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A Comprehensive Approach for Drilling and Completion to Improve Production in a Shallow, Off-shore Well in Indonesia

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Abstract

The Tunu field, located in the swamps and shallow waters of the outer margin of the Mahakam delta, is a gas and condensate field in east Kalimantan, Indonesia. Because of the low incremental reserves per well, the field development team was challenged to either reduce the cost of developing and operating the well to achieve target economics or to increase producibility. In this case, the operator was able to achieve both.

Gas-bearing reservoirs, found from 2,200 to 4,000 m, are known to contain sensitive shales. Consequently, synthetic oil-based drilling fluid has traditionally been used for drilling the reservoir, followed by the installation of a gravel pack completion for sand control. Significant costs associated with the handling and disposal of oil-based mud cuttings are also eliminated through the use of water-based muds. The operator's goals for this particular well included altering the completion design to standalone screens and drilling with a highly inhibitive water-based drilling fluid to protect the reservoir while reducing cost. To achieve these goals, a rigorous fluid design program was implemented to evaluate shale inhibitors and optimize the formulation to ensure that no issues would be encountered while running in the standalone screens. The selected drilling fluid contained a novel blend of shale inhibitors with an optimized bridging and fluid compatibility; it was specifically tailored for the Tunu reservoir.

This paper discusses the design of an enhanced drilling fluid that prevents formation damage in sensitive shales and facilitates a simpler and more economical completion method, which reduces costs and improves production.

Introduction

Formation damage costs operators millions of dollars annually in reduced production and/or injection relative to original predictions made before beginning a drilling campaign. This 'hidden cost' can be attributed to many factors during the drilling and completion phases.

The process of engineering drilling fluids to minimize formation damage is time consuming but an ultimately valuable process. Several elements should be considered when designing a fluid for a specific reservoir, including the following:

- Shale inhibition
- Bridging across the reservoir
- Completion design compatibility

This last point, completion design compatibility, is a critical element with regard to successfully running optimally designed completions to maximize returns from the well. Standalone screens are susceptible to plugging by particles contained within the drilling fluid; a gauge hole is drilled and maintained to help ensure that screens can be run to the desired total depth.[1, 2]

Several drilling fluid formulations with a specific gravity (sg) of 1.15 were mixed and evaluated for their suitability to drill and complete the Tunu reservoir; this evaluation placed particular emphasis on shale inhibition, fluid loss, and particle size distribution.

Experimental

Before drilling the well, several types of tests were performed, including shale testing, particle size analysis and bridging capability, and completion compatibility.

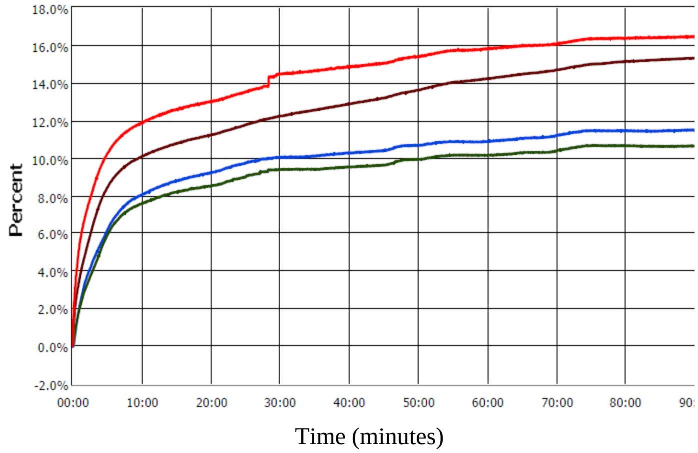
Shale Testing

X-ray diffraction analysis was performed on a Tunu shale sample to determine the swelling clay content of the material before designing the fluid. Table 1 shows the results of this analysis.

Next, linear swell testing was performed on shale samples to evaluate various shale inhibitors regarding their effectiveness in minimizing swelling of Tunu shale. Optimal shale inhibition was determined to result from combining 7% wt/vol potassium chloride (KCl) with two clay inhibitors at a concentration of 2% v/v each; Fig. 1 compares the fluid performances in this test. When the inhibitor concentration was increased from 2% v/v each to 3% v/v, no significant improvement was evident regarding the swelling of the shale samples.

Table 1 X-Ray Diffraction Results.

Content	Wt%
Quartz	26
Calcite	1
Sylvite	7
Plagioclase feldspar	1
Siderite	2
Illite/smectite mixed layer	20
Illite	20
Kaolin	23



	Maximum final swell percent
7% KCl	17.1%
7% KCl + 2% v/v inhibitor A + 2% v/v inhibitor B	11.2%
7% KCl + 3% v/v inhibitor A + 3% v/v inhibitor B	12.1%
Fresh Water + 2% v/v inhibitor A + 2% v/v inhibitor B	15.9%

Fig. 1 Linear swell test results.

Shale erosion tests were performed on a shale sample from an offset reservoir. These tests were performed over a 16-hr period at bottomhole static temperature to determine the capacity of the various fluid designs to minimize erosion of Tunu shale. This step is important in the fluid design process to gauge the potential effects of drilling and completion fluids on wellbore stability.

Fig. 2 shows a shale sample after a 16-hr hot roll erosion test with a 7% wt/vol KCl brine containing 2% v/v inhibitor A and 2% v/v inhibitor B. The shale erosion was calculated at 17.65%; this base fluid was deemed to be fit-for-purpose at this stage of the fluid design process.

Fig. 2 Shale erosion sample post-test.

Particle Size Analysis and Bridging Capability

Based on the estimated permeability of the Tunu reservoir, particle plugging tests were performed on 20 and 40 micron ceramic discs to determine whether or not the reservoir drilling fluid contained sufficient bridging material of the appropriate size. The test results demonstrated low spurt losses and overall fluid loss within customer's specification; Table 2 provides the results of this test.

Table 2 Particle Plugging Test Results.

Time Point (mins)	Fluid Formulation 1	
	Cumulative Fluid Loss (ml)	
	20 micron disc	40 micron disc
Spurt	0.3	1.8
1	1.2	3.1
7.5	2.8	5.1
15	4.2	8.0
30	6.0	11.0

The customer specified that the drilling fluid not contain particles with diameters of more than 70 microns. To ensure that this criterion was met, particle size distribution analyses were performed on locally sourced samples of sized calcium carbonate. A blend of two sizes of calcium carbonate, which provided the favorable fluid loss results discussed previously, was used to determine that the measured median, D50, of the drilling fluid was 23.04 microns.

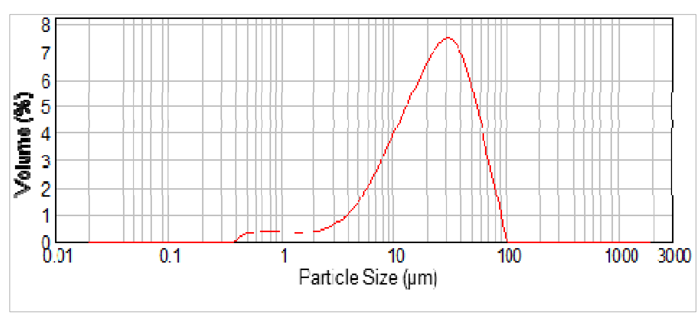


Fig. 3 Particle size analysis of the reservoir drilling fluid.

Although the preferred test method to confirm the fluid design would be return permeability tests, no core material was available from the Tunu reservoir to perform this test.

Completion Compatibility

The completion design for the Tunu well was standalone screens. A critical part of the fluid qualification process was to ensure that the fluid used to run the screens would not plug the openings and impair productivity.

In-house flow-through testing was performed on a sample of the drilling fluid against screen coupons. This test showed that the sized bridging particles contained within the drilling fluid did not pose a plugging risk. To minimize the plugging risk, it was decided to displace to a solids-free fluid to run in the screens, and retain the drilling fluid as a back-up solution.

Elastomer swelling tests were performed at a lab belonging to the elastomer supplier. These tests aimed to show that the drilling fluid components would not adversely affect the swelling time of the elastomer or turn the material brittle over time. Fig. 4 shows the swelling time profile of the elastomer when tested in the proposed reservoir drilling fluid. The results demonstrate that the ability of the packer to swell to its maximum OD (outer diameter) is not compromised by the components of the drilling fluid.

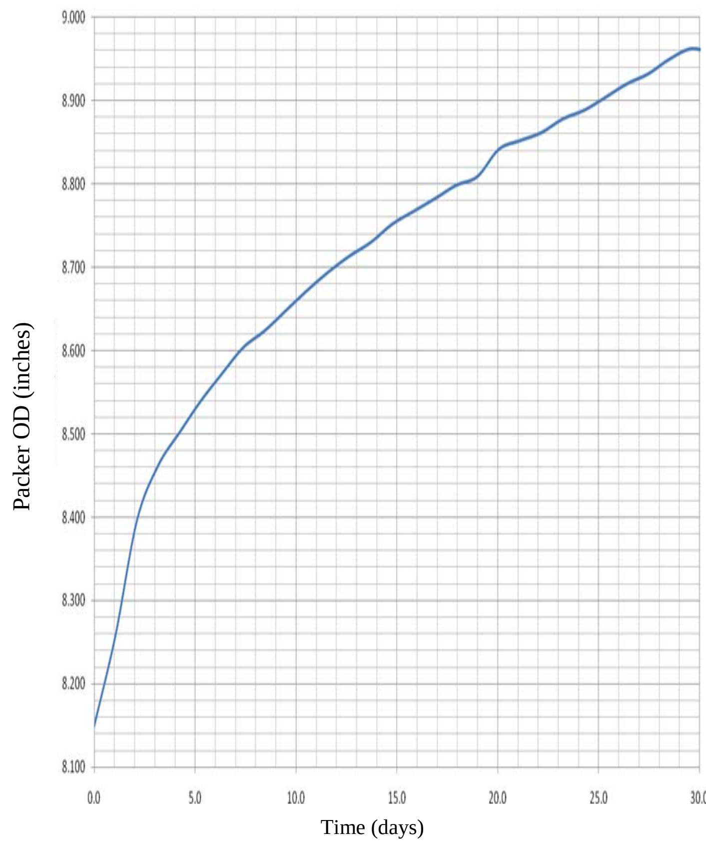


Fig. 4 Elastomer swell test profile.

Field Execution

The field execution process included drilling the reservoir, running the completion, and assessing the field results.

Drilling the Reservoir

The customized reservoir drilling fluid was selected for use in drilling one of the longest reservoir sections of the wells in the Tunu shallow gas field. The main objectives of the chosen trial well include the following:

- Replace synthetic-based mud with inhibitive water-based mud for environmental reasons.
- Enable a standalone screen completion to be run to bottom, eliminating the need for a gravel pack operation, and reducing rig time and its associated costs.

- Minimize formation damage during the drilling and completion processes.

To maintain the drilling fluid within target specifications while drilling the 8 ½-in. reservoir section, samples of active mud were taken after each 20 m drilled to test the particle size distribution and the production screen test flow-through test (PST), as well as the standard mud properties, such as particle plugging (PPT) and rheology.

At the customer's request, hi-vis pills were pumped every two stands to ensure that the hole was kept clean.

The 539 m reservoir section was drilled successfully with fluid properties maintained through the implementation of a rigorous "dump and dilute" strategy, and by carefully monitoring the PSD and PST in conjunction with stringent use of solids control equipment. Table 3 provides details about the final drilling fluid formulation used in drilling this well. Table 4 lists the fluid properties achieved during the drilling of the reservoir section.

Table 3 Reservoir Drilling Fluid Formulation.

Component	Concentration
1.07 sg KCl brine	0.86 bbl/bbl
Viscosifier	0.75 lb/bbl
Filtration control	7.0 lb/bbl
Alkalinity control	0.5 lb/bbl
Sized calcium carbonate	45 lb/bbl
Biocide	0.3 lb/bbl
Reservoir activator	2 % v/v
Shale stabilizer 1	2 % v/v
Shale stabilizer 2	2% v/v

Table 4 Drilling Fluid Properties during Field Execution.

	Programmed		Actual		Conformance
Name	Min	Max	Min	Max	
Density, sg	1.15	1.15	1.15	1.15	Yes
Plastic viscosity, cP		ALAP	17	18	Yes
Yield point, lbf/100 ft^2	18	25	21	25	
API filtrate, mL/30 min			3	3	Yes
Low gravity solids concentration (% by vol)	4	6	5.0	5.3	Yes
pH	9	9.5	9	9	Yes
Low shear rate viscosity, cP			6	6	Yes

The PSD monitoring ensured that appropriately sized bridging agents were added to the drilling fluid while drilling. This process minimized fluid loss to the formation.

The active content of clay stabilizers in the drilling fluid was monitored during the drilling phase; chemical replenishments were made in accordance with the fluid design requirements. This process provided a stable wellbore with the hole in excellent condition and no indications of shale swelling.

Running the Completion

To minimize the risk of plugging the sand screens, the displacement design required displacing the drilling fluid to a solids-free drilling fluid, as previously described. Before pumping the solids-free fluid, the fluid was tested at surface to ensure it passed the PST test and would not plug the sand screens after they were installed.

After the 8 ½-in. section was drilled to section TD, a hi-vis pill was pumped and the open hole was displaced to a solids-free water-based mud. The pipe was pulled back inside the casing with no rotation or pumping, which indicated that the wellbore was in good condition.

The casing was displaced to filtered KCl brine by means of a series of casing clean-up pills. The 5 ½-in. sand screens were then made up and successfully run in hole to the target setting depth of 1411 m.

Field Results

Successfully running standalone screens in this well reduced the customer costs by eliminating approximately five days of rig time by avoiding a gravel pack operation. In addition, the costs that were associated with cuttings handling and disposal when using synthetic-based muds in previous Tunu field wells were eliminated. After a 10-month evaluation period of this well, the operator has achieved production rates of up to seven times greater than the initial target.

Conclusions

Thorough laboratory testing is vital in the engineering design of reservoir drilling fluids, particularly for establishing optimal performance from water-based drilling fluids aimed at replacing synthetic-based fluids.

Field monitoring of particle size distribution and flow-through characteristics of the reservoir drilling fluid and solids-free fluid is critical for successful reservoir drilling and open hole completion operations.

Optimal fluid displacement plans regarding to completion type and rig limitations played a key part in this field example, especially with regards to flow rates when displacing the open hole to ensure minimal disruption to the filtercake.

Acknowledgments

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