Rotary Steerable Lateral Drilling System

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Introduction

Horizontal drilling has become widely accepted as a standard option for exploiting oil and gas resources. In many areas new wells are routinely completed as horizontal wells, with vertical completions becoming the exception rather than the rule. Even as horizontal completions have become common in some places, there are still many areas where they have failed to be economically effective.

There are two main industry thrusts underway for improving the economical success of horizontal wells. One is to develop a better understanding of where and how horizontals should be utilized and the other is to reduce the cost of installing the wells. This paper is primarily aimed at describing a lateral drilling system that can reduce the cost of installing laterals while at the same time improving the quality of the hole drilled.

Some horizontal wells are drilled as grass roots wells, while others are drilled as re-completions of existing wells. It would seem intuitive that utilizing an existing well would be cheaper than drilling a completely new well, but this was not true for many of the initial attempts at developing horizontal completions from existing wells. This resulted from the fact that slim hole, short radius drilling methods which benefited the most from the existing wellbores were very problem prone. Medium radius drilling techniques were less problem plagued, but they generally used larger tools and required much longer intervals above the pay zone to be re-drilled. This longer distance to be drilled, the requirement for extra casing strings, and the often less than optimum hole size caused the costs to increase to near that of a new well.

Re-entry drilling became more attractive as the short radius drilling methods using articulated mud motors became more effective.[1] Currently the re-entry market is quite active. Even so, there are still many places where the articulated motor short radius drilling methods are not cost effective. This provides the opportunity for using a less expensive rotary steerable lateral drilling technique.

The need for cost control has also fueled a general expansion of the use of slim hole drilling for development wells in many areas. In places where the production rates would benefit from a horizontal completion, these wells make excellent opportunities for lateral drilling, but the horizontal costs must be kept low in order to maintain acceptable economics. These wells also provide an good opportunity for using a less expensive rotary steerable lateral drilling technique.

Horizontal re-entry wells have proven to be very effective in offshore applications for rate acceleration while reducing gas/water coning, for use as a "straw" to reach reserves that are not readily accessible from the existing well bores, and to develop thin sands that did not provide adequate rates with vertical completions.[2,3] Currently many of these wells are being drilled with full size workover rigs, but there is considerable interest in being able to drill them with coiled tubing to reduce the mobilization costs. Another way of achieving almost the same mobility is to drill the wells with a long stroke snubbing unit and the rotary steerable lateral drilling system. While this concept does not provide the tripping speed of the coiled tubing, it does provide extra capability in terms of being able to rotate the pipe and is more efficient than coiled tubing for many operations.

Horizontal Well Prospect Selection

Horizontal drilling sometimes seems to be thought of as a magic cure for a low productive well. Thinking of it in this way is sure to lead to frustration, disappointment, and wasted resources. On the other hand properly selected candidate wells provide very attractive economic opportunities. Horizontal drilling should not be considered a last ditch effort to save a non-paying property, but rather as a very specific cure for certain ills. Horizontal wells can be used to increase the exposure to the reservoir, control water and gas coning, tap new drainage areas (lenses, fractures, attic oil), and optimize enhanced recovery processes.[4,5,6,7]

Horizontal wells can clearly expose more formation to the well bore than a similar vertical well. **Figure 1** shows model predictions that indicate that this additional exposure can lead to a several fold increase in production rates.[10] For example an easily obtainable 600 ft lateral in a 25 ft thick reservoir should produce at a rate about 3-1/2 times that of a vertically completed well. The average reported production gain from horizontal wells completed in formations that produce from matrix permeability is two to seven times that of a vertical well, but this result is sometimes not achieved.[8]

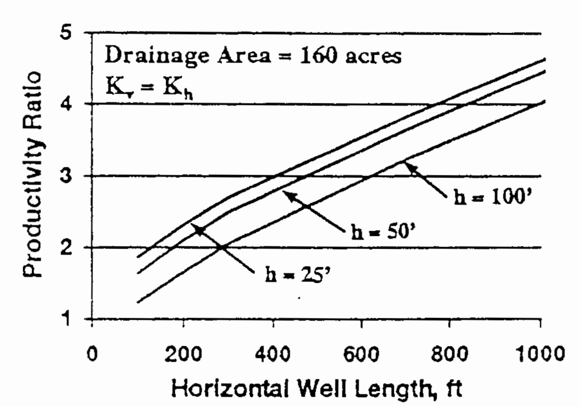

Figure 1: Production increase from horizontal well.

These predictions reveal both information that is helpful in selecting appropriate candidates and in avoiding inappropriate candidate wells. First the predictions represent the expectations for an un-stimulated reservoir that has equal vertical and horizontal permeability. Often this is not the case. If the permeability is low, the vertical wells are often fracture stimulated. This process may open up more exposure to the formation than drilling a lateral and may also reduce the effects of vertical permeability barriers. If the well is a low rate producer because of poor quality reservoir rock, then drilling a lateral may not be as likely to achieve the desired results as fracture stimulating the well. Even if the horizontal and vertical permeability are equal, but very low, and the horizontal well produces 3 times as much as the vertical, the production rate may still be too low to be economical. In other words, for tight reservoirs, simply obtaining additional reservoir exposure provided by a short radius lateral probably may not provide an adequate production increase.

On the other hand the simple model predictions indicate that a well that is a reasonable producer and not normally considered for stimulation, may respond nicely to the installation of a relatively short length lateral. If the reservoir rock quality is good and the well is a low producer because of low pressure then the well may also be a good candidate for a lateral re-completion.

Similar comments could be made about the other reasons for drilling lateral wellbores, but the main point is that a candidate should be chosen for a specific, well thought-out reason. When this is done, many wells are eliminated as candidates for lateral drilling, but the overall result is much more likely to be satisfying.

Assuming that an attractive candidate for a horizontal completion is identified, then there are a number of decisions that need to be made relative to planning the well, such as selecting the most cost effective drilling method that will be used. The remainder of this paper describes a recently commercialized slim hole lateral drilling technique that is attractive for some lateral drilling applications.

Slim Hole Rotary Drilling System

Most short radius lateral re-entry wells are currently drilled with articulated mud motor drilling systems. These systems have evolved into reasonably robust drilling tools in the last few years, but they are still relatively expensive and result in a well bore that is usually rather tortuous. The potential for providing a lower cost lateral drilling technique and one that potentially could lead to a better quality bore hole provided the incentive to develop the Amoco rotary steerable system.

The rotary steerable lateral drilling system does not use a mud motor at all, but rather relies on rotating the drill pipe to apply the drilling energy to the bit and utilizes a non-rotating eccentric sleeve to direct the bit, thus it is referred to as a "rotary steerable system". The system is specifically designed to be operated from a work-over type rig, to be able to drill laterals from wells with casing as small as 4-1/2", and to minimize the system costs by using less costly components. It can be used to drill curves with radii as short as 30 ft and to drill laterals that are typically 200 - 700 ft long. Multiple curves from the same vertical bore can be drilled.

The original objectives of the rotary steerable system were primarily to provide lower lateral drilling costs and to provide a smaller system than was available with mud motors. The commercially available rotary steerable system does provide a lower cost option than motors and it can be used through 4-1/2" casing, but there are some motor systems available now that can also be used through 4-1/2" casing. Often wells drilled with motor systems have undulating paths that can severely restrict hydrocarbon production.[9] One benefit of the rotary steerable system that was not fully anticipated is that the curves and laterals are much straighter than those drilled with motor systems. This is achieved at the expense of somewhat less directional control, but it may provide a definite advantage for completion and production.

The rotary steerable system eliminates the difficulty of sliding that often plagues mud motor systems while drilling in the oriented mode. Since the drill string is always rotated, it slides freely through the hole, simultaneously facilitates the cuttings removal, and may result in a significant increase in penetration rate over motor systems. The system can also be used with air or mist as the drilling fluid for low reservoir situations.

Overall Drilling System

The overall procedure for drilling a lateral with the rotary steerable drilling system is similar to that required for any other lateral drilling system as shown in Fig. 2. A target interval is selected based on the specific objectives of the well and the known reservoir information. The kick off point and radius of curvatures are selected to end the curved section at the point in the reservoir where the lateral is to be initiated. Considerations in selecting the radius of curvature include formation properties above the target zone, the type of flexible pipe that is to be used, casing conditions, length of desired lateral and thickness of the target zone. Curvatures ranging from 30 ft to greater than 100 ft can be selected. The lateral may be planed as a truly horizontal section, but is often planned to be inclined to traverse the target zone.

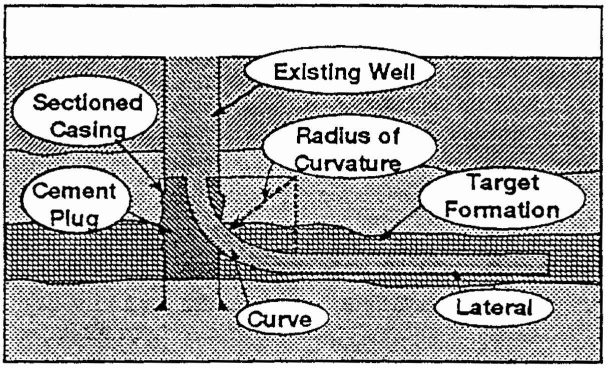

Figure 2: Lateral re-entry completion.

The curve is normally initiated from either a cement plug or the formation at the bottom of the well. The distance to be sectioned is generally about 20 to 30 ft for curvatures between 30 ft to 90 ft, with the sectioned interval extending about 5 - 10 ft above the kick-off point. Although there is no obvious reason why a whipstock can not be used instead of sectioning the casing, no experience is available with this method. The rotary steerable curve drilling tool appears to provide a more positive kickoff than motors, thus there has been little reason for investigating the use of whipstocks.

The major steps in a re-entry operation after the well is cleaned out and older completions abandoned are to 1) section the casing, 2) set the cement plug, 3) simultaneously dress the cement plug and drill a pilot hole, 4) drill and survey the curve, and 5) drill and survey the lateral.

Curve Drilling Tool

The curve drilling tool operates simply by keeping the bit pointed in the desired direction and utilizing a special bit that drills where its pointed. A non-rotating eccentric sleeve positioned near the bit is used to point the bit. As shown in Figure 3 the eccentric sleeve positions the up-hole end of the rotating mandrel off the center of the bore hole by a distance, e, and this in combination with the length of the mandrel determines the tilt of the bit with respect to a straight bore hole. When the bit drills in the direction that it is pointed, then the well path becomes a circular arc. The radius of the circular arc is simply determined as :

$$R = \frac{L^2}{24e} \quad \text{.................} \quad \text{Eq. (1)}$$

L = assembly length, in.
e = eccentricity, in.
R = radius of curvature, ft

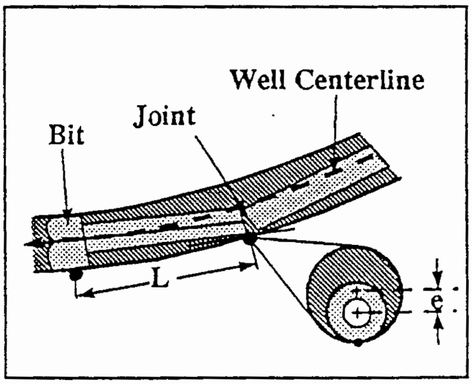

Figure 3: Concept for rotary steerable system.

The critical parameters that must be controlled i order to drill the desired curvature are that the hole must remain at the designed diameter, the b must remain in the center of the hole, and the top end of the mandrel must remain in the desired displaced position. In practice these requirements are meet by designing the drill bit specifically to drill a constant bore hole diameter and to remain in the center of the hole. The bit has a sliding bearing pad on it that contacts the bore hole wall. The cutter positions are selected so that there is a lateral force from the cutters directed toward the pad and there are no cutters adjacent the pad. This causes the bore hole wall to form a portion of a journal bearing and thus stabilizes the bit as desired.

The up-hole end of the mandrel is stabilized and oriented as shown in **Fig. 4**. The mandrel rotates through the eccentric sleeve on bearings or bushings. The sleeve is fitted with external blades that resist the rotation of the sleeve in the bore hole. A latch is provided to lock the sleeve to the mandrel in a predetermined orientation when the drill string is rotated counter-clockwise. This allows the initial orientation of the sleeve and subsequent re-orientations to be accomplished simply by rotating the drill string counter-clockwise until the sleeve is in the desired orientation.

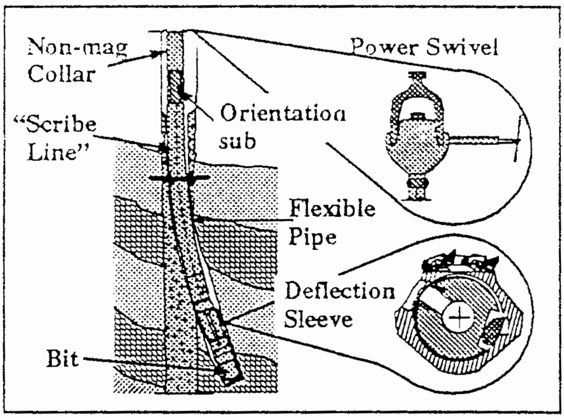

Figure 4: Curve drilling system.

A port in the mandrel and sleeve are designed so that the port is open when the latch is engaged. This provides a surface indication (reduction in pump pressure) when the mandrel is in a pre-determined orientation relative to the sleeve. The orientation of the sleeve can be determined by monitoring the surface orientation of the drill string when the port is open. **Figure 5** is a photograph of the 4-1/2" curve drilling tool eccentric sleeve and flexible joint.

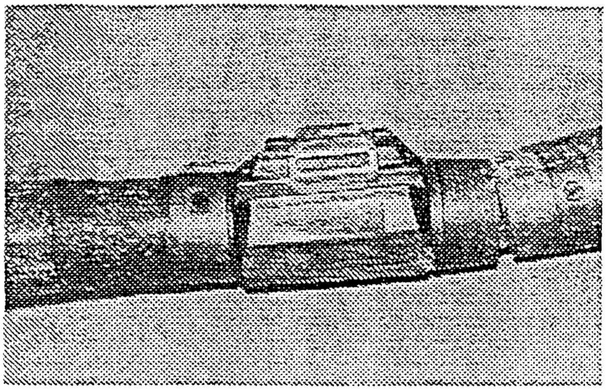

Figure 5: Photograph of 4-1/2" curve drilling tool.

In practice the curve assembly is positioned in the straight bore hole and a directional orientation survey is run to determine the orientation of the down hole end of the drill string. A surface orientation line is made on the drill string in the same direction as the reference point on the down hole end of the string. The drill string is rotated counter-clockwise until the port opens and then is rotated further until the orientation line is in the desired direction. The drill string is then reciprocated to remove twist and the result is that the sleeve is positioned in the desired orientation. This process is repeated at relatively short intervals until the curve drilling is completed.

The radius of curvature can be changed by altering the length of the rotating member between the bit and the sleeve. In practice this is accomplished by installing various length subs between the bit and the mandrel passing through the sleeve. **Figure 6** shows the results of running the 4-1/2" curve assembly with various tool lengths that range from 22.2 in. to 46.75 in. The resulting curvatures ranged from 31 ft to 176 ft. Also included on this plot is the theoretical curvature that would be drilled based on **Eq. (1)**. As can be seen there is a very good match between the observed result and the expected result.

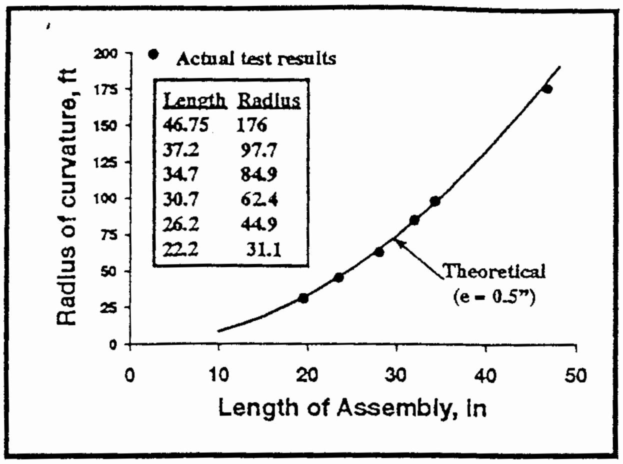

Figure 6: Observed curvature drilled with 4-1/2" curve assembly.

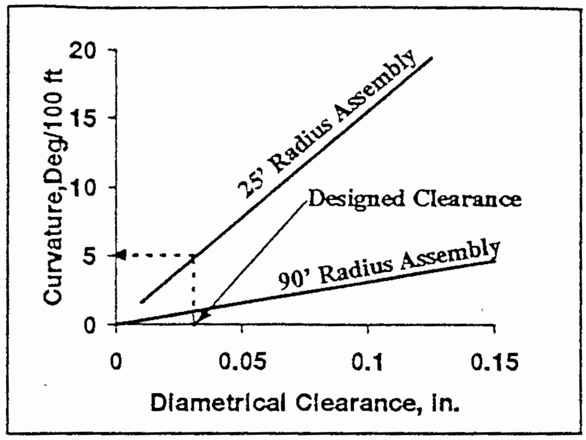

Figure 7: Curvatures due to clearance.

Lateral Drilling

After the curve is drilled to the desired final inclination, the curve assembly is removed and replaced with a lateral drilling assembly. The assembly used for this application has often simply been one composed of fixed length stabilizers with flexible joints placed between them to allow them to pass through a short radius curve. Although this type of assembly is still used relatively frequently, it does not always provide consistent performance.

In order for the assembly to pass around a short radius curve, the distance between the bit and first stabilizer must be short and when multiple stabilizers are used they must be connected with flexible joints. If the clearance between the stabilizer and the bore hole wall varies, then the assembly will not drill straight. For example, **Figure 7** shows the curvatures that can be expected for single stabilizer assemblies designed to the maximum length that will pass around a 25 ft and a 90 ft radius curve for various diametrical clearances. Notice that only slight clearances can generate significant build rates.

This tendency for the assembly to build angle is simply caused by the bit being tilted upward. If the stabilizer is completely full gage, then the tendency is eliminated, but the clearances are so critical that it is difficult to prevent the bit tilt without the stabilizer having to ream which will detrimentally affect the penetration rate.

One solution to this problem that has been found to work very well is to use an assembly consisting of the bit, spacer sub, undergauge stabilizer, and flexible joint, but provide a mechanism to cause the stabilizer to track around the bore hole as the string is rotated. This can be done in a number of ways, but the most effective has been to simply use a stabilizer with two slightly under gage pads and a third spring loaded pad to keep the two fixed pads pushed into the bore hole wall. This effectively causes the average position of the uphole end of the assembly to be in the center of the hole, although at any point in time it is displaced from the center. Keeping both the bit and stabilizer centered provides a straight drilling assembly. An additional benefit of this arrangement is that it provides extra clearance for getting the stabilizer in the hole. **Figure 8** shows a cross section through the spring pad stabilizer.

Flexible Drill String

The drill string that is used through the curved section of the bore hole must have adequate flexibility to pass through the curve without permanently deforming and must have sufficient fatigue resistance to provide an acceptable service life. For curvatures in the range of 25 to

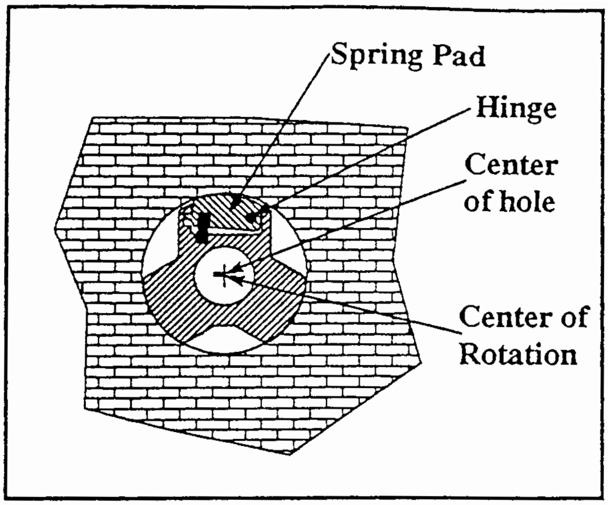

Figure 8: Cross section through lateral drilling stabilizer.

45 ft the most effective drill string is one constructed from a special carbon fiber composite pipe. This pipe has demonstrated that it can have adequate service life but is very expensive and in some cases has not had consistent performance.

An alternative to running the composite is to use a high grade of steel tubing (Q125 or S135) for curvatures greater than 45 - 50 ft. This pipe costs less than 10% of the composite but also has a very short service life. Its service hours and conditions must be monitored and the pipe taken out of service on a rigorous schedule to prevent in hole failures. Also when using it, the local curvatures must be monitored to make sure that there is not a localized area where the curvature is too high for the pipe to be used.

Surveying

Various surveying tools have been used with the system, but a commercially available surface read-out surveying tool has been specifically tailored for use with the rotary steerable system. The surveying tool consists of an inclination and azimuth unit that transmits the survey data to the surface via a single conductor wireline. The tool can be used for both surveying the bore hole and

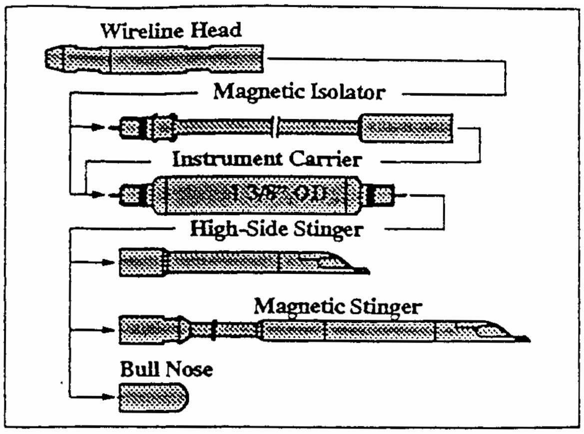

Figure 9: Components of thru-string survey tool.

for orienting the curve drilling tool. Of course it must be positioned in a non-magnetic collar

which can be composed of the carbon fiber composite, beryllium copper, or titanium, depending on the curvature that it must be run through. **Figure 9** shows the components of the survey tool. The diameter of the tool housing is 1-3/8" for operating through 1-1/2" bore tubulars. The tool is pumped to bottom for cases where the inclination is too high for the tool to slide.

One major advantage of the surveying system is that the survey is taken much closer to the bit than when the survey must be taken above a motor. This makes projecting the inclination at the bit much easier and reduces the problem of terminating a curve at the proper inclination, which can be a problem with motor systems.[7]

Completions

Most of the completions used with the lateral drilling system have been to simply leave the well bore with the open hole exposed. In several cases perforated and slotted liners have been run through the curve and lateral. Typically a 2-3/8" slotted liner can be run around a 30' or longer radius curve. Even though the pipe may yield when it is run, this has not prevented us from running the pipe and then pulling it back out to inspect it. A pre-packed screen and liner (shown in **Fig. 10**) has also been run around a 45' radius curve and pulled back out for inspection. Neither the screen nor the sand pack were damaged in this test.

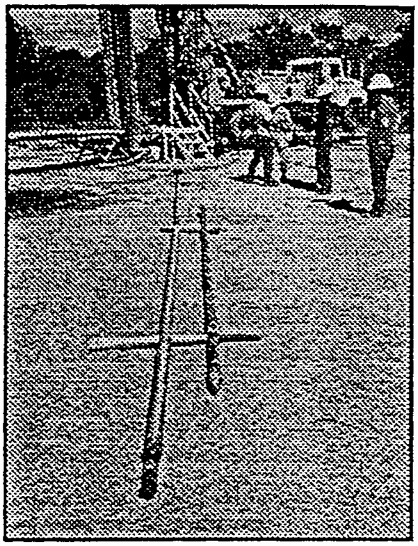

Figure 10: Pre-packed screen run around 45' radius curve.

System Status

The lateral drilling system was developed by Amoco, but has been licensed to a number of service companies in the US and Canada to provide commercial services with the technology. The first of these licensees became active in mid 1995 and to date a total of 26 commercial laterals have been drilled with the system. (About half this number of commercial wells were drilled with an earlier version of similar tools.) Four wells were drilled with dual laterals. **Figure 11** shows the cumulative number of laterals drilled with the system in the last year. There are several licensees that are yet to drill their first well as it usually takes about 6 months for financing to be arranged, equipment and staff to be procured, customers to be located, etc.

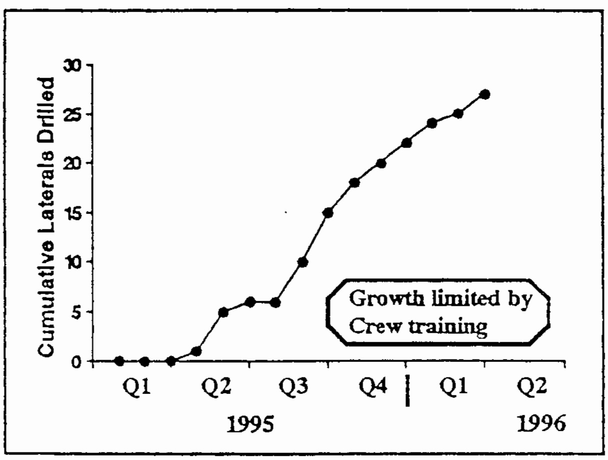

Figure 11: Wells drilled with the rotary steerable system during previous year.

Several examples are reviewed below to indicate the capability of the system, the types of wells that are being drilled with it, and the variety of conditions that can be handled. **Figure 12** shows a well drilled for Amoco in October of 1995 in the Antrim Shale. The 4-1/2" lateral was drilled as a recompletion of a vertical well completed with 5-1/2". The well was prepared and the lateral drilled with a work over rig operating only during daylight hours. The drilling fluid was a water based drilling mud and the flexible drill string was composite pipe. The drilling required 14 (9 - 10 hr) days for pulling the well, sectioning the casing, cementing, drilling the curve and lateral, and running the final survey. The booked cost for the total operation including the above activities plus completing and testing was $104,000.

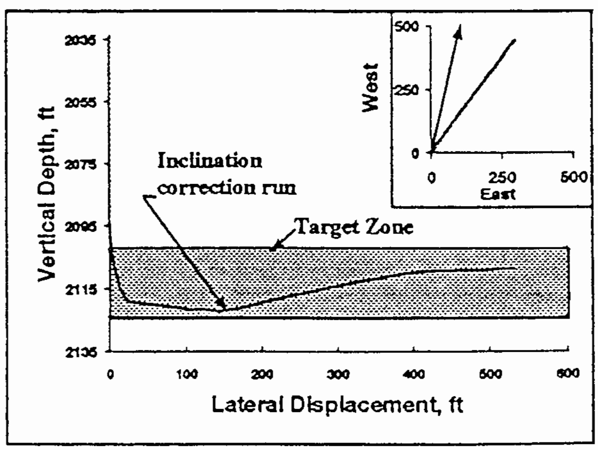

Figure 12: Antrim Shale well.

Figure 13 shows another well drilled by Amoco in a fractured shale at the Rocky Mountain

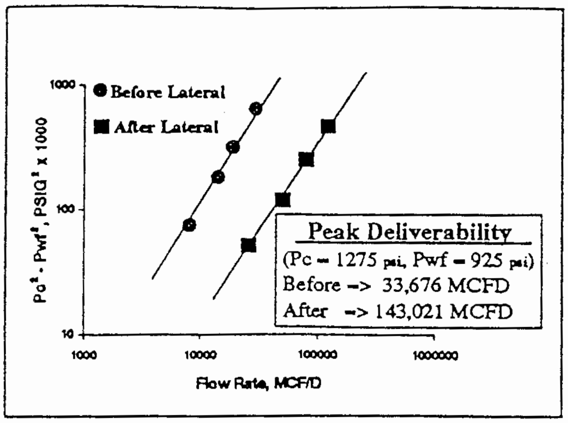

Figure 16: Deliverability from gas storage well.

to date have averaged around 3,500 ft depth, but wells as deep as 8,900 ft have been drilled with the system.

The production from the wells drilled in the last year with the system has ranged from dismal to quite good, but overall has not been as good as hoped. Although 85% of the laterals attempted with the system are considered drilling successes, only approximately 50% of the wells are considered production successes. Most of the poor production results can be directly attributed to inappropriate candidate selection.

The cost for the wells depends on the particular situation, but **Table 1** provides costs estimated by HVI for a typical onshore USA well. These numbers were prepared for the case of drilling a 500 ft lateral below a 45 ft radius curve and for a 1000 ft lateral below a 90 ft radius curve. They are based on HVI's experience (driller of 60% of the wells with the system) and seem reasonable based on our experience. The completion operation used in the estimate is simply an acid wash with the well being left open hole. More exotic completions would add to the cost.

Typical Onshore USA Costs[1]

	45'/ 500'	90'/ 1000'
Prep, Section, Cement	$ 22,300	$ 28,800
Drill & Survey Curve	39,300	44,800
Drill & Survey Lateral	35,200	63,400
Completion	5,000	5,000
Total	$101,800	$142,000

Note 1: Generic cases estimated by HVI

Table 1: Well cost estimates for the rotary steerable system.

Future Developments

The three greatest limitations of the system are the wide directional window, difficulty of orienting in deep and/or directional wells where there is significant twist in the drill string, and limitations of the flexible pipe. The wide directional window should be reduced significantly by the availability of the surface readout survey tools to allow the direction to be corrected as the curve is drilled. These tools are currently commercially available and are just beginning to show up in the field. As a demonstration of their ability to maintain closer directional control, they were recently used at our test site to maintain a 175 ft radius curve within 1° of the target direction as shown in **Fig. 17**.

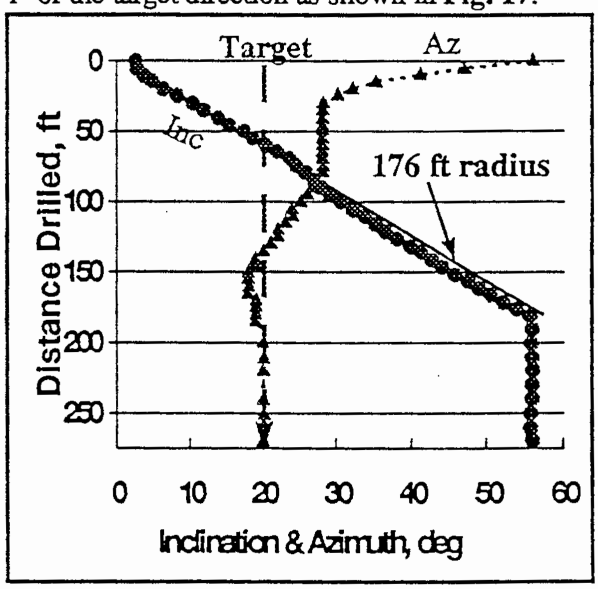

Figure 17: Survey tool application for directional control.

The target direction was at an azimuth of 20° and the initial well heading was about 60° with

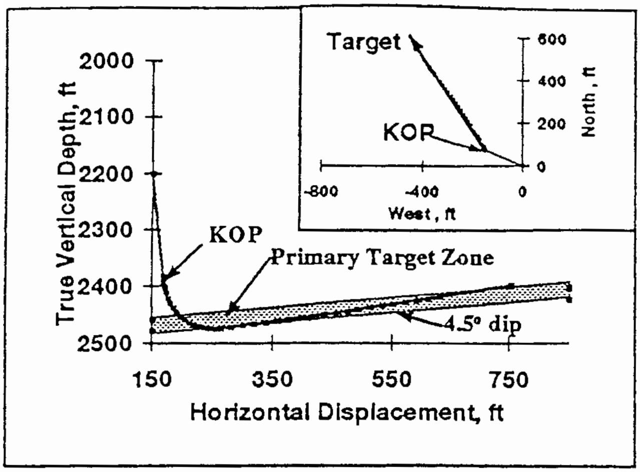

Figure 13: Niobrara fractured shale well.

Testing Center at the Naval Reserve No. 3 near Edgerton Wyoming. Both the curve and lateral were drilled with mist as the circulating medium and 2-3/8" S135 drill pipe as the flexible drill string. The top of the primary target was overlain with a bentonite bed above which was a secondary target zone. This well required 72 hours from the time the pilot hole was drilled until the lateral was completed and the final survey run. The lateral was terminated when the bentonite at the top of the zone (when encountered the second time) produced mud rings that could not be cleaned up.

Figure 14 shows a well drilled into a tight gas sand at about 8,300 ft. The curve and lateral was drilled with an oil based mud and Q125 tubing as the drill string. This well was drilled by Horizontal Ventures, Inc (Tulsa, OK). It

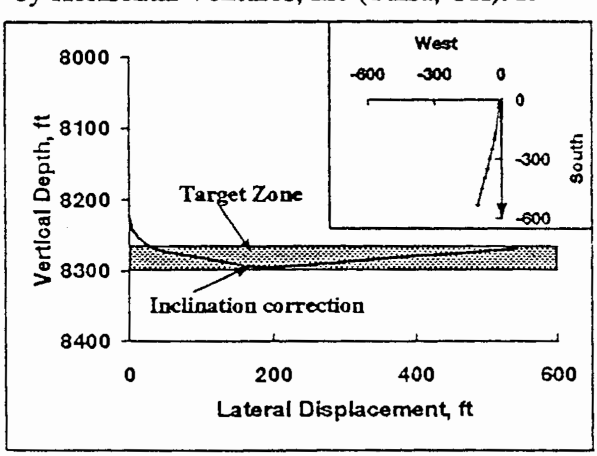

Figure 14: Lateral drilled in Morrow sand.

demonstrates the ability of the system to hit a 30 ft thick target at a relatively deep depth. Staying in the target required that the curve assembly be re-run after drilling about 100 ft of lateral in order to increase the inclination adequately. The well required a total of six (24 hr) days to drill.

Figure 15 shows an example of dual laterals drilled by HVI in a sandstone gas storage reservoir for Oklahoma Natural Gas. This well was drilled with the composite pipe so that the complete curve and lateral could be placed between the casing shoe and water level in the reservoir. This is one of six wells drilled in this storage field by the Amoco technology. Two of the wells were dual laterals.

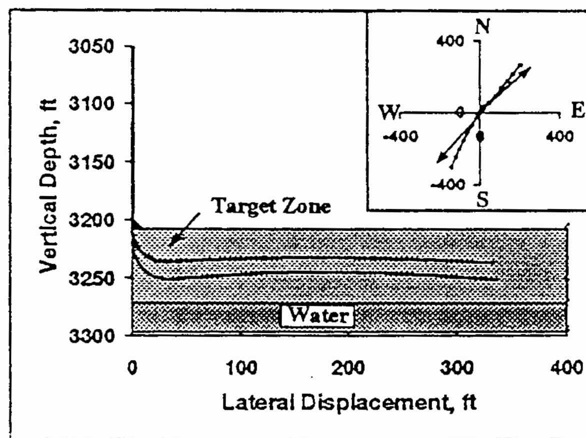

Figure 15: Dual laterals in gas storage field.

Five of the wells are currently active wells and have significant production increases as indicated in **Fig. 16** for the well shown in **Fig. 15.**[11] The sixth well is shut in because of excess water production due to the end of the lateral getting into the bottom water.

These examples of wells drilled with the rotary steerable lateral drilling system demonstrate the current capabilities of the system. Lateral lengths of 200 - 700 ft can typically be drilled, depending on the radius of curvature used and the thickness of the target zone. The direction of the lateral is typically within 20° of the target direction, but is rarely exactly on target. Most of the wells drilled was oriented at an azimuth of 10° to provide a slight lead to offset slippage of the eccentric sleeve. The well built angle and turned until the direction held constant at about 30°. After drilling about 80 ft, the survey tool indicated that the heading had leveled out at an azimuth of 30° and the well needed to be turned more. The orientations were adjusted to due North and were maintained until the survey tool indicated that the well was on course. Notice that the inclination build rate was along a 176 ft radius curve until the curve tool was oriented to simultaneously build and turn. After the turn was completed the build rate returned to a radius of 176 ft. After the build was completed, the spring block lateral assembly was run and held both inclination and direction constant.

The second difficulty of orienting in situations where there is large amounts of twist in the drill string will also be improved by using the through drill string surveying system. It can be reduced further by incorporating a down hole sensor to indicate the orientation near the bit relative to "high side". Such a tool is currently under development and should be available within the next few months.

The limitations of the flexible pipe is also being dealt with. The carbon fiber composite pipe has proven that it can have an economical life and can be used to drill radii slightly less than 30 ft. Its consistency in performance could use a little improvement and it is still very expensive relative to the goals of the overall drilling system. Active work is under way toward providing a titanium pipe that may be very competitive with the composite pipe both from a performance and cost perspective. For situations where the curve can be drilled at a radius of 50 ft and greater, steel pipe probably provides the best overall solution in terms of performance and cost, but requires a rigorous replacement schedule.

Summary

Slim hole re-entry wells are being drilled at a very active pace to enhance production in both mature reservoirs and pay zones that have previously been bypassed. A new slim hole, rotary steerable drilling system has been developed and commercialized that is ideally suited to drill these types of wells. It can work inside casing as small as 4-1/2", can drill curves with radii of 30 - 100^+ ft, and is well suited for drilling lateral lengths of 200 - 700 ft. The system can be used with both mud and air as the drilling fluid and is probably better thought of as a completion technique rather than as a drilling method.

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