

Next Generation of Sakhalin Extended-Reach Drilling

Six of the longest-reach wells in the world have been drilled in Chayvo field on Sakhalin Island. Revised completions used standalone screens (SASs), pre-drilled liners, and swell packers to achieve a low-damage, sand-free completion with zonal isolation. Bit designs, bottomhole-assembly (BHA) configurations, and operations practices were modified to minimize the amount of backreaming, improve the overall rate of penetration (ROP), and achieve a "one-pass trippable hole" (OPTH). Improving rotary-steerable-system (RSS) reliability could eliminate trips to replace the tools.

Introduction

The Chayvo field development plan comprises 15 onshore extended-reach-drilling (ERD) wells with measured-depth (MD) reaches of 8 to 10 km and 18 offshore directional wells drilled from an ice-resistant platform. The focus of this paper is the Chayvo onshore ERD operations that began in July 2003. At the time this paper was written, eight of the 15 land-based ERD wells had been drilled from the Chayvo wellsite (**Fig. 1**). The full-length paper details design changes and operations optimization that evolved into the next generation of ERD wells at Sakhalin. The typical Chayvo ERD well design is shown in **Fig. 2**.

Completion Design Evolution

The original completion design met the following objectives.

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Fig. 1—Aerial view of Chayvo onshore well pad.

- Low-damage completion capable of producing 25,000 BOPD.
- Providing zonal isolation to mitigate risk of gas and/or water breakthrough.
- Sand-free completion.
- Provide low-risk interventions.

The first four Chayvo completions were designed to achieve these objectives by use of a rotated and cemented 7-in. liner tied back with 7-in. tubing. These 7-in. monobore completions enabled oriented underbalanced perforating with coiled tubing, thereby reducing potential for sand production and providing a low-skin completion.

Although this design achieved all the objectives, implementation proved difficult because of liner-cementing and perforating problems. Running the 7-in. liners on the first four wells was trouble-free. However, problems occurred in two wells while filling the liner with mud, and the other two wells had cementing problems.

Redesign. Completion redesign focused on reducing nonproductive time (NPT) caused by failures in the liner installation and problems with perforating. Design options included openhole completion, openhole gravel pack, cased-hole gravel pack, and SAS. **Fig. 3** compares the new and old completion designs. The new design uses external-isolation swell packers and SASs with inflow-control devices (ICDs), which were not proven or available for the original completion designs. The new design positions SASs across the weaker, more permeable formation to provide a sand-free completion. These SASs use ICDs (or chokes) to reduce flow from the high-permeability formations that could produce gas or water if allowed to produce unrestricted. The high-permeability intervals are isolated from the low-permeability intervals with swell packers. The higher-strength low-permeability intervals are completed with a predrilled liner. Swell packers replaced cement for zonal

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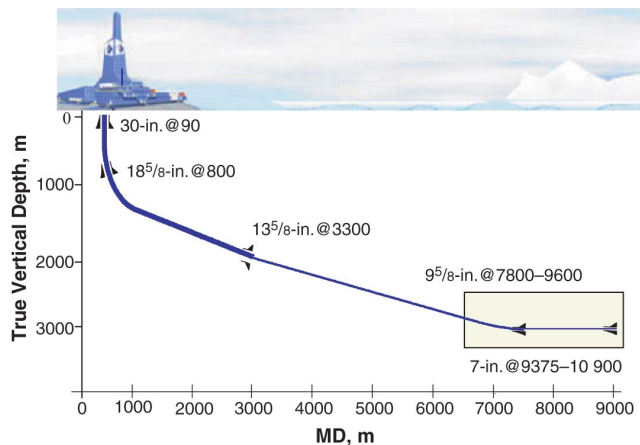


Fig. 2—Typical Chayvo well-plan schematic.

isolation, and ICDs replaced selective perforating to control flow from high-permeability zones. The key to successful zonal isolation was positioning swell packers and screens precisely across the high-permeability zones.

At the time this paper was written, two of the new completion designs had been installed. On the first well, production logs were run to verify that swell packers were isolating the annulus and that flow was being restricted by the ICDs (as predicted) with half of the production from the high-permeability sands. No sand production was detected at surface or downhole. The new completion achieved all of the design objectives at half the cost of the previous design.

Continued performance improvements at Sakhalin required a focused effort to optimize the design and challenge standard operating practices. A team comprising operator and directional-drilling engineers analyzed data from the first six wells and developed recommendations. The 12¹/₄-in. hole section was chosen because it represented the longest section of the ERD wells in both length and time to drill. Successes in the 12¹/₄-in. hole section could be translated to other hole sections of the well upon validation.

OPTH. This practice is defined as tripping with the elevators after drilling a hole section to total depth (TD) without short tripping or increasing the risk of stuck pipe. Backreaming and short tripping was a major cost and risk driver on the first two wells; therefore, eliminating these operations was a critical goal.

The first two wells were backreamed full stands on connections but were not backreamed on trips, then backreamed

coming out of the hole before running casing. By the sixth well, backreaming on connections was reduced to 5 m, but backreaming on trips had increased dramatically.

Backreaming on trips was, in part, a response to tight spots that occurred on previous wells. Another goal while backreaming on connections was to reduce the cumulative shocks on the RSS tools that led to premature failure. Typically, a minimum amount of backreaming was required on connections and was believed to move cuttings above the BHA. Overall, the cost of backreaming was not reduced in the first six wells.

Analysis of trip data revealed that 95% of the tight spots and all six stuck-pipe instances were not caused by a cuttings bed but occurred at “hard knots” or “concretions.” Concretions are hard, compact accumulations of mineral matter, usually spherically or disk shaped, that form inside sedimentary rocks. The concretions are between 0.1 and 3 m in diameter and drill at 1 to 3 m/h, whereas the surrounding formation drills at 50 m/h. These learnings led to new tripping practices that assumed tight spots were caused by bit darting and not by cuttings accumulations.

In addition, stiffer rotary-steerable BHAs showed a higher tendency to encounter tight spots or get stuck. Analysis of the six stuck-pipe instances showed that all were freed by either jarring or pulling up. These learnings led to customized practices for drilling and tripping at Sakhalin.

Improving ROP. Initially, a self-imposed instantaneous-ROP limit of 30 to 35 m/h was established to ensure optimum hole cleaning. This limit was based on experi-

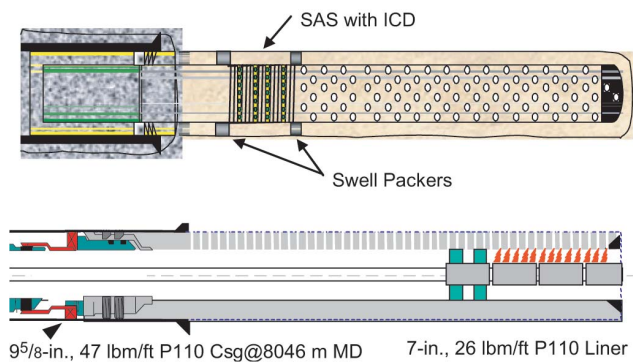


Fig. 3—New (top) and old (bottom) completion design.

ence gained in other ERD wells and was to ensure that, while drilling, cuttings-bed accumulations would not develop and cause stuck pipe. Implementing ExxonMobil’s Fast Drill Process removed this limit. This work process maximizes ROP in every meter of hole drilled by maintaining weight on bit (WOB) just below founder and by continuously redesigning to extend or eliminate ROP limiters. A key to implementing the process is quantifying the risks associated with higher ROP. The Sakhalin team developed goals to increase instantaneous ROP incrementally until new ROP limiters were found.

One key to successful implementation was reducing vibration at the bit. This ROP limiter was known from shock data from the RSS. To reduce vibrations and increase ROP, the bit gauge length was extended from 5 to 8 in. The increased gauge length was expected to reduce bit darting that was occurring when drilling the concretions. To improve the understanding of downhole vibrations, especially while drilling concretions, a downhole dynamic subassembly was run. Well Z3 had a 50% increase in instantaneous ROP while drilling concretions because of the increase in gauge length and implementation of the work process.

Another limiter was shale-shaker capacity. Efforts are under way to improve the efficiency of the shakers and determine if additional equipment can be justified. Bit manufacturers’ published WOB ratings were found to be a limiter, especially when drilling concretions. The basis for WOB limitations currently is under discussion with bit manufacturers to understand failure mechanisms and risks. The auto driller

was found to be an additional limiter because it could not keep up with the rapidly changing conditions required to optimize ROP. Although hole cleaning was reduced with increased ROP, it was not found to be a limiter.

Another ROP improvement was gained with a change in the well path to reduce the amount of footage drilled through the interval where concretions occurred. Because concretions could be drilled at only 2 to 3% of the rate of surrounding formations, minimizing drilling through this interval would increase ROP.

RSS Improvements

Drilling each hole section with one BHA is the goal for rotary steerable at Sakhalin. Achieving this goal will require improved reliability and fit-for-purpose equipment. Trips to replace BHA components in Sakhalin ERD wells require up to 6 days. RSS reliability and run times on the early wells were below expectations. The first well required nine BHAs to drill the 12¹/₄-in. hole section. On each subsequent well, the number of required BHAs was reduced, with a recent 12¹/₄ in. hole being drilled with only two BHAs.

Initial improvement in RSS performance was the result of root-cause analysis. All failures were analyzed, and solutions were implemented. An example is that components in the RSS were failing because of fluid erosion. These components were not designed to last for the duration of the runs required at Sakhalin. Investigation showed that a fit-for-purpose design could improve both erosion resistance and life of the component.

Downhole Vibration. Another key to obtaining the goal of one BHA per hole section was reducing downhole vibrations that shorten RSS life. Downhole vibrations also have been shown to reduce instantaneous ROP performance. To reduce vibrations, a downhole-dynamics subassembly was run to obtain a better understanding of the causes of vibrations. The subassembly measured whirl, bit bounce, stick/slip, WOB, torque, and bending moment. The downhole subassembly provided comprehensive data for real-time and post-job analysis of drillstring dynam-

ics. Drilling parameters were varied, and vibration levels were recorded. This process enabled development of drilling practices to reduce vibrations.

The downhole subassembly WOB was typically 12 to 15 kips lower than the surface WOB when drilling the concretion-free sections, but the separation between downhole and surface WOB was small when drilling concretions. These learnings enabled developing correlations between surface and downhole WOB and torque for use in future wells.

For drilling concretion sections, the procedure involved deactivating the automatic driller, increasing the WOB, and not allowing drill-off. Higher rotating speed and flow rates were maintained during this process. The ROP before drilling the concretions with this method averaged 3.6 m/h; the new process achieved 6.3 m/h. This new process of drilling concretions reduced vibrations dramatically. However, drilling concretions required constant driller's attention to minimize vibrations because whirl could start at high rotating speed.

Casing Installation

The initial design called for floating (or partially floating) the 13⁵/₈- and 9⁵/₈-in. casings and fully floating the 7-in. liner when running in hole. In addition, the design included rotating the 9⁵/₈ in. casing and 7-in. liner if necessary to get to bottom. Concerns with wellbore stability, lost returns, and cuttings-beds issues were addressed in the design of the casing strings and running operations.

Flotation, or partial flotation, was used to ensure success on the initial Chayvo ERD wells. Because of the additional cost and time associated with these operations, it became a team goal to eliminate flotation where possible.

The first two 13⁵/₈-in. casing strings were run with mud-over-air flotation to ensure that the casing reached TD. However, running mud-filled 13³/₈-in. casing showed that the friction factor was low and showed a final slackoff weight of 300 kips. No problems were encountered while running the casing.

The typical 9⁵/₈-in. casing string was run to 8200 m MD with the last 200 to 300 m being horizontal. Roller centralizers were effective in reducing friction

during the casing installation. The number of roller centralizers was reduced with a corresponding reduction in friction factor. The mud-over-air method was used to run this string of casing.

Liner. The 7-in.-liner installations occur in the horizontal section and are planned for up to 3200 m of 8¹/₂-in. open hole. Initially, the liners were floated in and rotation was required to get liner to bottom. Specialized centralizers with rollers to reduce both slackoff and rotating friction were used. The liner is made of high-collapse casing to resist the high static and surge loads encountered while running the liner.

The first four liners were floated and run to bottom with only minor difficulty. However, cementing or filling with mud proved difficult, if not impossible. Circulation could not be established on the first liner after it was filled. The second liner collapsed (or twisted off) while being rotated and filled on bottom. The third liner had to be cemented without use of drillpipe- or liner-wiper plugs when the landing subassembly failed to trip to the full-open position. The fourth liner had cement set up inside the entire liner.

The new completion design prohibits flotation of the predrilled liner and screens. The possibility still exists that the drillpipe could be floated with the liner filled with mud; however, this equipment increased the mechanical risk of executing the job. After reviewing data and well files, it was decided to run the liner and drillpipe mud-filled.

Conclusions

Chayvo ERD well costs have been reduced by 40%, comparing the average of the first four wells with the last four wells. Most of the cost reduction came from completion-design changes that reduced NPT and eliminated the costly perforating and liner-cementing operations. The drill team has been able to reduce time to drill the wells dramatically with a focused effort on time and cost reduction. The improvements are a result of focusing on the work process, achieving OPTH, eliminating flotation of liners and casing strings where appropriate, and improving the run time of rotary-steerable tools. **JPT**

