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AADE 2009NTCE-05-04 ROTARY STEERABLE TECHNOLOGY CREATES VALUE IN WESTERN CANADIAN DRILLING ENVIRONMENT

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Abstract:

In today's world, drilling is mainly driven by performance efficiency. Every operator strives to reduce the cost of drilling without compromising the quality of the wellbore. A low-quality wellbore can limit the life of a well by compromising the success of subsequent operations such as logging, casing, and fracture treatment.

One of the major challenges to wellbore quality in western Canada is directional control. The geological environment makes directional control difficult. Even vertical wells require some kind of control to stay vertical. A positive displacement motor (PDM) is the most common means of maintaining directional control in both vertical and directional wells. However, sliding is required to make directional changes with a PDM. Sliding exposes the drilling assembly to wellbore friction, thereby impacting the weight transfer to the bit. The combined effect of reduced weight on bit (WOB) and rotation speed results in loss of performance in the form of reduced rate of penetration (ROP). This effect is more pronounced when drilling with fixed cutter polycrystalline diamond compact (PDC) bits. Furthermore, the combination of rotating and sliding creates an additional tortuosity that may impact the quality of the borehole.

Rotary steerable system (RSS) technology is addressing these challenges with a design that maintains directional control without sliding. The entire drillstring is rotated from surface, thus keeping the wellbore friction at bay. Better weight transfer and consistent rotation speed at the bit result in consistent ROP and therefore consistent performance. With PDC bits, the performance improvement can be an order of magnitude.

RSSs have been in use in western Canada for the last few years. This paper reviews the drilling performance in Burnt Timber, Narraway and Big Horn/Saunders fields. It presents the methodology for selection of suitable candidates for RSS, the application of the methodology to the wells in the fields, and results of drilling performance, including comparisons with other wells drilled in the fields.

Introduction

This section offers an overview—from a driller's perspective—of the oil- and gas-bearing basins in western Canada.

In western Canada the foothills of the Rocky Mountains, which run from the northwest to the southeast on the eastern side of the British Columbia and Alberta border, are exploited for gas. The area is characterized by complex geology that reflects the creation process of this Rocky Mountain belt. Steeply dipping formations are typical and pose problems for directional control. If a wellbore is allowed to drift without any control, it generally takes a northeast direction. The continuity of formation beds has been disrupted by faulting and folding processes. Lithology in this area exhibits everything known to drillers, including the soft shales of Fernie, Blackstone, and Kaskapau, which are drillable with PDC bits, and the hard and abrasive conglomeratic Cadomin and Nikannassin formations, which drill very slowly with heavy insert bits. Clean lithology sections are usually an exception. Formations are made up of interbedded layers of shales, sands, claystone, limestone, dolomites, and chert. Depending upon the depth of the target horizon, a typical foothills horizontal well can take 3 to 6 months from spud to completion. The foothills have been drilled with a variety of wells profiles including vertical, J-shaped, S-shaped, and horizontal. A typical foothills well has a 17½-in surface hole with 13 3/8-in casing set below 600 m to cover the groundwaters. The intermediate hole varies from 7 7/8 to 8¾ in and is typically drilled to the top of the reservoir where 7-in casing is run. The size of the typical production hole is from 6 to 6½ in.

Northeast British Columbia can be split into two areas for discussion purposes. The areas adjacent to the Rocky Mountains exhibit an environment similar to that of foothills and have also been exploited for what is known as conventional gas. It is the exploitation of unconventional gas that is expected to rapidly accelerate drilling activity over the next few years. Unconventional gas, also called shale gas, is the term used for the gas trapped in shales. Recent advancements in fracturing have made economic recovery of this gas possible. The area north of Fort Nelson, also called the Horn River basin, is rich in shale gas, and drilling activity there is expected to continue. This area and a similar shale gas giant called Montney, north of Fort Saint John and stretching from Alberta to British Columbia, have sparked great interest. Formations in Horn River basin are more predictable than those in the foothills. Several sections of shales about 1500 m thick are typically encountered from drillout of surface casing to the zones of interest: the Muskwa, Evie, and Otter Park formations. The shales are overlaid by a cherty, loosely consolidated formation called Debolt. Once that formation is cased, most of the shales are drillable with PDC bits. The challenge is achieving the build rates in the softer shales to land the wells and drill horizontally.

Why Rotary Steerable Systems?

Historically, PDMs have been accepted as a reliable technique for making direction changes for vertical wells or any other directional profile. The directional change is achieved by a process called sliding, whereby the toolface of a motor is pointed in the desired direction and drilling is commenced without rotation from surface, resulting in hole being made in the required direction. The term toolface is used for the directional orientation of the part of the motor below the bend in the bent housing. The angular offset of the toolface from the orientation of Measurement While Drilling (MWD) tools is recorded and transmitted to surface, which then enables real-time monitoring.

Sliding has drawbacks. It introduces a curvature in the wellbore, which is more commonly termed a dogleg and is expressed in degrees per 30 m. Figure 1 illustrates doglegs introduced in an attempt to keep the hole vertical. The well was being drilled through a series of coal seams with strong drift tendency. The process of correction brought inclination down, but it also introduced extreme curvature on the order of 4 to 12 deg/30 m, thus resulting in a tortuous wellbore.

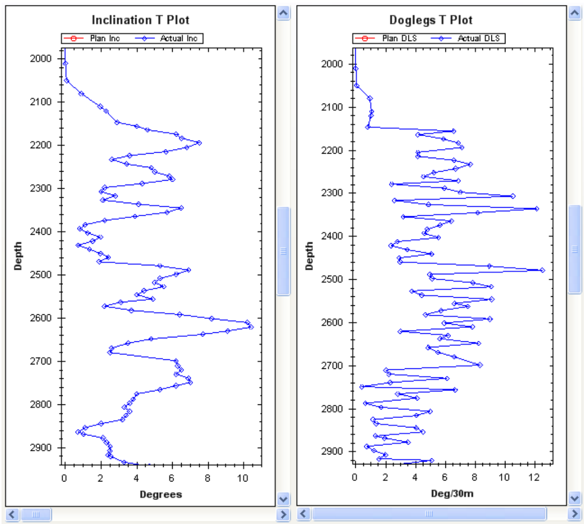

Figure 1: Example of doglegs in vertical hole

The doglegs result in undesired contact points in the wellbore that lead to increased friction and partial diversion of energy from drilling to overcome the friction. Drilling in areas that exhibit strong and consistent drift tendency, such as the foothills, requires frequent corrections for direction. These corrections cause recurring contact points that reduce the drilling efficiency and result in a poor-quality borehole. Such a borehole pushes the environment closer to the operational limits for components, and as a consequence reduces the depth to which a well can be drilled. Vertical sections are often cased before the production hole is drilled. Although casing somewhat masks the doglegs, in the process it becomes susceptible to wear due to frequent contact with the drillstring and high side forces. The material used for hard banding on tool joints is designed to be harder than the casing, and loss of pressure integrity may occur because of excessive casing wear. This phenomenon is well known and documented in the deep foothills wells targeting the carbonate reservoirs of Turner Valley formations. In this area a 1,000-m-long lateral section may take up to 2 months to drill. The loss of pressure integrity of the intermediate casing can have consequences in the form of expensive casing repairs, which in some cases may result in the need for smaller completion sizes.

Figures 2 and 3 compare the continuous inclinations of build sections achieved with an RSS and a PDM. Continuous inclination is a measurement of inclination taken by the MWD tool in real time and sent to surface at 3-s intervals. Both figures show two curves: the survey inclination in red and continuous inclination from the motor in blue. In Figure 2, the continuous inclination curve forms a stair-step pattern. It stays flat when the drillstring is rotating and rises when the system is sliding. The picture shows a build of 8 degrees over 55 m, giving an average dogleg of 4.4 deg/30 m. The average dogleg figure is misleading because it does not reflect the true state of the wellbore. In reality, the build from slides yields a higher instantaneous curvature. A close inspection of the slide from 3,500 to 3,504 m, where the inclination went from 52 to 54.5 deg, shows that the severity of the dogleg was 18.75 deg/30 m. In this case the tortuosity of the wellbore is 14.75 deg/30 m higher than planned. The torque and drag models are not usually run with input parameters which reflect such high tortuosity and hence do not depict actual results. The severity of the instantaneous doglegs depends on the choice of bent housing setting and sliding percentages. It is theoretically possible to reduce the instantaneous dogleg by using a less-aggressive bend. However, that also means a higher slide percentage and therefore loss of drilling efficiency as ROP is reduced while sliding.

The continuous inclination plot of a similar build section made with an RSS is shown in Figure 3. The continuous inclination curve tracks the survey inclination curve. The measured dogleg is the actual dogleg.

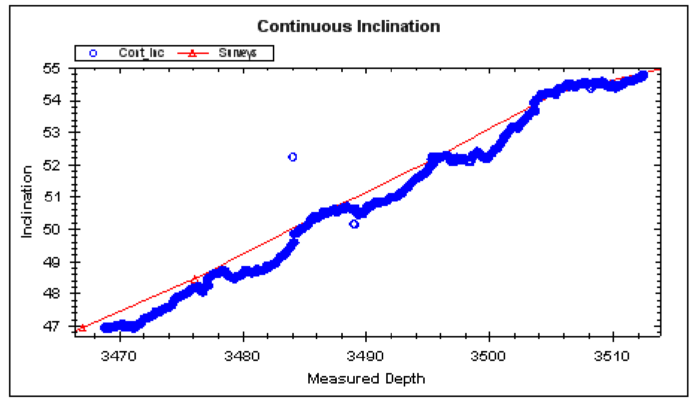

Figure 2: Continuous inclination of a motor build section

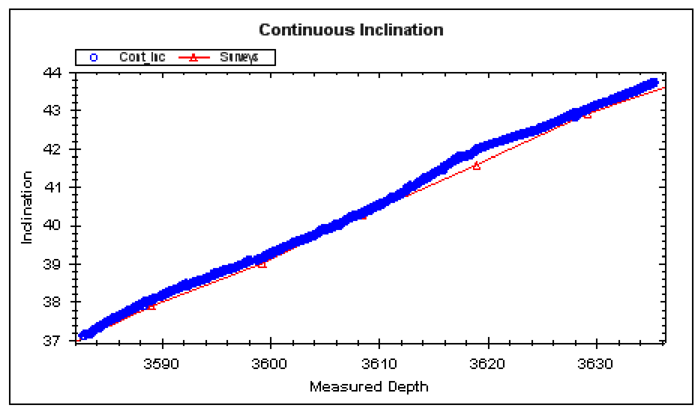

Figure 3: Continuous inclination of an RSS build section

As mentioned previously, a poor quality bore hole ultimately limits the depth to which a well can be drilled. To over come added friction in the well bore, additional pull is required to lift the pipe thus increasing the hole drag when tripping and additional torque is required while rotating. Drilling can only continue until the torque and drag are within safe limits of the rig equipment capabilities and drill string specifications.

Figures 4 and 5 compare the tripping hook loads for two wells, one drilled with a PDM and one with an RSS. Both wells were drilled with the same rig in the same area and through the same sequence of formations. The red curves show hook loads while tripping out, and the blue curves show the loads while tripping in. At 3,000 m the drillstring in the RSS-drilled well required 135 kdaN of pull at the hook. For the same depth in the well drilled with motors the pull required was 155 kdaN. The motor-drilled well was intended to be vertical to 3,000 m. Its actual inclinations are shown in Figure 1. The RSS well kicked off at 2,700 m; its inclination is shown in Figure 6. The well drilled with an RSS exhibited less tortuosity. Its doglegs in the vertical part were less than 0.5 deg/30 m, much less severe than those in the motor-drilled well illustrated in Figure 1. Hence, less hook load was required.

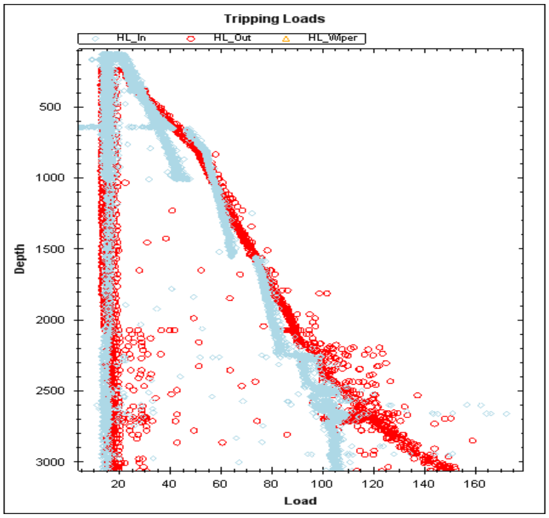

Figure 4: Tripping hook loads of motor-drilled well

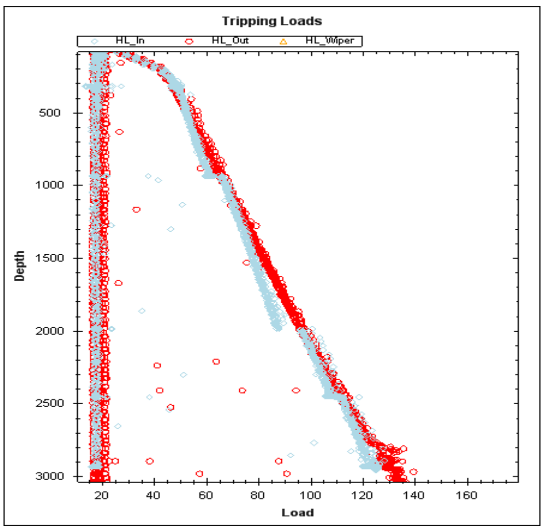

Figure 5: Tripping hook loads for RSS-drilled well

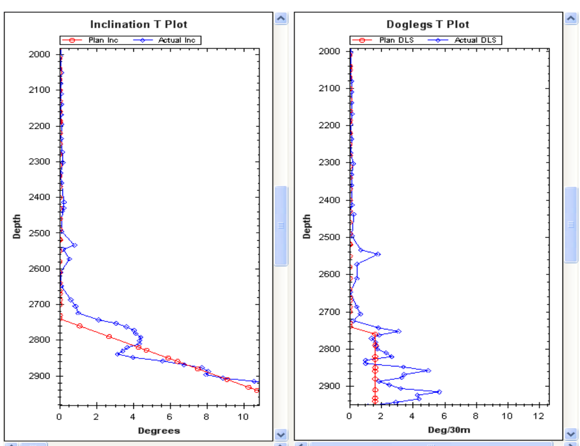

Figure 6: RSS-drilled well inclination and doglegs

An increase in wellbore friction makes sliding in the lateral sections more challenging. Weight slacked from surface is transmitted to the bit through the drillstring. With increased wellbore friction more weight needs to be slacked from the surface to overcome the friction associated with the contact points, in addition to what is required for drilling at the bit. Any reduction in tension at the surface shifts the neutral point of the drillstring up. There comes a point when there is sufficient compression in the drillstring to cause it to buckle instead of to transfer weight. When the buckling becomes helical, sliding is impossible and therefore directional changes cannot be made. At this point drilling can continue only in rotary mode with no way to make directional changes.

There is higher flat time associated with motor drilling when PDMs are required to achieve directional changes. The term flat time comes from time-depth curves; it is the time duration for which the curve no longer advances along the depth axis. Typically, a slide is initiated at the start of a connection. At this point a command is sent to the MWD tool to initiate the survey, and then the driller waits until the toolface direction is obtained. If the toolface is not pointing in the right direction, the drillstring must be picked up off bottom and rotated from surface until it is in the desired direction. The drillstring is then lowered, and drilling commences for the interval over which sliding is required. After the slide is complete the bit is picked up off bottom and the slide interval is reamed down prior to continuing drilling in rotary mode. The time associated with acquiring the MWD survey and toolface direction, orienting the toolface, and reaming the slide interval is required only for sliding mode. It can be eliminated if the directional change can be made in rotating mode. The time savings can be significant when drilling with PDC bits in a rock where control of the toolface is erratic. Figure 7 compares the time-depth curves of motor-drilled (red) and RSS-drilled (blue) wells. The bit-depth curves are superimposed on the hole-depth curves in orange (motor) and light blue (RSS). It is fairly obvious that the off-bottom time associated with sliding results in a threefold reduction in effective ROP.

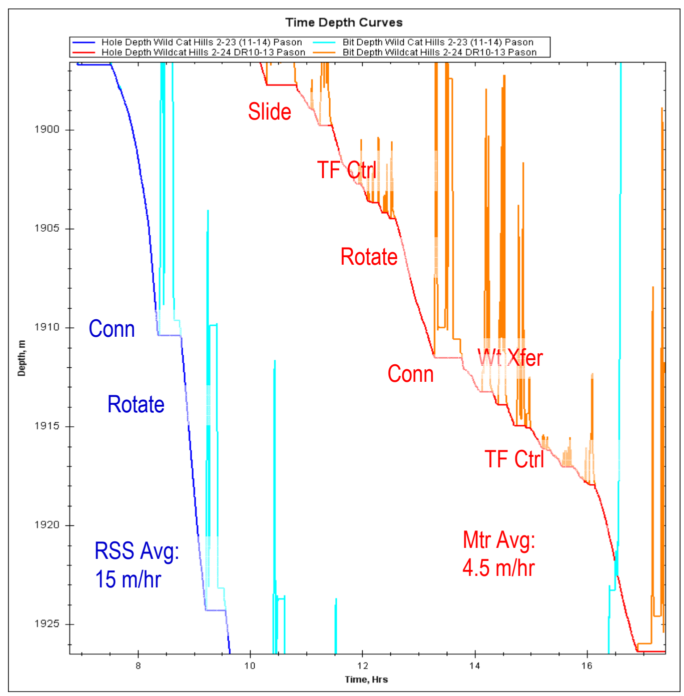

Figure 7: Higher flat time with motor (red) than with RSS (blue)

Sliding ROP is always less than rotary ROP. The reason lies in the rock-failure mechanism. With an insert bit the rocks fail by a combination of weight and speed of rotation. Weight provides the crushing force and rotation provides the shear components as well as the mechanism to clean the crushed rock. When sliding, both bit speed and weight are less than when rotating. Rotation is reduced because the bit cannot be rotated from surface to maintain the toolface. The only bit rotation is provided by the downhole motor. Weight reduction comes from a combination of factors. Sliding exposes the drillstring to wellbore friction, and therefore the weight slacked from surface is not the same as the weight transferred to the bit. The second component is reactive torque from the bit. As weight is transferred and the bit takes a bite into the formation rock, it needs torque to gain a balance of forces. In the absence of torque the toolface does not remain in the direction it was originally pointed. The process is more pronounced when the rock-failure mechanism is predominantly shear; i.e., when drilling with PDC bits. Reactive torque is usually managed by limiting the WOB and results in loss of performance. Figure 8 illustrates an example of the difference in rotary and sliding ROPs. A PDC bit was used with a slow-speed motor in order to prolong the length of the run. The combination of less WOB (for toolface control) and rotation speed resulted in sliding ROPs that were less than half those of rotary ROPs.

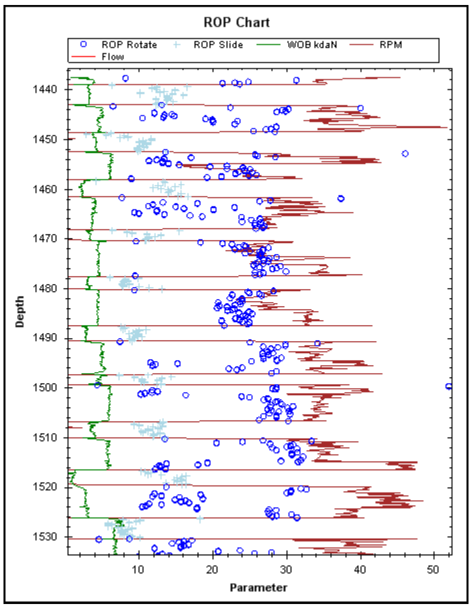

Figure 8: Sliding versus rotating ROPs

Evolution of RSS in Western Canada

Rotary steerable tools have been used in western Canada since 2002, as illustrated in Figure 9. There are two kinds of RSSs in use: push the bit and point the bit. Drilling in western Canada has predominantly benefitted from the first. It is a closed-loop system comprising two main components, a control unit and a bias unit. The control unit contains sensor packages, which are held geostationary by the servo action of two turbines energized by drilling fluid. The turbines also provide the mechanism for receiving commands from the surface through detection of flow rate variations, a process called downlinking. The settings required for tool operation are downlinked to the tool. The sensor package provides measurements of inclination, azimuth, and gamma ray. These are compared with the downlinked settings and a desired toolface setting is resolved. The consistent direction provides the mechanism for directing drilling fluid through the preferred port in a hydraulics valve to the desired pad on the body of the bias unit. When a pad is actuated it is pushed out against the formation, thereby providing a side force while rotating. This push is matched by an equal and opposite push by the formation, which results in a direction change at the bit.

The push-the-bit system was introduced in western Canada in 2002. Early applications were in 8 3/4- and 12 1/4-in holes for maintaining verticality. By 2008, 175,000 m had been drilled with these tools. Hole sizes ranged from 6 1/8 to 17 1/2 in. and applications varied from vertical, J-shaped, and horizontal drilling in geographies from the plains of southeast Saskatchewan along the foothills to northeast British Columbia's unconventional gas plays. The economic value has been significant, driving its acceptance as a cost-effective alternative to conventional motor drilling.

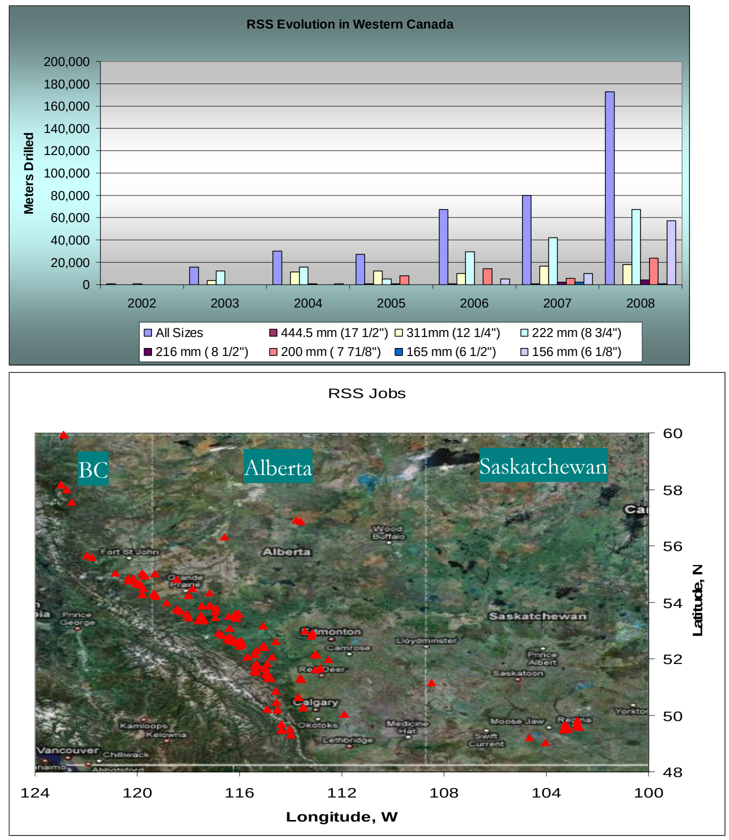

Figure 9: RSS evolution 2002–2008 (source- google maps)

Case History No. 1 (Narraway)

PetroCanada had drilled several wells in the Narraway area using conventional downhole motor technologies, with mixed results. The lithology column in this area shows fairly interbedded medium-strength formations from the drillout of surface casing to the top of the Kaskapau shale. The Kaskapau formation, which lends itself to drilling with PDC bits, is a fairly thick section and leads to relatively thin sections of various other formations with mixed strengths prior to reaching the casing point. Various combinations of bits had been tried with motors. The most consistent results were obtained with insert bits because they offered better toolface control through the thick shale section. The plan was to use an RSS to drill the section in three runs. Run 1, with an insert bit, would be from drillout of surface casing to the top of the Kaskapau formation. Run 2 would use a PDC to drill through the Kaskapau to the top of the Dunvegan formation. The third run would take the well to the section total depth (TD). The RSS-drilled well reached section TD 12 days earlier than the previously drilled wells, as illustrated in Figure 10. This was made possible by the better ROP achieved with the PDC bit (Figure 13) and a reduction in trip and flat times. The average ROP of 18 m/h was 38% better than the previous best of 13 m/h.

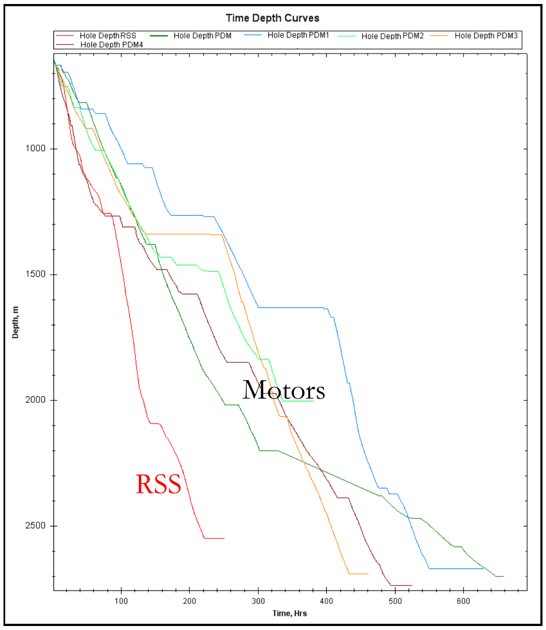

Figure 10: Narraway time-depth curves: RSS-drilled well in red

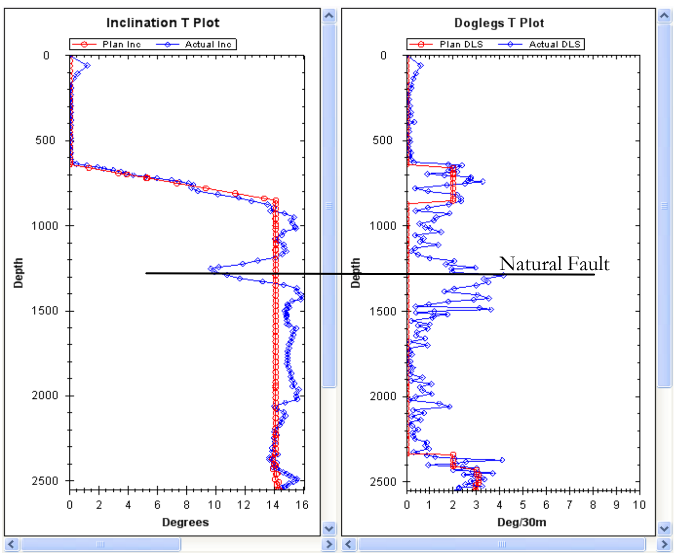

Figure 11: RSS inclination and doglegs (plan versus actual)

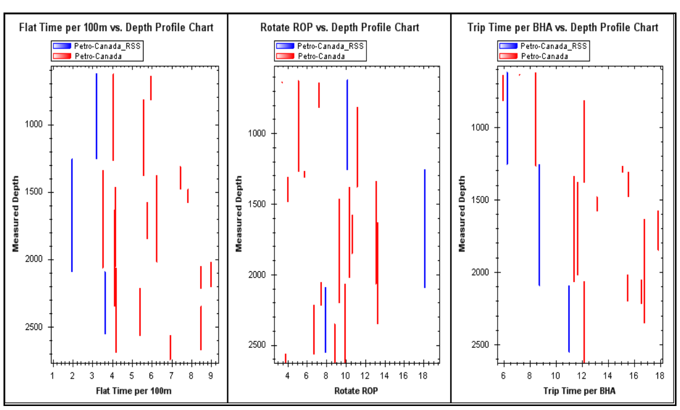

Figure 12: Key performance indicators: RSS (blue) versus PDM (red)

The flat time of 1.95 h/100 m of drilling was 45% less than the previous best flat time of 3.5 h/100 m of drilling in that section. A comparison of key performance indicators for all RSS runs with motors is provided in Figure 12.

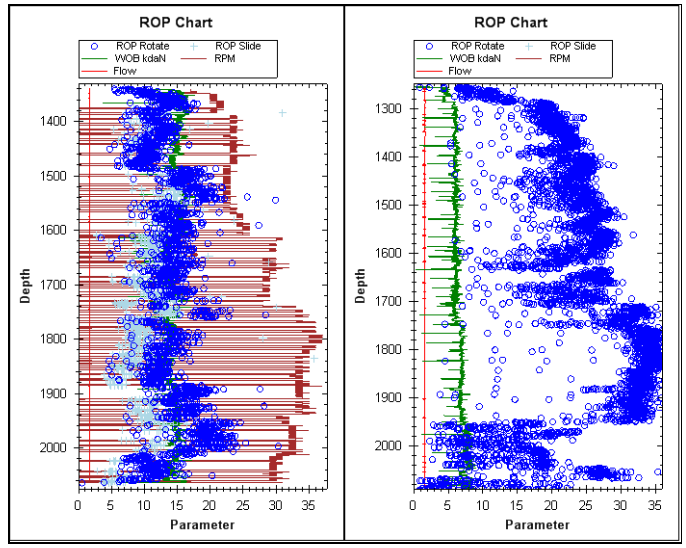

Figure13: ROP comparison: PDM+insert (left) versus RSS+PDC (right)

Case History No. 2 (Saunders)

Wells in this area are drilled vertically to 2,700 m true vertical depth (TVD). Surface casing is set at 635 m. Vertical hole is followed by a build to set the casing point in the middle, dense dolomite and then by a horizontal section through the Elkton formation. The nature of the formations, conglomerates, sandstones, and coals makes this area traditionally slow to drill. Up to 2 months of drilling may be required to reach the intermediate casing point and about 4 months to reach total depth. Long drilling times expose the casing to drillstring rotation, resulting in excessive wear. Casing wear can be minimized by reducing the dogleg severity of the wellbore. Low tortuosity also helps in weight transfer to the bit while drilling the lateral section. Figure 13 compares the inclination of an RSS-drilled well with that of a motor-drilled well. The RSS consistently keeps the inclination below 0.5 deg for the entire length of the vertical section.

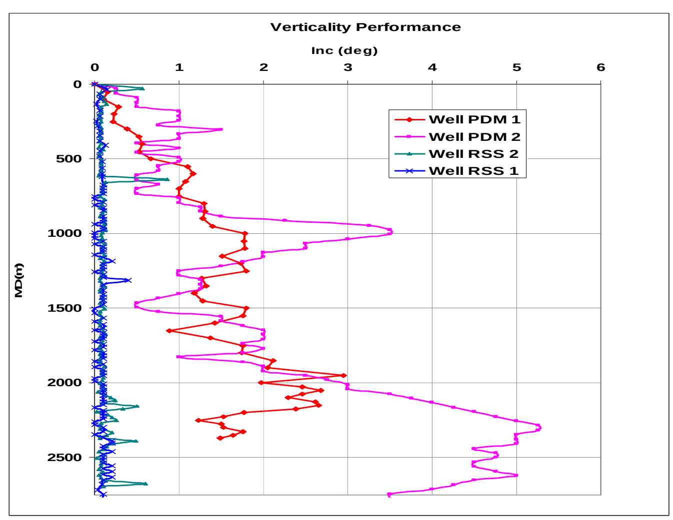

Figure 14: Inclination comparison: RSS versus PDMs

Case History No. 3 (Burnt Timber)

For two wells of this field, 8¾-in production holes were drilled from the surface casing at 625 to 2,700 m TD. Well 1 used an RSS bottomhole assembly to drill out the surface casing shoe to 957 m, then two PDM assemblies were used to drill to TD at 2,660 m. Well 2 used three RSS bottomhole assemblies for the entire section (627 to 2,765 m).

A comparison of ROPs for the two wells is presented in Figure 15. During the PDM runs in Well 1 the rotating ROPs were higher than in Well 2, but the sliding percentage was quite high (56%) and the sliding ROP was 55% of the rotating ROP. As a result, the average ROP for the section drilled with a PDM was 6.5 m/h, which is about 50% of the average ROP in Well 2. Drilling with the RSS reduced flat time by 50%, and the entire section was drilled 3 days sooner than with the PDM, as shown in Figure 16.

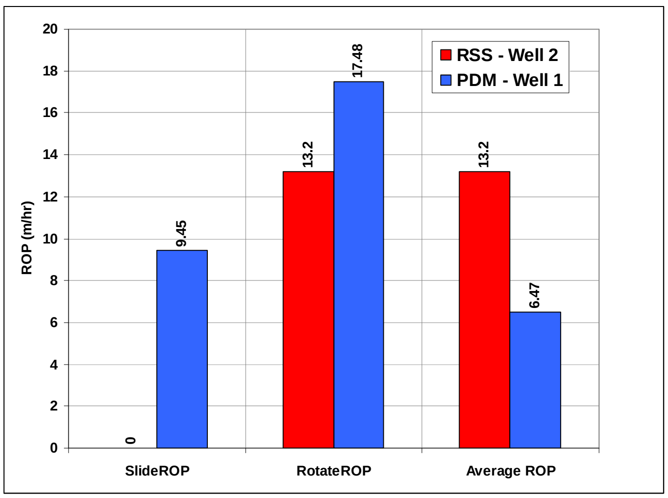

Figure15: Comparison of ROPs: PDM versus RSS

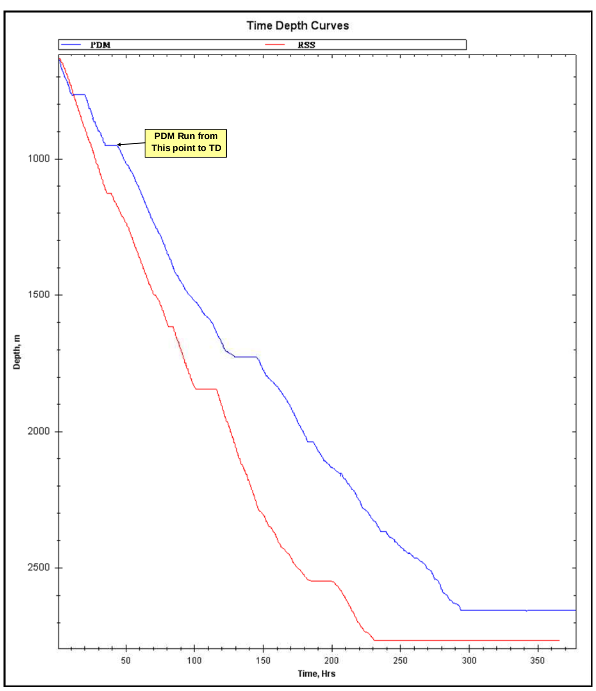

Figure 16: Time-depth curves: RSS (red) versus motor (blue)

Conclusions

Rotary Steerable Systems have evolved into a mature service by consistently drilling better quality well bores in lesser time. The quality of an RSS well bore is superior to one drilled with conventional motors by virtue of the continuous rotating action. Smooth hole reduces drag, improves weight transfer and helps in extending the length of lateral sections. RSS creates value by reducing the time required to drill the well thus offsetting the additional expense of running the service.

Glossary of Terms

BHA: Bottom hole assembly

PDM: Positive displacement motors

MWD: Measurement while drilling

GR: Gamma Ray

RSS: Rotary Steerable System

AFE: Authorization for expenditure

ROP: Rate of penetration

WOB: Weight on bit

TD: Total depth

KPI: Key performance indicator

DLS: dogleg severity

RPM: Revolutions per minute