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# Integration and new technologies save $1.6 million in deep water

Drilling and sand control synergies improve well delivery efficiency for a challenging high-temperature well offshore India.

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The success of a sand control strategy depends on proper selection of drilling fluids for effective filtercake deposition and hole conditioning; screens, fluid systems and pumping designs for efficient packing of the treatment interval; and, if necessary, a filtercake breaker system to aid in filtercake cleanup, thus minimizing skin. In conventional practice these interdependent technologies have often been seen as discrete components, but as drilling and completion complexity increases, a holistic approach can significantly improve efficiency and effectiveness of well delivery.

By integrating technologies to rejuvenate a critical but challenging deepwater gas well in India, engineers were able to plan ahead to avoid complications that would otherwise have hindered the efficiency and effectiveness of drilling and completion operations.

## Restore production for a depleted gas well

A gas well in the deep water offshore India drilled in the mid-2000s was declining rapidly because of sand and water production and reservoir pressure depletion. In 2016 Schlumberger proposed to improve recovery from the well with an integrated drilling and completion strategy that efficiently combined drilling fluids and sand screens as well as completion and filtercake breaker fluids.

As a first step, the original wellbore was abandoned and a sidetrack drilled from the 13⅝-in. casing for a new cemented 9⅝-in. liner followed by drilling an 8½-in. production hole. The new well was designed with a maximum deviation of 87 degrees, with a deviation of 65 degrees through the reservoir. The openhole section was estimated to have a fracture gradient of 0.54 psi/ft and bottomhole static temperature of 113 C (236 F).

The depleted reservoir and low fracture gradient in the openhole section posed a significant challenge for the drilling operation. Offset wells had suffered catastrophic mud loss even though the mud equivalent circulating densities were less than the predicted leakoff test values. In addition, higher fracture gradients in the overburden shales created a potential risk for wellbore stability issues.

To minimize formation damage while ensuring openhole integrity for later gravel-packing operations, engineers recommended the VERSAPRO invert-emulsion reservoir drill-in fluid system. To minimize losses, engineers tested several lost-circulation materials for use in the system. Only the acid-soluble SAFE-CARB ground marble bridging agent achieved an acceptable return permeability and was therefore chosen for use in the well.

A wide particle size distribution in sizes from 2 µ to 1,400 µ was engineered specifically with the aim of effectively plugging fractures and faults that led to losses in offset wells. Laboratory tests indicated that the final mixture was able to bridge and seal existing or induced fractures up to 1,500 µ with less than 250 ml of effluent. No mud loss occurred during drilling, an unprecedented achievement for the selected formation. Compared with average losses in three prior wells drilled in the formation, the engineered mud system saved the operator more than $1 million on mud and rig costs.

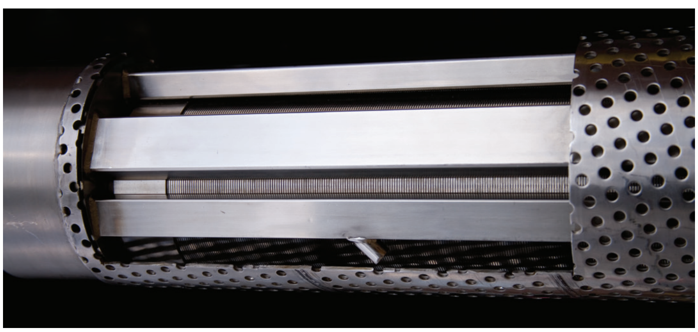

**FIGURE 1. The OptiPac Alternate Path sand screen uses shunt-tube technology modified for openhole gravel packing to optimize gravel-packing efficiency regardless of conditions that can lead to premature screenout. (Source: Schlumberger)**

## Eliminate losses and achieve complete annular pack

The next challenge, however, was to complete the well and achieve a complete gravel pack if

GRAVEL-PACKING TREATMENT

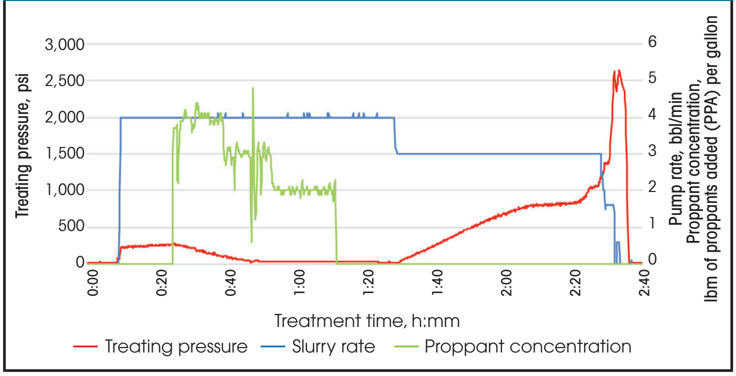


**FIGURE 2. ClearPAC HT fluid was used to ensure proppant transport during the gravel-packing operation. Shunt activation of the OptiPac screen (an increase in treating pressure and drop in slurry rate), seen at the end of the treatment, ensured a complete annular pack. (Source: Schlumberger)**

losses occurred while packing. To ensure complete packing of the openhole annulus, engineers recommended using OptiPac Alternate Path openhole gravel-pack screens. Alternate Path technology is licensed from ExxonMobil Corp. exclusively to Schlumberger and uses shunt tubes and nozzles to bypass bridges and fill in voids that can occur when gravel-packing (Figure 1).

To minimize solids production that plagued the earlier well, engineers recommended a 200-µ direct-wrap screen. However, the integrated team recognized this choice would carry a high risk of plugging without thorough mud conditioning and fluid compatibility assurance. Extensive laboratory testing was conducted to verify mud screening capabilities and mud compatibility with water-based viscous spacer fluids, a new high-temperature gravel-pack carrier fluid and the most efficient filtercake cleanup fluid system.

Surface lines, pumping equipment and pits were cleaned thoroughly during the well operations, and mud was prescreened offline before displacement, saving time on the mud conditioning operation. The well was then circulated to achieve consistent, positive production screen test results for 6 liters of mud over a 200-µ screen coupon—a criterion that exceeds industry standards and which the operator considered critical to minimize the risk of plugging the screen.

Viscous brine cleanup pills were used to help achieve targeted total suspended solids of less than 0.05% and turbidity less than 40 nephelometric turbidity units.

An anti-swab service tool also was deployed as part of the completion in this well to maintain pressure balance, minimize the risk of early filtercake removal and improve operational flexibility for gravel packing and subsequent filtercake cleanup.

## Carry gravel in a high-temperature well

Due to the narrow fracture pressure window and concerns of gravel settling in the long horizontal workstring section, the operator had originally planned to pump the gravel-packing treatment at a low rate using an ultralightweight proppant. However, due to unavailability and high cost, the ultralightweight proppant was not considered, and the operator elected to use conventional ceramic proppant. To minimize formation damage, the operator planned to use a conventional viscoelastic surfactant carrier fluid. However, laboratory testing determined that at the expected reservoir temperature a conventional viscoelastic surfactant fluid system was unable to adequately transport the proppant at the low pump rates required to avoid fracturing the formation.

Instead, Schlumberger recommended the new ClearPAC HT polymer-free high-temperature gravel-pack fluid, which has gravel suspension properties for conventional ceramic proppants at bottomhole static temperature between 93 C and 149 C (200 F and 300 F). In addition, this fluid is compatible with divalent brine such as calcium chloride ($CaCl_2$) brine, which was the planned brine for this well. Using this fluid with ceramic proppant saved the operator about 45% of the gravel cost compared to ultralightweight proppant (Figure 2).

On the drillship the fluid was prepared in 9.3-lb mass (lbm)/gal $CaCl_2$ brine using skid-based mixing equipment. The openhole gravel-packing treatment was successfully pumped at 3 bbl/min to 4 bbl/min with 30:50 ceramic proppant at concentrations from 2 lbm to 4 lbm of proppant added. Based on proppant volume pumped, hole size and memory gauge analysis, the treatment achieved a 100% annular pack. Mass balance calculations also determined that no gravel had settled in the long horizontal workstring section.

After the gravel-packing operation the anti-swab service tool was converted to wash-down mode for pumping the engineered MudSOLV filtercake removal service, saving about $450,000 on rig time by eliminating the need for an additional run. The well was shut in for three weeks, and when it was put online it met the target production.

Integrating both drilling and completion operations improved logistic efficiencies and reduced nonproductive time and overall cost by $1.6 million. E&P