New technology creates a step change in drilling efficiency

At Alaska's Alpine field, drilling more than 70 horizontal wells produced a 17% efficiency gain and reduced costs, even as the wells became more complex

Chip Alvord and **Brian Noel,** ConocoPhillips Alaska Inc.; **Vern Johnson**, Sperry-Sun–Halliburton Energy Services/ConocoPhillips Alaska Inc.; **Ron Handley, David Egedahl** and **Eric Cribbs,** Sperry-Sun–Halliburton Energy Services; and **Lee Smith,** Security DBS–Halliburton Energy Services/Alaskan Energy Resources

Alaska's Alpine oil field has been developed exclusively with horizontal wells, and it has employed EOR to maintain average production of nearly 100,000 bopd over the past two years. Reservoir depths average 7,000 ft, vertical, with well depths ranging from 9,000 ft to 19,000 ft. Wells have become more complex and challenging as field development progresses, Fig. 1.

This well design change has driven the need for altered drilling practices. Accordingly, drilling in the 8½-in. intermediate hole section has evolved through three general practices:

1) Initially, two steerable BHAs were used, one (PDC bit) for the tangent section and the other (rock bit) for better directional control to land the curve.

2) Eventually, PDC bit design evolved to where it could drill the entire section in one steerable BHA run. Elimination of the additional bit trip, and the PDC bit's enhanced performance through the curve, saved substantial time and costs.

3) The section is drilled with one advanced-technology, "point-the-bit," rotary steerable drilling system (RSS) that uses extended-gauge PDC bits.

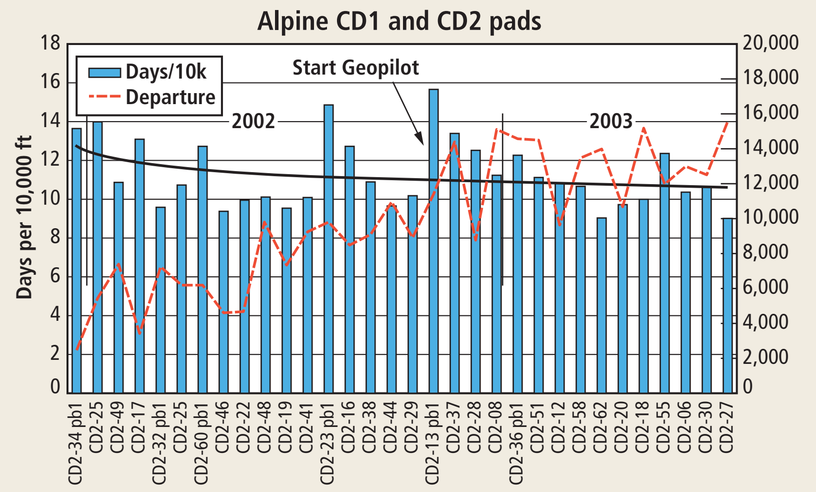

Fig. 1. The improvement in days per 10,000 ft drilled is clearly evident in this chart.

STEERABLE SYSTEMS

Combining a specially designed, extended-gauge drill bit with a new, proprietary RSS, Geo-Pilot, provides "point-the-bit" drilling, Fig. 2. Point the bit means that, unlike conventional systems and other RSSs that use side force to push the bit sideways, these systems tilt the bit in the desired direction.

This RSS design deflects a shaft between the bit and the drillstring. A high-side reference housing contains a compact, rugged, computer-controlled bias unit (eccentric rings) to deflect the shaft. This allows continuously variable steering, both by toolface and effective bend angle. Thus, downhole adjustment is possible for the drilling direction and the build rate desired.

Designed for use with extended-gauge PDC or roller cone bits, the RSS minimizes nonconstructive behaviors caused by short-gauge sidecutting bits. It eliminates hole spiraling, increases daily footage and improves directional control. This allows more precise wellbore placement while increasing drilling efficiency through improved hole cleaning, easier casing runs, fewer short trips and reduced drilling time.

Extended-gauge bit. A key RSS component is a specially designed, extended-gauge drill bit that is unlike previous short- or long-gauge bits. A long-gauge bit typically has up to 6 in. of gauge, but an extended-gauge bit's length is about one-and-a-half times the bit diameter.

The relative length to diameter of an extended-gauge bit provides long-gauge bit stability, ensuring a high-quality, spiral-free wellbore. However, the extended gauge requires densely packed, small cutters with high back-rake angles along the gauge to improve steerability. This avoids the short-gauge bit's strong side-cutting action in a conventional, push-the-bit approach for horizontal or deviated wells.

Applied in a point-the-bit drilling mode with an RSS, the extended-gauge bit can provide a smoother, maximum-drift directional wellbore without aggressive cutting that can harm steerability.

Also, the extended-gauge bit minimizes nonconstructive behaviors, maximizing ROP and directional control. It significantly increases bit, logging tool life and performance, and eliminates trips for bit and tool replacements.

Additionally, an important consideration is whether to use matrix- or steel-bodied extended-gauge bits. Each has specific advantages.

Previously, five-bladed matrix-body bits were used as the first bit run with the PDM. However, this requires water-base drilling fluid, and potential bit balling can occur. When the RSS was approved, the first decision was to use a steel-bodied bit. The pros and cons of steel-bodied PDC bits have been documented in earlier papers. As noted in the DEA90 study, high, normalized face volume is critical in reducing bit balling tendencies.

With the soft tophole section and high ROP expected, a steel-bodied bit provides flexibility for variable drilling paramaters, particularly flowrate. This reduces washout while cleaning the hole. By using a steel-bodied bit with a relatively low HSI (hydraulic horsepower psi, 1 to 2.5/3); high, normalized face volume; and an innovative nozzle/hydraulic system; it was possible to continue increasing effective ROP for the interval. This was achieved while maintaining directional control in very soft formations (ROP > 200 ft/hr to 250 ft/hr) and avoiding bit balling issues.

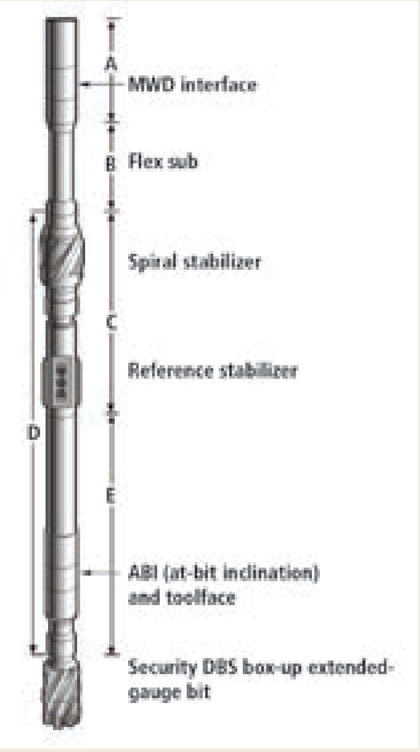

Fig. 2. Configuration of the rotary steerable drilling system (RSS).

OTHER CONSIDERATIONS

Numerous challenges associated with the remote Alpine location mandated rethinking of many drilling processes and functions. To facilitate a remote-site operational philosophy, the Alpine team assembled all of the contractors associated with drilling. Contractors were encouraged to combine efforts and equipment to minimize logistics and costs. This resulted in major modifications and significantly increased drilling efficiency.

The drilling rig. *DDI Rig 19* is a highly mobile drilling rig that works efficiently in extreme Arctic conditions. It consists of fully integrated, lightweight modules that can drill on 10-ft wellhead spacing. Mast hoisting capacity is 1 million lb, with a 12-line hookup. The cantilevered drill floor can handle a simultaneous, combined, 600,000-lb load for pipe set back, and a 900,000-lb rotary table load. The substructure can also move with over 300 kips of drillpipe, allowing immediate topdrive drilling. The rig is fully winterized, to support drilling operations to –50°F and 100-mph winds.

DDI was an early user of imported, 13.8-kv, high-line power. This on-grid capability greatly reduces emissions, and dramatically cuts fuel usage. The rig receives power from the central processing facility's gas-powered turbines via the pad production electrical supply. Turbine fuel gas is produced from wells at the pad, thus eliminating costly diesel fuel imports. If high-line power is not available, the rig can generate more than 6,000 hp of diesel power. This generally occurs when the rig wildcats away from Alpine's infrastructure.

Rig 19 can also move from well to well without disassembling separate components. This is because all the rig modules are self-moving on wheeled trailers. Thus, rig moves are made without expensive truck support or cranes—tear-down is eliminated. Typically, well-to-well rig moves from release to acceptance average 6 hr, a laudible feat compared to yesteryear. The rig substructure was replaced with a cantilevered design that can drill high-torque, extended-reach wells. Given pad size restrictions and ever-increasing step-out distances, the rig is well suited for future work.

To facilitate more Alpine exploration, a rig floor transportation device was invented for *Rig 19*. This device lowers the rig weight for pad-to-pad moves, decreases ice road costs, and eliminates large crane support. The unit allows the entire rig floor and derrick to be removed from the sub-base, and then lowered and transported in a separate, single load.

Another time-saving practice allows BOP equipment to remain assembled on well-to-well moves, including choke and kill lines. This allows crews to nipple up or down in minutes vs. hours. Another cost-saver is integration of a cuttings processing/injection unit for on-site fluid disposal. This eliminates on-site fluid-handling trucks and off-site cuttings processing. The module also has cementing units that replace call-out trucks.

TABLE 1. Intermediate hole, average ROP (from LOT to TD), including total hours (circulating & short trips)

RSS wells	Start depth	End depth	Footage	Total hours	Hours, correct	Avg. ROP
CD2-07	3,032	10,868	7,836	64.50	0.00	121.5
CD2-27	3,321	12,659	9,338	81.25	0.00	114.9
CD2-06	2,792	9,682	6890	73.50	0.00	93.7
CD2-18	3,253	12,124	8871	94.00	0.00	94.4
CD2-30	2,818	11,499	8681	83.25	0.00	104.3
CD2-55	2,810	12,220	9410	92.50	0.00	101.7
Per-well averages			**8,504.3**			**105.1**
Early RSS	**Start depth**	**End depth**	**Footage**	**Total hours**	**Hours, correct**	**Avg. ROP**
CD2-40	2,818	11,165	8347	177.0	80.50	86.5
CD2-37	3,105	14,173	11068	160.00	0.00	69.2
CD2-13PB1	2,946	10,541	7595	94.00	0.00	80.8
CD2-36PB1	2,708	15,558	12850	203.50	31.50	74.7
Per-well averages			**9,965.0**			**77.8**
Conventional wells	**Start depth**	**End depth**	**Footage**	**Total hours**	**Hours, correct**	**Avg. ROP**
CD2-12	2,667	8,,699	6032	102.25	14.25	68.5
CD2-20	2,674	9,178	6504	81.50	0.00	79.8
CD2-41	2,583	9,555	6972	98.00	0.00	71.1
CD2-15	2,666	9,840	7174	128.00	24.00	69.0
CD2-48	2,580	10,085	7505	124.50	16.00	69.2
CD2-29	2,682	9,566	6884	95.00	0.00	72.5
Per-well averages			**6,845.2**			**71.7**

TABLE 1a. ROP performance of RSS (on-bottom drilling only)

Latest RSS wells	Footage	ROP	Comments
CD2-52-2	9,780	208	Aggressive 5-blade
CD2-52-3	422	135	Aggressive 5-blade
CD2-55	9,410	159	Less aggressive 4-blade
CD2-40-1	7,697	192	Aggressive 4-blade
CD2-40-2	3,047	104	Aggressive 5-blade
CD2-30	8,483	175	Aggressive 5-blade
CD2-18	8,891	168	Aggressive 4 blade, some tougher drilling than usual
CD2-06	1,611	261	Aggressive 5 blade
CD2-06-2	5,279	149	Aggressive 5 blade
CD2-27	8,972	199	Aggressive 4 blade
CD2-07	7,826	194	Std/Agg 5 blade, Std/Agg 4 blade

Mud program. Lack of available space, and the cost involved to store base oil, eliminated synthetic and low-toxicity, oil based mud from consideration for the 8½-in., intermediate hole interval. Fresh water from nearby lakes is available year-round. A low-solids, non-dispersed (LSND), freshwater drilling fluid was ultimately chosen. This was because of its relatively low-cost, minimal maintenance requirements; suitability for formations drilled; and relative ease of on-site waste handling.

Mud weights in the intermediate hole section range from 9.6 ppg to 10.0 ppg. Fast drilling through soft, shallow clays can cause hole washout (affecting body roll with the RSS), bit/BHA balling and hole cleaning issues. However, maintaining turbulent flow around the BHA with lowered fluid rheology has helped mitigate balling and poor hole cleaning.

To save time, 4-in. pipe is used to drill the 8½-in. intermediate and 6⅛-in. production intervals. Pump pressure limitations sometimes occur with longer departure wells. Extensive hydraulics modeling optimized fluid rheological properties and achieved minimum drillstring pressure drop. This was achieved while maintaining good hole cleaning and ECD control.

The HRZ and Miluveach shale sections above the Alpine sands can become unstable, especially at higher hole angles. Typically, higher mud weights and treated asphalts are used to stabilize these shales. However, due to low pore pressure in some Alpine sands, mud weights must be controlled, or lost circulation will result. A glycol-based fluid additive has effectively increased shale stability and allowed lower mud weights.

Within Alpine's oil production, formation pressures have dropped significantly in areas lacking injection support. Lost circulation in the under-pressured sand has been experienced while drilling and running/cementing 7-in. intermediate casing. Keeping mud weights below 9.8 ppg, while minimizing ECD and adding particle-sized, graphite-based plugging material, can help mitigate losses.

PERFORMANCE

Data show that in Alpine's first three years, 44 wells averaging 12,788 ft were drilled in 13.85 days per 10,000 ft. Over the last two years, 32 wells averaging 14,102 ft have been drilled in 11.46 days per 10,000 ft. This represents a 17% increase in efficiency for wells that average 10% longer. Improvements are summarized in Fig. 1 and Tables 2 and 3.

For the first 10 months of 2003, even longer wells (16,216 ft) were drilled in an average 11.2 days per 10,000 ft. Specifically, the 8½-in. interval, which can exceed 10,000 ft, is drilled with the RSS. This allows use of 4-in. drill pipe in the 8½-in. and 6⅛-in. hole sections. Latest performance data available are shown in Table 1, with Table 1a showing the increased ROP of RSS runs when calculated with drilling hours, only.

RSS is not powered by a motor. So, in some cases, performance decreased when switching from a conventional motor to a rotary steerable model. However, Table 1a shows the consistent improvement gained by using RSS. It has increased ROP from 135 ft/hr to more than 200 ft/hr.

TABLE 2. Performance comparison: Push the bit vs point the bit

Well	ROP, ft/hr	ROP, days/10K	Hole section, days/10K
CD2-33 push the bit	106	3.393	8.41
CD2-24 push the bit	121.5	3.43	5.92
CD2-37 point the bit	164	2.54	6.90
CD2-38 point the bit	135	3.09	6.88

TABLE 3. Alpine days/cost by year

Year	No. of wells	Avg TMD, ft	Avg days, drill & complete	Avg. cost/ft	Avg. days per 10,000 ft	% NPT
1999	12	11,741	18.4	228.8	15.7	10.5
2000	22	13,290	17.0	209.9	12.7	7.5
2001	10	12,940	23.3	307.1	14.2	11.7
2002	19	12,559	17.1	249.4	11.6	7.8
2003	13	16,358	20.8	244.4	11.2	14

Bit design. Initially, the RSS was run with an 8½-in., five-bladed bit and ¾-in. cutters. This steel-bodied bit has a force-balanced design with asymmetric blade layout and spiraled blades, as well as tracking cutters. Designed for enhanced stability in directional situations, the bit has advanced cutter and nozzle technology for faster drilling while maintaining durability. This standard bit was used in a number of early wells, successfully drilling 11,196 ft in one well, and achieving a 164-ft/hr (high) ROP in another.

In what was the longest, single run to date, the RSS ran with the five-bladed bit. It directionally drilled a build-and-turn profile, to TD one well at 14,173 ft after about 70 hr of drilling time. Last-minute geological changes in landing at TVD were handled. The bit was pulled, in very good shape, after 11,068 ft.

At 12,067 ft, a planned wiper trip began, back to the shoe. The hole was rather tight, to about 9,800 ft, and had to be washed and backreamed to that depth (and in several other places). At this point, the RSS had cut 9,000 ft in 55 drilling hours and 44 hours of circulation.

After this short trip, the assembly drilled to a 13,100-ft depth. At this point, the build-and-turn was initiated, with 1,000 ft to go. The RSS tool was set at 60% deflection, and it performed excellently, cutting 10,000 ft in 61 hr of drilling and 50.3 hr of circulation.

Design change. As performance leveled out over the next several wells, the bit design was revised with reduced backrake on the cutters, to make it more aggressive and increase ROP through the run. On the next well, the new design drilled float equipment and the tangent section at 57°, then it built to horizontal at the casing point. The entire 8½-in. interval was drilled at an ROP of 181 ft/hr, the fastest average, to date, for Alpine.

Following that successful run, the bit was rerun in a second well, establishing another new record penetration rate at an average 208 ft/hr. The bit drilled float equipment and the tangent section at 45°. In three runs, it achieved cumulative footage of 18,891 ft in 97.38 hr, for overall average ROP of 93.99 ft/hr.

Recent performance. A change in bit design from five to four blades yielded more aggressive performance, when an 8½-in., four-bladed bit was run in to drill 7,697 ft, at average ROP of 192 ft/hr. This bit has been rerun in a recent well (CD2-27), drilling 8,972 ft at average ROP of 199 ft/hr.

As of this writing, the CD2-07 well, while drilling ahead at 9,985 ft on the way to 10,943 ft, had drilled 6,851 ft in 32.1 hr of drilling time and 19.8 hr of circulating time, for an average ROP of 213.5 ft/hr. The 8½-in., intermediate RSS run began two days earlier. Bit jets were opened up to 16s, to limit hole washing and subsequent housing roll in the first 1,000 ft +/- of hole.

A rig report indicates this run started at 3,042 ft, MD, from under the 9⅝-in. shoe. The housing roll experienced when drilling out of the casing shoe was not as bad as usual. It seemed to clear up sooner than expected, i.e., at 3,700 ft, TVD, rather than 4,100 ft, TVD. At this writing, drilling ahead is proceeding on target with only small corrections.

Well statistics now show 3,968 ft drilled in 18 hr, for average ROP of 220 ft/hr. Operating parameters include rotary torque of 8-12K; WOB of 20/25K; rpm at 150 and a 650 gpmk flowrate. [Note: This 8½-in. intermediate run was completed with RSS, exhibiting excellent performance, using these parameters at casing point TD: depth, 10,868 ft (TVD, 7,103 ft, RTE); a 7,826-ft interval drilled in 40.4 hr, for average ROP of 193.7 ft/hr. Operating data were WOB, 15/20K; torque, 14.5 kft-lb off, 16.5 while drilling; and a 550-gpm flowrate.]

LESSONS LEARNED

The system approach to optimization significantly reduced drilling time for intermediate hole, even with the increased complexity of some wells. A consistent team and drilling program allowed for a steep learning curve, and the ability to increase efficiency in all drilling disciplines.

Effective ROP and system limitations. One must understand and maximize the entire RSS, to achieve higher ROPs throughout the interval. Factors that must be varied to optimize performance include flowrates, operating parameters, mud properties and HSI. Continual HSI reduction allows greater performance to be achieved in key intervals.

Bit selection and design. Understanding and optimizing bit design is important for maintaining system performance. Bit design variables can be controlled more easily than some other factors, with the goal being to remove the bit from the system's "limitations."

In the key interval from 8,000 ft to 11,000 ft, bit design changes were made cautiously, to prevent instances where the RSS would be pulled, due to bit performance. Subtle changes to the five-bladed design increased ROP before the four-bladed design was introduced.

One risk in using a four-bladed design is failure to complete the full interval. Once baseline performance and dull condition were established, the design was enhanced to push ROP higher. Design changes included varying bit profile, blade count, nozzle type and cutter size. To date, no assembly has been pulled for bit performance, and no bit has failed to complete the full interval.

Steerable system advantages. Use of the Geo-Pilot rotary steerable system resulted in several benefits, as detailed in the following paragraphs.

Reduced time for handling drill pipe. With the increased step-out and length of the intermediate hole section in these wells, stand pipe pressure (SPP) using 4-in. drill pipe limited flowrates near sectional TD. Additionally, when utilizing a positive displacement motor (PDM), the additional stall pressure would have to be considered and allowed for, further reducing operational flowrate. Thus, to successfully drill the higher departure wells, 5-in. pipe was required to reduce frictional losses and allow for a higher flowrate near TD. The following 6⅛-in. hole section required 4-in. pipe.

This RSS has no stall, so no additional pressure must be allowed for when considering hydraulics. Considerable time and cost accrued from picking up and laying down two strings of drill pipe. Utilizing the RSS made it possible to use 4-in. pipe for both the intermediate and production hole sections.

Short trip elimination. Historically, the first several thousand feet of intermediate hole are drilled through soft clay. These soft, sticky clays tend to pack along the borehole wall, reducing the wellbore gauge and increasing ECDs. Neither flowrate nor rotation of drill pipe *was* effective in removing this material. What was effective was a wiper trip with backreaming through the section. Once the section was effectively wiped clean, it no longer posed any difficulty.

With the RSS, the constant, higher drillstring RPMs created more effective hole cleaning. It also allowed the opportunity to run a tool (string reamer) in the drillstring to remove the clay buildup while drilling, rather than dedicating a short trip for that.

Better ECD control. Oriented drilling for directional control in highly deviated wellbores brings the following operational drawbacks:

- Oriented drilling with a steerable assembly typically results in slower ROPs and poor hole cleaning.
- When drilling begins, cuttings that have settled to the hole bottom are stirred, raising ECDs. Increased ECDs require holding back ROP while rotating, until ECDs return to allowable limits. This RSS always rotates when drilling, allowing for more effective hole cleaning and consistant ECD control.

Reduced torque and drag. Drilling a smooth, non-spiraled wellbore results in reduction of measured torque and drag, both in the intermediate hole and the subsequent lateral section. Achieving a smoother intermediate hole allows longer laterals with more effective slides to geo-steer through thinner pay on the edges of the field.

ECONOMIC ANALYSIS

Economic analysis estimates savings over the remaining 20 planned wells to exceed $4 million, based on two days of saved rig time vs. comparable well type/length. Overall rig uptime (more than 99%), state-of-the-art equipment, and the combination of many individual efforts into one seamless operation, have resulted in wellbore construction costs that are the envy of the North Slope. **WO**

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THE AUTHORS

Chip Alvord is the Alpine Drilling Team leader for ConocoPhillips Alaska Inc. He earned his BS degree in mechanical engineering from the University of Maine in 1981. He has worked a number of drilling and production assignments throughout Alaska and in Indonesia, and he is working on a number of development scenarios for Alpine and NPRA satellite accumulations.

Brian Noel is senior drilling engineer at ConocoPhillips Alaska Inc. He earned his BS degree in geology from the University of Illinois in 1977 and his BS degree in petroleum engineering from the University of Wyoming in 1991. He spent 11 years as a well site geologist in the northern Rocky Mountains and has worked drilling and production engineering assignments.

Vern Johnson is a drilling engineer for ConocoPhillips Alaska Inc. He earned a BS degree in mathematics in 1992, and a BS in mechanical engineering in 1995, both from Dalhousie University. His work in the Middle East and Alaska included MWD, LWD and multilaterals.

Ron Handley is directional drilling coordinator for Sperry-Sun, Alaska. He holds an MSc from the University of Alberta. Formerly a naval officer and teacher, he has 17 years of drilling experience.

David Egedahl is an engineering manager for Halliburton/Sperry-Sun in Alaska. He earned a BS degree in petroleum engineering from Montana Tech. He has 15 years of industry experience, working in the Gulf of Mexico, Texas and Louisiana land, Permian basin, Mid-Continent, Rocky Mountains and Alaska (North Slope and Cook Inlet). Mr. Egedahl has held positions as field engineer, operations coordinator and directional drilling engineer.

Eric Cribbs is Sperry-Sun's MWD/LWD coordinator. He earned a BS degree in Petroleum Engineering from the University of Alaska, Fairbanks, in 1994. He has worked as a field engineer and field supervisor.

Lee Smith is president of Alaskan Energy Resources, Inc., an agent for Security DBS–Halliburton Energy Services, providing sales and support to Alaskan operations. He holds a BS degree in geology from the University of Utah and an MBA from Oklahoma City University. He has more than 25 years of experience, including a number of domestic/international operations and marketing management positions.