Case History
Reservoir Fluids

Reservoir Drill-In Fluid Minimizes Fluid Invasion and Mitigates Differential Stuck Pipe
Location: Middle East

OPERATOR’S CHALLENGE – The operator faced production challenges on freshly drilled sandstone reservoirs due to plugged sand screens on production, which put the well on workover operations in less than a year. Investigations showed that the water based drill-in fluids previously used in the well allowed fluids and fines to invade the formation and plug the sand screen during production.

In the next two workover wells, the operator’s objectives were:
• Drill vertical side tracks of ±300 ft and ±400 ft in the 5-7/8” hole section for the two wells
• Run 4-1/2” conventional sand screens to the bottom without any issue

Offset well analysis showed incidences of tight spot, partial losses and metal shaving in this hole section.

HALLIBURTON’S SOLUTION – The Baroid technical team reviewed offset wells and production challenges with the operator to meet the following objectives: minimize fluids invasion; minimize formation damage; no differentially stuck pipe; no down hole losses; and no tight spots.

Baroid proposed an integrated approach of:
• Customized BARADRIL-N® reservoir drilling fluid for 280° F
• Drilling Fluids Graphics (DFG™) software to monitor hole cleaning and Equivalent Circulating Density (ECD)
• Particle Plugging Test (PPT) and Particle Size Distribution (PSD) to monitor fluid and solids invasion

The sandstone reservoirs were drilled for the two wells with the customized BARADRIL-N reservoir drilling fluid. In addition, N-DRIL™ HT PLUS non-damaging fluid loss polymer provided excellent fluid loss control at 280° F with a thin filter cake, and sized BARACARB® bridging agent provided efficient bridging, thus minimizing fluid and solids invasion to the formation. The fluid was constantly monitored during drilling with PPT and PSD tests.

Particle size distribution tests showed that sized BARACARB® bridging agent provided efficient bridging, thus minimizing fluid and solids invasion to the formation.
Constant monitoring with DFG software ensured an average Rate of Penetration (ROP) of 25 ft/hr and low ECD, thus minimizing induced losses and tight spots. The reservoir section was drilled with an overbalance greater than 1430 psi with no differentially stuck pipe incidents.

The integrated approach provided a stable bore hole with wire line logs and 4-1/2” conventional sand screens being run with no issues.

Initial flow back production testing took 8 hours showing an improvement of 80% compared with 48 hours required in the offset wells. The BS&W (Basic sediment and Water) from day 1 of production was 9% as compared to the 25% observed in the offset wells. Excellent improvement in the gas production rate was observed as compared to the offset wells.

**ECONOMIC VALUE CREATED** – The earliest initial flow back saved 40 hours operation time, thus the saving the operator 58,000 USD. In addition, improved gas production rate and the low BS&W made the customer classify the two wells as high potential thereby maximizing the wellbore value.