Advanced Technologies, Solutions Are Improving Wellbore Construction

One case history outlines the challenges of drilling well pairs from a pad in a steam assisted gravity drainage field.

PathFinder was awarded a contract to drill a complex steam assisted gravity drainage (SAGD) nine well-pair pad to be completed over the top of an existing nine-pair pad. It is difficult enough to drill the original well pairs and keep them near one another. To accurately place the well pairs in order, the company used a proprietary methodology called a single entry solution. This technology requires that the company intervene into only one well bore to range to the second well bore. The result was that all of the well pairs were placed per plan within 16 ft of each other.

The company uses a technology known as RADAR real-time analysis of drilling and advanced ranging to aid in accurate well pair placement. “Other companies have to range to the lower well from the upper well and to intervene via wireline, coil tubing, or tractors to pull the magnetic system,” said Allan Rennie, manager of the PathFinder business and product line. “Our system works by gaussing or magnetizing the casing of the lower well before it is run and set, then drilling the upper well, and ranging to the magnetic signature of the casing.

“Additionally, we are the only company in the industry in placing SAGD well pairs that validates the ranging method,” Allan said. “We use a secondary method to calculate the distance to our target, a triangulation method when we are merging, diverging, or crossing over the well. Then we calculate the distance to our target from that and we compare it to our ranging method.”

According to Allan, this is a control or a secondary methodology to validate the accuracy of the company’s ranging survey. The following case history outlines the challenges and solutions to successfully drilling well pairs from a pad in a SAGD field. The new wells were drilled with positive displacement motors. The case history outlines a systematic approach to correctly placing these SAGD well pairs per plan. This is achieved by first considering the entire development and accurate placement of the project field, well pad, well pairs, and well(s).

The case study area reviewed is in the heavy oil sands of the Foster Creek region of northeastern Alberta, Canada. Several techniques are implemented in this approach and are encompassed within the RADAR services. In well twinning, highly accurate well placement of the producer well bore is followed by ranging, gravity MWD (GMWD) and at-bit measurements to correctly place the injector well bore per plan.

The complex well plans (shallow depths and long horizontal sections) for SAGD well pairs highlight the need to minimize tortuosity in all areas of the well bore. In-depth pre-well planning reviews of the well plan/profile to include torque and drag calculations help minimize the torque and drag of the bottomhole assembly (BHA) along with accurate execution of the well creation leads to a reduction of tortuosity. Minimizing borehole tortuosity in these wells, coupled with rapid, accurate real-time evaluation while drilling, enables fast steering decisions to place these well bores per plan and to improve the project’s drilling economics.
The initial drilling of a set of well pairs (producer and injector) from a pad for heavy oil development is often accomplished using standard well creation techniques for the initial wells, in this case the producers, followed by the careful drilling of the parallel wells using advanced ranging techniques to accurately control the separation of the paired wells. When drilling the initial well, it is critical that the position of the well be accurately known. To do this, surveys are analyzed using advanced techniques such as multistation analysis to yield the most accurate definition of the well path. Careful control of the directional drilling process also is critical. During large azimuth adjustments, it is important that the tortuosity of the well be minimized. Accurate inclination control (and thus TVD) is equally important during the lateral section. This is aided by at-bit determination of inclination. Controlling rather than maintaining a uniform TVD may be required as the zone of interest may vary laterally.

The second well also must be carefully drilled and placed. Many of the above requirements are duplicated. During the build section, azimuth often needs to be controlled in the presence of magnetic interference.
This is accomplished using an alternate technique, GMWD, which allows the accurate determination of the well azimuth. Using passive ranging enables continuous determination of the well’s location and anticipating changes in drilling parameters needed to maintain the required relative position of the paired wells.

Drilling infill wells presents other challenges. Infill wells are often attempted several years after the initial development and the knowledge of the existing wells’ positions is less sure. In these cases, the wells are best drilled with careful analysis to detect magnetic interference to ascertain that the well correctly maintains the desired separation from existing wells in place.

**SAGD field description**

Cenovus Energy’s Foster Creek project began in 1996 and in 2001 became the industry’s first commercial SAGD project. Located in northeast Alberta, the field has more than 160 SAGD well pairs with daily bitumen production in excess of 100,000 bbl and an estimated recoverable reserve of 1.4 Bbbl. The bitumen at Foster Creek within the McMurray Formation exists between 1,542 and 1,804 ft TVD.

The SAGD process has proven to be an effective method of in-situ production of bitumen from the McMurray oil sands of Alberta. This process requires an injector and producer horizontal pair to be installed within the target formation. The injector is positioned typically 16 ft TVD above the producer and is used for the injection of HP/HT steam at approximately 4,532°F. Reduced viscosity bitumen and condensed water is collected in the producer and pumped to surface. TVD lateral separation between the injector and producer are important for optimal efficiency of the SAGD process and to minimize potential steam breakthrough to the producer.

A separation of 16 ft, +/- 3 ft TVD is critical for the process to work properly. Ranging systems are required to ensure this optimal separation is maintained while drilling the injector. Efficiency of the SAGD process is measured by the amount of steam injected for an equivalent volume of bitumen produced or the steam-to-oil ratio (SOR). Foster Creek’s SOR, at less than 2.5, is considered one of the best in the industry.

The length of the horizontal section can vary depending on reservoir characteristics or surface constraints but is generally between 1,640 and 3,281 ft. For proper production of the reservoir horizontal well pairs are positioned 328 ft laterally from one another. Multiple well pairs are drilled from a single pad to minimize surface disturbance and the amount of facility piping required. Pads typically have between four and 12 pairs. Cenovus Energy’s Pad W01 is in the western part of Foster Creek. The pad has a nine well-pair configuration which, due to surface constraints, required the pad to be offset from the horizontal sections. Each well consists of three separate sections, surface, intermediate, and horizontal.

The surface portion of the wells was drilled vertically with 17½-in. drill bits and cased with 13⅛-in. casing. The intermediate section was directionally drilled from vertical to horizontal with 12¾-in. drill bits and cased with 9⅝-in. casing. Build rates in the curve section of the intermediate hole were planned at 8° to 10°/100 ft. The horizontal section was drilled with 8¼-in. drill bits and completed with 7-in. liners. Conventional adjustable bent housing motors were used to drill the intermediate and horizontal sections. Gamma and inclination at bit also were used to determine directional response and maintain the horizontal sections in the optimum portion of the reservoir.

The GMWD system is used to provide an azimuth in areas of magnetic interference. It uses two sets of directional survey accelerometers to determine bending in the BHA. The alignment between the two sets of accelerometers must be known and can be measured on surface or derived downhole. The accelerometers also measure toolface so they can tell the orientation of the bending, hence the change in direction between the two sets. The initial part of the well is drilled like a normal well. Full survey data from both directional survey systems are required along with their dynamic Z values. This is required to perform full quality checks and possible corrections on the surveys. Corrections required from multistation analysis (MSA) and sag analysis are applied in real time. During the initial build and turn section, normal MWD surveys are used to define the well path. MSA and final calibration of the GMWD tool also are performed. Normal survey course lengths are maintained until the landing point, which is predetermined by the customer. There are actually two complementary passive ranging methods available during the landing of the injector well.

Passive ranging makes use of the static magnetic field inherent in metal, which in this project is casing that would normally have an unknown amount of magnetism imparted by magnetic particle inspection at the ends of the casing joint. This magnetism is localized and does not travel far from the casing.

Three things can be done to increase the magnetism from the casing to create a large magnetic target. First, the casing should be subjected to a very strong magnetic field over its entire length so the metal becomes nearly magnetically saturated. Second, the poles in the casing should not be too far apart as they would tend to act like mono poles. Third, if opposing poles are used, they tend to throw the magnetic flux further out from the casing. When these three things are done, the effective passive range is more than adequate for SAGD work.

The method can be validated by triangulation. The magnetic field around the casing is axially symmetric and flux lines loop around. These lines intersect in the middle of the casing determining its relative position. Validation of the ranging method can be accomplished at any location where there is a divergence, convergence, or crossing between the two wells.

There are special circumstances where the prior proce-
dures described need minor modifications, which occur when there is a possibility of drilling close to preexisting wells. This is possible when wells from the existing pad are relatively close to the end of a previous pad and when drilling infill producer wells. The new wells are often drilled several years after the existing wells and there is concern as to the accuracy of the well position. The solution, in this case, is to drill the new producer with the injector build well BHA, which allows the early detection of interference from an existing well via the use of GMWD.

When using RADAR to help accurately place the well pairs, the emphasis is on real-time, highly accurate decision making. The data must flow through the system with a minimal amount of user interaction. The specialized functions of the MWD/LWD operator, ranging specialist, directional driller, and driller are performed in a cooperative manner to achieve an optimal result. As each specialist completes their tasks, the results are automatically passed to the next function in the processing chain. There also is a satellite connection to a remote operations center to allow for consultation when needed along with continuous quality control.

Quality measures must be continuously available as time is critical. The results of the analysis, especially when variances are needed, must be clearly understood for consultation between stakeholders to be expeditiously carried out. Experience has shown that data analysis and decision making are usually best accomplished with a graphical display, especially when coupled with the backup ability to examine the values in detail in tabular form. This systematic approach allows the methodologies used in the various drilling phases to be provided via a consistent interface, simplifying the application of the positioning methodologies.

For SAGD, the focus of the producer well is on highly accurate well location and a smooth well bore. The accuracy and flexibility requirements lead to the necessity of using unprocessed sensor values as opposed to inclination and azimuth values evaluated in the tool. Adherence to a well plan, which may be modified based on geologic parameters, needs to be closely monitored and the directional driller should minimize the excursions from the nominal path.

The injector well plan needs to be reassessed prior to the start of the build section and the well drilled as carefully as the pro-
ducer. The goal is to minimize the corrections required during landing once the injector build section approaches the producer well bore close enough for ranging to be performed. The injector horizontal well plan is based on the actual producer surveys. The position of the injector well is continuously updated by ranging surveying and the directional driller is able to anticipate real-time changes as required.

**Fluid bypass sub**

Losing drilling fluid to the formation can be costly. Lost fluid is the first expense. Second, traditional methods of diverting lost circulation material (LCM) from the drillpipe to the annulus to mitigate lost circulation can be costly in terms of time. Fibrous and thick LCM can plug bit nozzles very easily and can damage MWD components or destroy a rotary steerable system. One way to avoid these problems is to install a circulating sub in the string above the BHA to protect those components by pumping LCM directly out to the annulus above the BHA.

Circulation subs are typically opened or closed by pumping a ball down the drillstring. The balls are forced through the tool to deactivate it and are collected in a ball catcher sub, which limits the total number of shifts the tool can achieve. Additionally, using traditional circulation subs can result in excessive time spent waiting for the ball to reach the tool, resulting in significant amounts of nonproductive time.

Circulating subs originally were “single-shot” iterations, which included a free sliding sleeve with a shear pin. When encountering a lost circulation zone, the crew would trip out of the hole and send the tool downhole. At a certain point when flow needed to be diverted, a ball would be dropped, pressure would build, and the tool would be activated. The tool evolved into a multiple shot sub, but it was still constrained by the number of times it could be activated. Each time the sub was to be activated, a ball would be dropped through the tool and would land on the seat. To deactivate the tool another ball or set of balls would be dropped to force the activation ball through the tool, where they would be collected in a catcher sub below the primary tool. And while it is a multi-use sub, there are limitations because of the ball catcher sub, which ultimately limits the number of times the tool can be cycled.

National Oilwell Varco (NOV) introduced its Multiple Opening Circulation Sub (MOCS) that allows unlimited cycling between porting to the annulus and flowing to the bit. The fluid bypass sub diverts 100% of the drilling fluid flow, or LCM in the case of curing lost circulation, to the annulus through two ports located 180° apart in the outer diameter of the sub. The key to the tool is the patented indexing mechanism that enables the tool to be shifted an unlimited number of cycles during each run. When the tool is needed for bypass operations, a single ball is pumped down the string and landed in the ball seat, creating a pressure differential across the tool. Once the minimum activation flow rate is achieved the piston is forced downward into the bypass section where 100% of the fluid is diverted to the annulus, at which point the BHA will not be exposed to anything pumped down the string.

“MOCS, like any of the other circulation tools, is initiated by a ball drop,” said David Herrington, product line director, Jars and Stroking Equipment for NOV. “But we also use our proprietary indexing mechanism that allows us to land a single ball on the seat. Thereafter, the tool can be shifted an unlimited number of times simply by cycling the pumps.

“When the driller shuts off the pumps, the piston returns to an upward or reset position,” he continued. “Our indexing mechanism shifts so that when the pumps are turned on, the piston lands in a secondary position, which leaves the ports to the annulus closed, and a secondary set of ports open that direct flow back to the bit.”

According to Herrington, “at this point, the cycle just repeats itself. Every time you cycle the pumps the tool shifts between bypass or flow to the annulus or to the bit.”

The MOCS is designed to operate in virtually any downhole condition. It is hydrostatically balanced and rated to 30,000 psi pressures, 5,000 psi pump pressures, and 450°F. The tool also has an open bore that, before the ball is dropped, allows for fishing operations should MWD components need to be retrieved. The drop ball is made of steel, and if an open bore needs to be reestablished for fishing after the tool has been activated, the ball can be retrieved with a special wireline fishing magnet that is included with the tool.

The MOCS tool can be used in a number of applications in various phases of drilling and completions. For example, the tool can be used to accelerate annular velocities in extended-reach horizontal applications to clean out low side cutting bed buildup. It also can be used to quickly and efficiently place kill weight fluids or circulate from the bottom up at the end of a run. The sub can be used in place of a wiper run or to clean out the BOP and riser by opening to the annulus and rotating while tripping out.

An important area where the tool has improved operations is in time and cost savings. "In a 15,000-ft well, for example, it could take 15 minutes to 20 minutes just to pump the ball down to the tool," Herrington said. "If you have to shift the tool five times between opening and closing, each time requires two sets of balls. That results in a minimum of 150 minutes just to shift the tool.”

In one comparison between a conventional circulation sub and MOCS, a crew using the MOCS shifted the tool 19 times to open and close the sub. That resulted in 10 complete cycles. Using an average of 15 minutes per ball drop on a conventional tool, the cumulative shifting operations would have taken over 3 hours. “We completed the shifting operations in a cumulative time of less than 30 minutes,” Herrington said.

Additionally, if an operator knows he will be encountering a lost circulation zone, the tool can be preloaded with the ball before running the sub and then activated and deactivated by turning the pumps off and on.