly (BHA) were not addressed in the risk assessment—again, a fact probably owing to the successful drilling of the previous seven 8½-in. hole sections. Second, there was no discussion of the possible existence of a gas cap in either the 65-1 or 69-1 sands, even though gas caps have been a common issue to contend with in other Gulf of Thailand horizontal-well projects. Although all fluid-identification work indicated only oil and water to be present, there was never any discussion as to what might lay above our shallowest known information. It was discovered later, after the multilateral well had been drilled, that the Geology, Geophysical, and Reservoir Engineering members of the project team did indeed know of the possibility of encountering a gas cap. The topic, however, was never established as a risk to be addressed during discussions with the entire project team; thus, the Drilling and Completions Engineering members of the team were unaware of the risk during the planning and execution phases of the project.

Approximately 2 weeks after sanctioning of the multilateral-well project, the commingled production simulations were completed. Assuming no difference in pore-pressure-decline rate between the 65-1 and 69-1 sands, the simulations indicate a loss of approximately 7% of reserves from the 65-1 sand not being produced because of the onset of water production from the lower lateral in the 69-1 sand. Some of the lost reserves, however, can be obtained by producing the 69-1 and 65-1 laterals separately, which at that point would be a reversion to the Sequential Production scenario. Finally, if the assumption of our commingled-flow simulations actually holds true (and nothing else occurs during project execution that negatively impacts costs or reserves recovery), then pursuing the multilateral-well option does make economic sense.

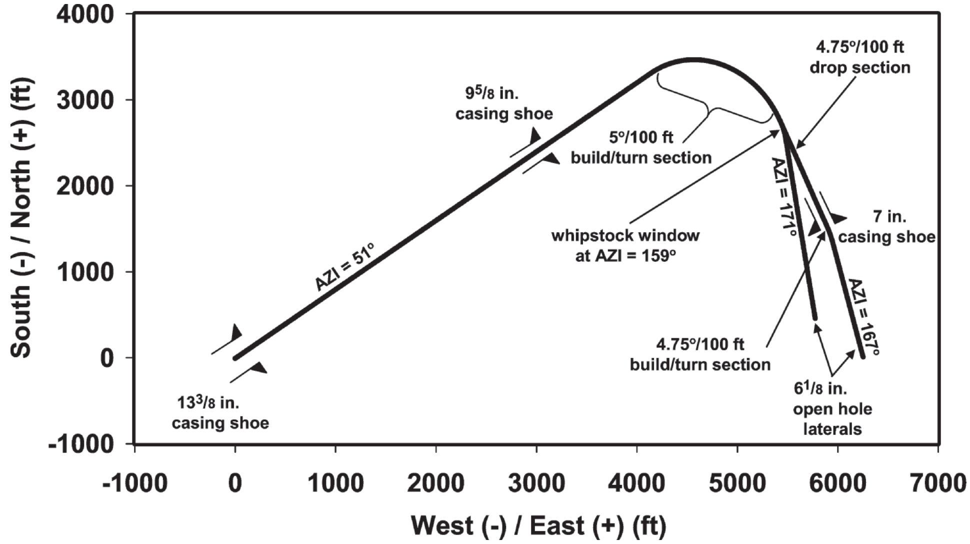

Fig. 6—Plan view of originally planned multilateral well.

Multilateral-Well Architecture and Predrilling Planning

Figs. 5, through 7 show the KPWD-30H (the multilateral well being discussed) well plans. The design for the well is not very different from a traditional standalone horizontal well as previously described in the Traditional Horizontal-Well Design section. The departure from tradition starts when drilling the 8½ in. hole section. Instead of drilling to a horizontal orientation by executing a single turn/build directional section, the planned 8½ in. section of KPWD-30H is composed of three directional sections before finally attaining a horizontal orientation in the 69-1 sand. The directional 8½-in. sections, in the order drilled, are:

- A 1,950-ft-long 5°/100-ft turn/build section with an INC change of 27° and a total AZI change of 108°
  - At start of section, INC = 53° and AZI = 51°
  - At end of section, INC = 80° and AZI = 159°
- A 360-ft-long 4.75°/100-ft drop section with a INC change of 17°.
  - At start of section, INC = 80° and AZI = 159°
  - At end of section, INC = 63° and AZI = 159°
- A 570-ft-long 4.75°/100-ft build section with a INC change of 27°
  - At start of section, INC = 63° and AZI = 159°
  - At end of section, INC = 90° and AZI = 159°

In total, 2,880 ft of directional drilling is performed in this hole section (a significant amount). At the time, this method of drilling was preferred because it minimizes the amount of directional changes required while drilling the 6⅛-in. laterals. This plan allows the whipstock to be set at INC = 80° and AZI = 159° within the boundaries of the 65-1 sand. Thus, the final 10° of INC change and 12° of AZI change to attain complete alignment of the upper lateral can be accomplished quite easily with a DLS = 5°/100 ft. Similarly, the 7-in. casing shoe is oriented such that only an 8° change in AZI is necessary to be fully aligned for extending the lower lateral into the 69-1 sand. The drilling fluid for drilling the 8½-in.-hole section and each 6⅛-in. lateral is identical to that of the previously-detailed standalone horizontal well design (i.e., SPDF and $CaCO_3$-laden SPDF, respectively).

After first drilling the lower 6⅛-in. lateral in the 69-1 sand the first section of completion equipment is installed. A 7 in. hydraulic packer with a 3½-in. tubing tail below is installed. The packer/tail assembly is spaced out so that the tubing tail is near the 7-in. casing shoe and the packer is positioned below the intended 7-in. casing-exit point for drilling the upper lateral in the 65-1 sand (see Fig. 5). The intent is to use the 7-in. hydraulic packer as the base on which the retrievable whipstock assembly is set. The whipstock is a single-trip setting/milling system that can be retrieved with a hook system that engages a slot on the face of the whipstock. Additionally, an overshot fishing assembly can be used to retrieve the whipstock if necessary.

After drilling of the upper lateral is accomplished and the whipstock retrieved, the rest of the completion equipment is installed as shown in Fig. 5. The sliding-sleeve port assembly and tubing-plug landing nipple are positioned below the upper hydraulic packer at an INC less than or equal to 58° to ensure they are wireline-accessible. These two wireline-manipulated components allow each lateral to be produced independently of the other if desired. Independently producing each lateral initially is necessary to establish their standalone production performance before commingling the flow streams.

Drilling Execution

The KPWD-30H was spudded on 9 March 2006. Drilling of the 15¾-in. surface hole and cementing of its 13⅜-in. casing (see **Figs. 6 and 7**) occurred without incident. Similarly, drilling of the 12¼-in. intermediate hole section and cementing of its 9⅝-in. casing were also without incident. Drilling of the 8½-in. hole section and subsequent operations, however, were not without problems.

Drilling 8½-in. Intermediate Hole. Drilling of this hole section was intended to be completed in a single run using a 7-in. steerable BHA equipped with a 1.4°-bend mud motor, a low-torque four-bladed PDC bit and LWD tools. Drilling of the initial tangent-hole section (INC = 53°) occured without problems. Unfortunately, only 500 ft of the planned 1,950-ft-long 5°/100-ft turn/build section below the tangent was drilled before the mud motor failed. To this point, directional performance was reasonably good, with INC being on target and AZI being only 3° behind target. Therefore, the next BHA was an exact copy of the first. An additional 1,124 ft of the planned turn/build section was drilled, but with unacceptable-directional results. The hole was now 8° behind the INC target and 3° behind the AZI target. At this point, the well had to be plugged back with cement to allow a reattempt at drilling this hole section along the initially planned path. The second attempt at correctly drilling this hole section ended quickly when the mud motor came apart after drilling 725 ft, leaving its bottom half in the hole. This precipitated a second cement plug back to allow sidetracking the hole around the obstruction.

After the second plug back, drilling once again commenced in earnest using the same BHA as above, but with a 1.76°-bend mud motor to allow better directional control to account for the directional sluggishness of the previous BHA. With this BHA, directional difficulties continued to bedevil drilling operations by way of sluggish directional response. As shown in **Figs. 8 and 9,** the whipstock-setting point for milling the upper-lateral window was neither at target INC (actual INC = 77° vs. target INC = 80°) nor at

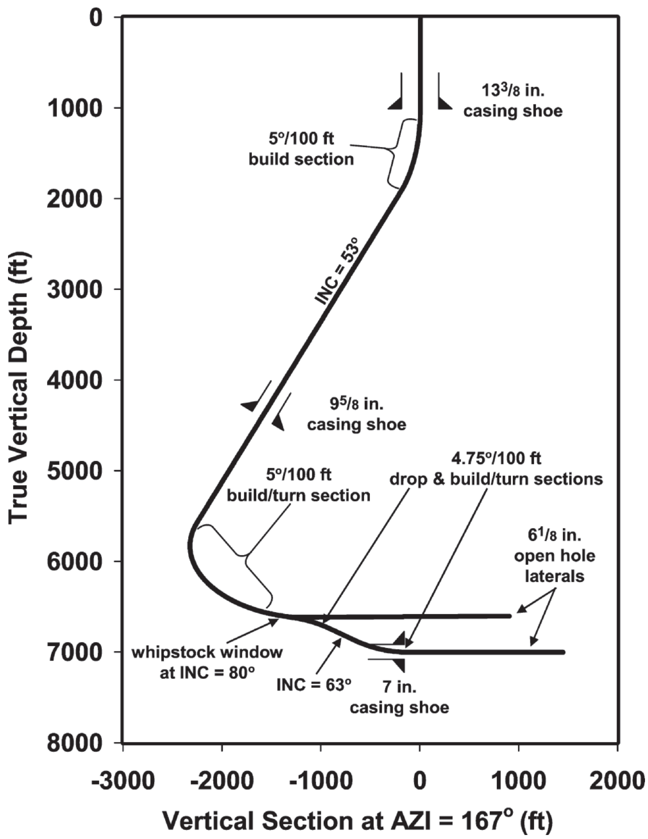

Fig. 7—Section view of originally planned multilateral well.

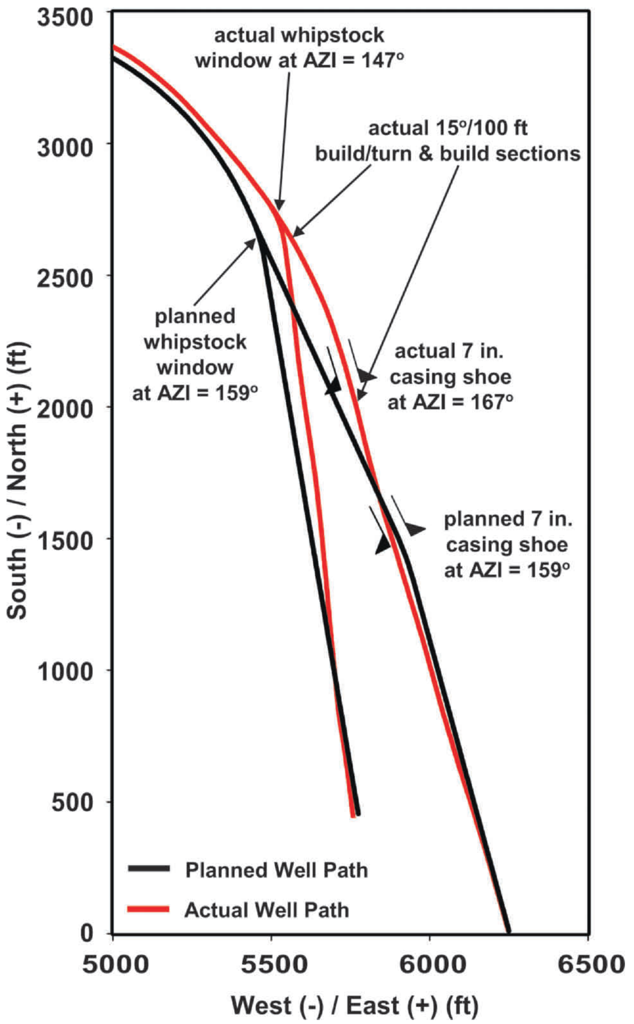

Fig. 8—Zoomed-in plan view of actual and planned well paths.

target AZI (actual AZI = 147° vs. target AZI = 159°). Similarly, it was not possible to attain a horizontal orientation at the correct vertical depth in the lower lateral's 69-1 sand. As a result, the 7-in. casing shoe was set just below the top of the 69-1 sand at INC = 71°. Luckily, the 7-in. casing shoe was correctly aligned AZIally, thus no turning would be necessary (only INC building) when attempting to drill the lower lateral.

Two dangers were introduced by the less-than-optimal path of the 8½-in.-hole that resulted from such sluggish directional control. First, the orientation of the 7-in. casing shoe dictates that a DLS = 15°/100 ft is necessary to build INC fast enough to hit the lateral targets of the 69-1 sand. Second, the sluggishness of directional control also resulted in the upper-lateral junction being positioned 60 ft closer to the trapping fault than originally planned (original plan being 100 ft away from the fault). This is an uncomfortable predicament considering that the exact position of the fault is not known. Like the 69-1 lateral, the drilling of the 65-1 lateral will also require a DLS = 15°/100 ft to turn fast enough to avoid crossing the trapping fault. Luckily, the INC of the intended junction is only 3° less than planned; thus, building INC at the start of the upper lateral is not as critical as making a rapid turn to miss crossing the fault.

Although initially quite surprised by the lack of directional control while drilling the 8½-in. hole section, in hindsight it is reasonable to conclude that we should not have been so surprised. **Table 2** shows a compilation of the directional drilling parameters that are indicative of directional control difficulty. The data shown cover all previous 8½-in. hole sections drilled in horizontal well projects and also that of the present multilateral-well project (i.e., KPWD-30H). The parameters that indicate the expected difficulty of directionally drilling a hole are the TVD depth of the hole section, the DLS of the hole section, and the length of the hole section. Using a reasonable scoring guide for each parameter (shown in Table 2), the difficulty scores for the parameters of each well are determined. The total directional difficulty score for each well is the sum of the individual-parameter scores. When objectively compared in this way, it becomes obvious that the directional plan for drilling the 8½-in. hole section in KPWD-30H was the most difficult attempted thus far. This fact, however, was not on the collective mind of the project team during the process of decision making and planning. Thus, no backup plans were formulated to address the possibility of poor directional control. As discussed below, this and other factors will later combine to create a few unintended consequences.

Drilling 6⅛-in. Lower Lateral (69-1 sand). It was initially planned to drill the lower lateral in a single run. This, however, proved to be impossible because of the 7-in.-casing shoe being set at the top of the 69-1 sand at INC = 71°. To account for this difficulty, the lateral was drilled in two sections. The first section was drilled from the casing shoe to a horizontal orientation at a DLS = 15°/100 ft using a 4¾-in. steerable BHA equipped with a 1.76°-bend mud motor, a tri-cone rock bit, and MWD tools. No LWD tools were run to allowing placing the MWD tool as close to the bit as possible in this directionally critical section of the hole. The tricone rock bit was used in this high-DLS hole section to minimize the torque generated by the bit, which, in turn, allowed better control of the BHA's toolface in this very critical section of the well. After successfully attaining a horizontal orientation, a 4¾-in. steerable BHA equipped with a 1.22°-bend mud motor, a low-torque 4-bladed PDC bit and LWD tools was used to extend the lateral to its planned TD.

Figs. 8 and 9 show the planned and actual position of the 7-in. casing shoe. An unintended (but beneficial) consequence of the poor-directional control while drilling the 8½-in. hole section is the position of the 7-in. casing shoe. It allowed an extra 400 ft of lateral length to be drilled, to attain a total length of 2,000 ft

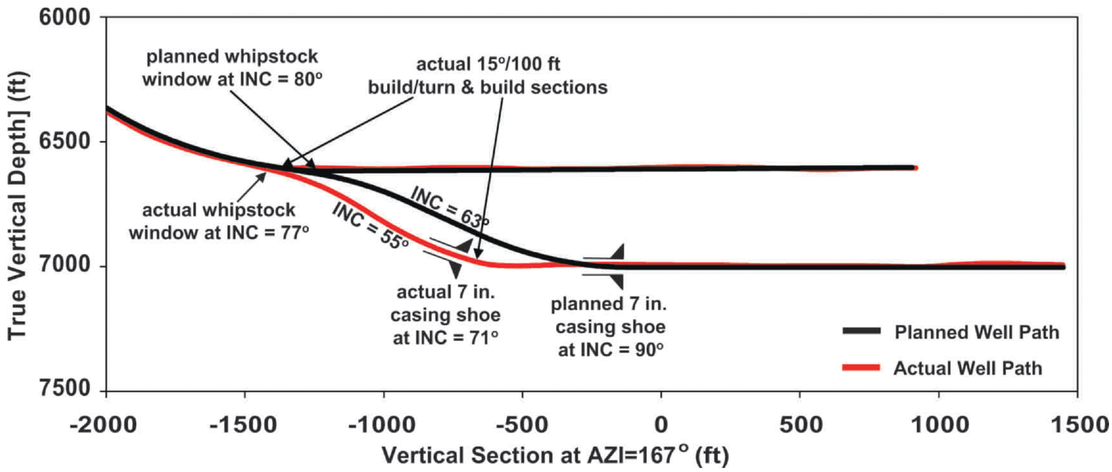

Fig. 9—Zoomed-in section view of actual and planned well paths.

(compared to the original plan to drill only a 1,600-ft lateral). However, obtaining the extra 400 ft of lateral length did come at a cost. Attempting to obtain the extra lateral length made it more difficult to land the 8½-in. hole section horizontally which, combined with the sluggish directional behavior of the BHA, resulted in the less-desirable outcome of the 7-in. casing shoe being set at INC = 71° rather than horizontally (as discussed in the previous section).

Fig. 10 shows in more detail the actual position of the lateral relative to its planned position. Although placed an average of 10 ft TVD higher than the planned lateral, the position was thought to be acceptable from a reservoir-management perspective, considering that there was no evidence of a gas cap in any of the offset wells. However, while extending the lateral it was soon recognized that more gas was present in the 69-1 sand than anticipated. Ultimately, it was identified that the 69-1 did indeed possess a large gas cap and that the lateral was drilled along the gas/oil contact. Here, the poor-directional control while drilling the 8½-in. hole section has resulted in an unintended consequence. Had there been better directional control in the 8½-in. hole section, it would have penetrated 100-200 ft MD of the gas cap while drilling to a horizontal orientation, rather than terminating just below the top of the 69-1 sand that made identifying the gas cap impossible. In this scenario, the gas cap would have been identified before installing the 7-in. casing and steps to position the lateral below the gas/oil contact could have been taken. It is, however, interesting to note that none of this train of thought was on the mind of any project team member because the presence of a large gas cap was never considered a possibility. Gas caps, however, had been encountered in other previous horizontal well projects in neighboring platforms. In this particular case, the gas/oil contact was found to be at 6,996 ft TVD, which is, ironically, 1 ft VD above where the KPWD-11

TABLE 2—COMPARISON OF DIRECTIONAL DRILLING DIFFICULTY FOR 8½-in. TURN/BUILD HOLE SECTIONS OF HORIZONTAL WELLS DRILLED BY CHEVRON IN THE GULF OF THAILAND. THE 8½-in. HOLE SECTIONS LISTED ALL TERMINATE IN A HORIZONTAL ORIENTATION IN THE INTENDED PRODUCING INTERVAL

Well Name	Bottom of Turn/Build Section (TVD)		Dogleg Severity of Turn/Build Section (°/100 ft)		Length of Turn/Build Section (MD)		Directional Drilling Difficulty Ranking of Turn/Build Section	
	Value	Score	Value	Score	Value	Score	Ranking	Total Score
PMWC-28H	3900	2	5	3	1400	1	5	6
PLWG-21H	3800	2	5	3	1000	1	5	6
PMWG-01H	3700	2	6	4	1100	1	4	7
YAWC-07H	6600	4	4	2	1500	2	3	8
PMWB-04H	6300	4	3.5	1	2900	4	2	9
PMWH-30H	6500	4	3.5	1	2700	4	2	9
PMWG-30H	4000	3	6	4	1800	2	2	9
KPWD-30H	7000	4	5	3	2900	4	1	11

SCORING GUIDE (TVD)	SCORING GUIDE (Dogleg Severity)	SCORING GUIDE (MD)
1000-1999 ft TVD = 1	3.0-3.9 °/100 ft = 1	1000-1499 ft MD = 1
2000-3999 ft TVD = 2	4.0-4.9 °/100 ft = 2	1500-1999 ft MD = 2
4000-5999 ft TVD = 3	5.0-5.9 °/100 ft = 3	2000-2499 ft MD = 3
6000-7999 ft TVD = 4	6.0-6.9 °/100 ft = 4	2500-2999 ft MD = 4
(4 = Most Difficult)	*(4 = Most Difficult)*	*(4 = Most Difficult)*

Most Difficult 8½ in. Turn/Build Hole Section Of All Horizontal Wells Drilled By Chevron In The Gulf Of Thailand

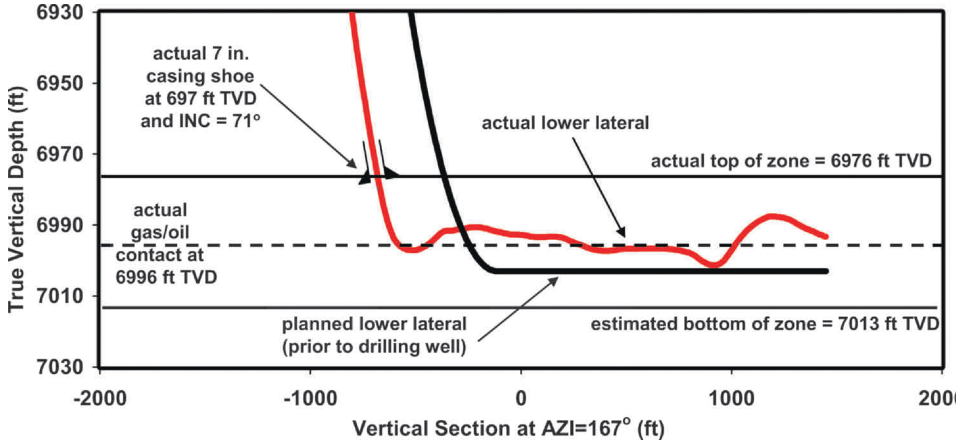

Fig. 10—Vertically accentuated (20-to-1) section view of actual and planned lower lateral placements in the 69-1 Zone.

penetrated this sand (i.e., the shallowest penetration of all offset wells before drilling the KPWD-30H multilateral well).

Drilling 6⅛-in. Upper Lateral (65-1 Sand). Before the start of whipstock operations, the openhole logs were evaluated to confirm the measured depth distance from the nearest water sands to both the top and bottom of the planned whipstock window. This was done to evaluate the risk of water entry from extraneous zones once the well is producing. The nearest water zones are 57 ft MD above and 236 ft MD below the whipstock window, with the upper water zone being only 5 ft VD thick and discontinuous between offset wells. That, coupled with the fact that the window is only 903 ft MD from the 7-in.-casing shoe (resulting in at least 85% of the casing cement volume passing the window during the cement job), led us to conclude that a cement-bond log was not necessary near the window interval to ensure isolation from extraneous water sources.

The setting of the whipstock and subsequent milling of the window were uneventful, with the exception that two mill runs were necessary to complete the window-milling process.

Unlike the lower lateral in the 69-1 sand, the upper lateral was intended from the beginning to be drilled with two BHAs because of the previously discussed turn necessary to avoid crossing the trapping fault. The DLS requirement of the original plan was only 5°/100 ft. The poor AZIal alignment of the window during implementation, however, increased that requirement to a DLS = 15°/100 ft to accomplish the turn without crossing the fault. The same two BHA configurations used to drill the 69-1 lateral where used to successfully drill the 65-1 lateral, considering that their directional requirements were the same. There was no evidence that the trapping fault was crossed while drilling the 23° turn section of the upper lateral.

Fig. 11 shows in more detail the actual position of the lateral relative to its planned position. There was no indication of a gas cap when the 8½-in. hole section first penetrated this sand. While drilling the lateral, lowgas trends in the returning drilled rock and LWD data indicated no evidence of drilling in a gas-saturated environment anywhere along the lateral. The lateral was drilled to its TD without incident other than a single MWD tool failure.

Whipstock Retrieval. Retrieving of the whipstock (or, actually, attempts at retrieving the whipstock) exposed a risk that the team did originally anticipate and attempt to address during the planning stages of the project. What is referred to is the risk that "obtaining qualified people for retrieving the whipstock might be a problem." This risk was pointed out previously in the Technology and Implementation section. After much planning-phase discussion with the local whipstock supplier concerning the need for an on-site service professional with retrievable-whipstock experience, the end result was the arrival of an onsite service professional that had never retrieved a whipstock. The consequence of this foreseen, but still inadequately addressed, risk was the use of incorrect tools to attempt pulling the whipstock by the inexperienced on-site service professional, resulting in multiple failed attempts to retrieve the whipstock. To be more specific, the hook retrieving tool previously mentioned in the Multi-Lateral-Well Architecture and Pre-Drilling Planning, was incorrectly configured to latch the whipstock. For this specific supplier, the correct hook configuration has a bend at the hook's end that ensures engagement of the hook in the retrieving slot on the face of the whipstock. The actual hook brought to the wellsite had no such bend–a subtle difference in tool configuration that only an experienced service person would have noticed. After schematics of the correct configuration where sent to the rig, only then was the problem identified and fixed by

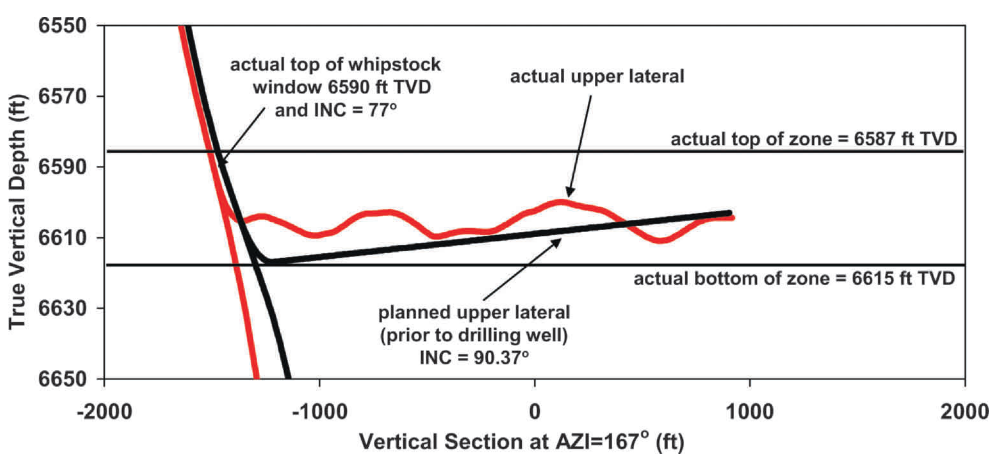

Fig. 11—Vertically accentuated (20-to-1) section view of actual and planned upper lateral placements in the 65-1 Zone.

making an onsite modification to the hook. The whipstock was pulled without incident on the first run with this corrected hook configuration.

Completion Equipment. The rest of the completion equipment was installed in the well with little difficulty, except for some temporary difficulty setting the upper packer.

Time Summary. In total, 29 rig days were required to drill and complete this well, compared with an original plan of 12 days. Thus, an additional 17 days were necessary to complete this project (142% more than expected). So, what necessitated did these additional 17 days of work? The major contributors are as follows:

• ***Drilling 81.2-in. Intermediate Hole–8 additional days.***

The primary contributors are:

a. *½ day* because of a premature mud motor failure.

b. *2½ days* because of plugging back the well with cement and redrilling as a result of sluggish directional response from the 7-in.-steerable BHA.

c. *2½ days* because of plugging back the well with cement and sidetracking the well around a mud motor lost in the hole.

d. *2 days* because of slow drilling rates while struggling with poor directional BHA control.

Drilling 6⅛-in. Lower Lateral (69-1 Sand)–2½ Additional Days.

The contributors are:

e. *1 day* to drill out the 7-in. casing shoe using a rotary BHA to avoid damaging the high-DLS BHA used to drill from the casing shoe to horizontal—a negative consequence of not being able to land the 7-in.-casing shoe horizontally.

f. *1 day* to drill from the 7-in. casing shoe to horizontal using a high-DLS BHA—a negative consequence of not being able to land the 7 in.-casing shoe horizontally.

g. *½ day* to drill an additional 400 ft of horizontal hole because of the actual placement of the 7-in. casing—a beneficial consequence of poor directional BHA control in the 8½-in. hole section.

(2) ***Whipstock Operations and Drilling 6⅛ in. Upper Lateral (65-1 Sand)–4 Additional Days.***

The contributors are:

a. *1½ days* slow milling of the window and the need to run two mills rather than the anticipated one mill.

b. *1½ days* because of an MWD failure while drilling the lateral.

c. *1 day* because of the aforementioned problem with retrieving the whipstock.

From this list of wasted time (excluding, of course, the ½ day spent drilling the extra 400 ft of the lower lateral) it is easy to deduce that 7 days of lost rig time are attributable (directly and indirectly) to the poor directional control experienced while drilling the 8½-in. hole section. Additionally, 4½ days were wasted because of mud motor and MWD tool failures and 2½ days were wasted during whipstock operations. On the basis of the previous discussions in this paper dealing with the foreseeability of the drilling difficulties encountered in the 8½-in. hole section and that of whipstock operational problems, it is reasonable to conjecture that 8 days of the 17 total days of wasted time might have been avoided during the execution of this project.

Post-Drilling Production Operations and Well Performance

First production from this well came from the lower lateral in the 69-1 sand. Becuase the sliding-sleeve port assembly was already closed to allow the setting of the upper-hydraulic packer, it was reasonable, and simplest to proceed with testing that lower lateral first. Recall that this lateral was unintentionally drilled along the gas/oil contact (see Fig. 10). As expected, on the basis of such an unfavorable lateral position, initial production from the 69-1 was dominated by gas (5 to 10 MMscf/day) with some accompanying oil (300 to 600 B/D). The lower lateral was produced in this mode for 2½ weeks. Interestingly, though a little unsettling, small amounts of water were showing up in the production within 2 days of first production. The early water production was noticed in a manual fluid shake out test (1.5% of total liquids) and did not register on the well tester (a tester later diagnosed with water-measurement problems). Considering that the lateral is 45 ft VD above the OWC, having any water production this early was certainly unexpected.

After the initial 2½ weeks of solely producing the 69-1 lateral, both laterals were then produced commingled and have continued in this fashion to the time of writing this paper (3 months later). The results are not promising. Shortly after commingling began (within 1 week), water production grew to 3 to 5% of total liquids. In the next 7 weeks, water production from the commingled flow stream continued to grow to 60 to 80% of total liquids, with periodic respites into the 30 to 40% range.

Production logging was performed at the end of this period and found that each lateral was equally contributing to the total water production. Again, the water production issue is perplexing. Like the lower lateral, the upper lateral sits 40 to 60 ft VD above the OWC. It seems highly unlikely, if not impossible, that coning is the culprit. Additionally, extraneous water production is thought to be unlikely both for the lower lateral (on the basis of 7-in. casing shoe being cemented in the 69-1 producing zone) and the upper lateral (on the basis of the previous discussion of the window's placement relative to water zones and its nearness to the 7-in. casing shoe–which enhances cement bond). Other alternatives conjectured amongst the project team are the possibilities of water encroachment along thin, more preferential flow units within the 65-1 and 69-1 sands or the possibility of water movement along a nonsealing fault.

Another finding from the production logging investigation is that crossflow can occur between the two laterals. By flowing the commingled production at different rates it was determined that a dynamic balance point exists. A production rate above the balance point (which sufficiently lowers bottomhole producing pressure) allows both laterals to contribute flow. Conversely, a production rate below the balance point raises the flowing bottomhole pressure and induces crossflow from the upper lateral to the lower one. The balance point at which crossflow occurs is certain to change during the life of the well as pressure regimes in the 65-1 and 69-1 sands change with time. The possibility of crossflow at such an early phase in the well's life is, however, an unwelcome outcome, as previously discussed in Reserves Recovery.

At the time of writing (mid-August 2006), commingled oil production from KPWD-30H was 50 to 100 bbls/day as a result of high water cuts. The expected initial oil rate at which the project was justified was 4,200 bbls/day. Future production of this well will use gas lift to maximize fluid rates. The outlook, however, is not optimistic because of the unusually high water production exhibited thus far.

Conclusions/Lessons Learned

Although the well was successfully drilled and completed, the project cannot be considered an economic success given the low oil rates, high water cuts and crossflow tendencies the well exhibits, combined with the significant cost overruns incurred during its drilling. Some of the items contributing to this outcome may have been preventable, and, conversely, some were not. Accurately determining what is and is not preventable, and why, is the key to capturing lessons learned and conclusions that provide significant value to others.

Conclusions.

- Discussions in the planning phase of the project were, on the whole, focused more on Drilling's ability to quickly formulate and execute a drilling and completion plan than on the subtleties of what we did not know about drilling and operating a multilateral well.
- Although the possibility of encountering a gas cap was understood by the Geology, Geophysics, and Reservoir Engineering members of the project team, that fact was never revealed during discussions amongst the entire project team. This resulted in the Drilling and Completions Engineering members of the team not

understanding that encountering a gas cap was a real possibility. The lack of a "gas cap" discussion during project planning lead to there being no contingency planning in the event a gas cap was discovered.
- Commingled production concerns were identified during project planning, but the discussion revolved more around premature watering out of a single lateral than around crossflow. Simplified-commingled production simulations (assuming no pressure decline difference between the laterals) were completed prior to spudding the well. However, there were no simulations performed to understand the possible impacts of disparate pore pressure decline rates. Furthermore, there was not enough time to leverage multilateral production-operation experience elsewhere within the Chevron organization to understand just how sensitive a well like this might be to the occurrence of crossflow between producing laterals.
- A detailed risk assessment was performed on this project and accurately identified and addressed the possible risk of excessive torque and drag forces because of the directional tortuosity of the 8½-in.-hole section. Discussions concerning 8½-in. hole directional drillability were not, however, of sufficient depth to identify that the KPWD-30H's 8½-in. hole section would be the most difficult one yet attempted in the Gulf of Thailand. Consequently, no contingency plans where constructed to address scenarios that might arise as a result of poor directional control.
- The poor directional control of the 8½-in. hole section combined with the unanticipated existence the large gas cap in the 69-1 sand resulted in various knock-on effects, such as:
  - The lost opportunity to identify the existence of the 69-1 gas cap while drilling the 8½-in. hole section.
  - The lost opportunity to drill the 69-1 lateral differently so as to better avoid producing from the gas cap.
  - The need to run extra BHA's to drill the 69-1 lateral–BHA's that would have been unnecessary had better 8½-in. hole directional control been possible.
  - The need to perform difficult cement plug backs of the 8½-in. hole in a cement-unfriendly synthetic paraffin drilling fluid.
  - Inordinately slow 8½-in. hole drilling rates to account for the directional sluggishness experienced with all BHA's in this hole section.
- Although whipstock predrilling engineering and operational-planning support was sufficient for this project, the experience level of onsite personnel during the execution phase was not. Approximately 1½ days of rig time was wasted because of this. Even though the upper-lateral window was successfully milled and the whipstock eventually retrieved, the lack of adequate onsite experience could have resulted in much more wasted rig-time or, worse, the whipstock not being retrieved and the ultimate loss of the lower lateral.

Lessons Learned.

- The shortness of time between the confirmation of the 65-1 and 69-1 sands as horizontal wellbore targets and the actual spudding of the multilateral well (only 5 weeks) probably played a role in the chemistry of the various project team discussions. During project-sanction discussions, the shortness of time to plan and execute this project was always on the minds of the project team members. As alluded to in the Conclusions section, many discussions focused on the ability to formulate and execute a drilling plan in the short time available rather than on rooting out the subtle differences between this multilateral well and our previous standalone horizontal wells. There is no indisputable causality between the shorter-than-normal decision and planning time of this project and missteps that occurred during the project sanctioning phase. It is still important, however, to note that time restrictions were an ever-present concern while struggling with the numerous technical issues associated with implementing this small step forward in technology.
- The shortness of time between project sanctioning and actual spudding of the multilateral well (only 3 weeks) resulted in there being only enough time to confirm the availability of the equipment needed for drilling and completing the well, to confirm the correct running procedures for any new-to-Thailand equipment used in this project, and to generate and quality review a complete well-site drilling program package. Thus, from a drilling engineering perspective, there was insufficient time available for addressing the relevant issues discussed in Conclusions above (assuming those issues would have been uncovered in the first place during the project sanctioning phase).
- The importance of in-depth contingency planning for any project in which new technology is being introduced cannot be overstated. As presented in Conclusions, a single-unanticipated event (like 8½-in. hole directional problems) can breed numerous other problems during the execution phase of a project.
- The implementation of new technology, especially in a geographic region that is slightly remote, certainly requires that highly experienced service company personnel be on site. Sufficient time (more than in the main stream hydrocarbon producing regions) must be allocated to ensure that all the necessary field-based experience is well-coordinated and prepared. In the case of the KPWD-30H multilateral well, sufficient time was invested for this purpose. Unfortunately, a lack of coordination of whipstock-service personnel still resulted in an inexperienced service hand providing rig-site support for this project.
- The so-called simplicity of drilling and producing a TAML Level 2 multilateral well probably played a significant role with project team members being able to become inadvisably comfortable with tackling this project in the face of so many unquantified risks, with some of those risks remaining unquantified by choice (e.g., crossflow potential) and others by oversight (e.g., 8½-in. hole directional-drilling difficulty and gas cap existence). Implementing a new technology is exciting and, therefore, desirable to work on. However, the allure of new technology can, under certain circumstances, have a biasing effect during the decision making process. If the technology step is a large one, it will usually heighten the risk awareness of all project contributors to the point that few, if any, details are left unaddressed (a good outcome). However, if the technology step is perceived to be a small one, it is easier for project contributors to become less risk aware concerning all aspects of a project and to focus more on the specific risks associated with only the small step change itself (a not-so-good outcome). In the case of the KPWD-30H multilateral well, most of our attention dealt with correctly setting and retrieving the whipstock, with many other aspects of the well receiving less attention because they were perceived to be similar to what had worked on other previously drilled stand alone horizontal wells–a perception that proved to be incorrect in some of the aforementioned cases.

In summary, even a seemingly simple step forward in technology application can be fraught with numerous new and unanticipated problems to be solved. The two most important keys to preparing for such problems are appropriate risk awareness and appropriate time to plan accordingly. These are the two biggest lessons to be learned from the KPWD-30H multilateral project.

Acknowledgments

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SI Metric Conversion Factors

acre ×	4.046 856	E-01	= ha
bbl ×	1.589 991	E-01	= M^3
ft ×	3.048*	E-01	= M
°F	(°F-32)/1.8		= °C
gal ×	3.785 412	E-03	= M^3
lbm ×	4.535 924	E-01	= kg
md ×	9.869 233	E-04	= μm^2
psi ×	6.894 757	E+00	= kPa

*Conversion factor is exact.

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