Greenland joins arctic exploration fray

Gjøa hub marks new trend

The optical effect on reservoir management

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A high-profile North Sea discovery called for innovative engineering to enable representative formation fluid sample collection and critical measurements of H₂S concentration.

The wells operated by BG Group represented tough challenges on several fronts. The presence of a small concentration of sour gas was suspected, but its level was unknown. This missing piece of critical information could affect the well completion and production scenarios and impose a significant expense should the concentrations be high enough to warrant the use of costly alloys in completion/production hardware, not to mention the added costs associated with operational safety and waste disposal. Alternatives were limited.

The operator could find out the information by implementing an extended well test, but even then results were not guaranteed. Measuring accurately low concentrations of H₂S can be problematic, because the test equipment reacts with the sour gas and affects the quality of the measurement. The risk of implementing a well completion plan and building a production facility based on unreliable data was unacceptable.

The alternate choice was to take downhole formation fluid samples using a wireline formation tester and perform a detailed laboratory analysis of the samples in one of the wells and also conduct extended well test in the sidetrack of the other well. However, the danger of H₂S scavenging within the metallic components of the tool and sampling bottles is still present with wireline formation fluid sampling. Could BG Group depend on the answers for its critical decision-making?

Evaluation results

BG Group petrophysicists had been collaborating with Schlumberger engineers on the well evaluation program and concluded that the measurement of H₂S concentration could be obtained in conjunction with the logging program. A thorough wireline logging program was designed. It consisted of six runs. First, a basic suite of petrophysical evaluation logs were run, followed by the wellbore imaging logs. Next came nuclear magnetic resonance logs combined with PressureXpress reservoir pressure while logging service logs, which also provided a quick formation fluid mobility profiling. The fourth run was the critical formation fluid sampling and downhole fluid analysis log. The final two runs included vertical seismic profiling for depth tie-in and modeling and the mechanical sidewall coring tool.

Well conditions were challenging. The first well was drilled with 15.7 lb/gal (1.88 g/cm³) oil-based mud with high solids content. This resulted in over 725 psi (5000 kPa) overbalance, which was expected to cause significant mud filtrate invasion in the pay zones. Fine grain size was expected at the test depths that could contribute to plugging of the test tools. Lastly, formation fluid mobilities in this well varied between 5 mD/cP and 75 mD/cP.

The combination of formation and fluid conditions at the test depths created problems for successful sampling. First, invasion of mud filtrate contaminated the near-wellbore region, leading to exceptionally long pumping times waiting for the sample fluid to clean up. Trying to speed up the flow rate by increasing drawdown intensified the potential of tool plugging from the dislodgement of fine grain solids from the sandface.

Schlumberger had a solution for the clean-up problem. By using its Quicksilver Probe focused extraction of reservoir fluid, the time required to obtain an uncontaminated sample could be significantly reduced. This device surrounds the sampling probe with a guard probe that funnels off the contaminating mud filtrate and pumps it into the mud column.

To control drawdown and minimize pumping time, the focused extraction of reservoir fluid technique was coupled with an extra-high pressure displacement unit on the fluid collection flowline and a high pressure displacement unit.
on the guard flowline. These allowed pumping fluid with slowest rates.

The combined minimum flow rate when running both pumps was 0.32 in.²/sec (5.3 cm²/sec). With the ability to quickly acquire uncontaminated formation fluid, station times could be kept well-within the guidelines imposed by the operator’s drilling regulation, which is influenced by stricter high-pressure/high-temperature (HP/HT) well environment. An LFA live fluid analyzer and a CFA composition analyzer were run with MDT modular formation dynamics tester for real-time contamination estimation and formation fluid compositional analysis. These data were transmitted to the operator’s offshore office in real time for efficient sampling operation decision making.

Despite the apparent solution to the drawdown and plugging issue, concern remained on the issue of H₂S scavenging. Even though it is possible to minimize tool damage due to H₂S embrittlement or stress cracking of metal components, any scavenging of the gas by absorption would reduce the ability to measure accurately its volume and concentration. Absorption can be limited through the use of special alloys such as Inconel, Titanium, or Monel. It can also be reduced through the use of special coatings of internal metal surfaces. These measures would be used, but in addition, an elegant solution was used — reduce the flow path of the contaminated fluid.

Taking advantage of the formation tester tool’s modularity, and using a reverse low-shock technique, the tool string was configured with the sample bottles carrier located only 7.6 ft (2.31 m) above the probe instead of the conventional 35 ft (10.7 m) above the probe. Where the backside of the sample bottle pistons were traditionally open to the mud column, under the revised plumbing arrangement they were backed up by a water cushion allowing the chamber to fill and displacing the water cushion (blue).

However, using the Quicksilver Probe would require between one hour and 1.4 hours to reach the 10% contamination level. The combination of reduced sampling time and the reverse low shock technique ensured scavenging would also be minimized and accurate measurements could be achieved.

Four tests were taken in each of the two wells. Each well had three oil samples and one water sample taken. Continuously monitored in real time by the integral LFA and CFA modules located in the flowstream, fluid contamination levels were estimated throughout the tests.

As soon as the filtrate contamination level decreased to 10% or less, a sample was taken. Average cleanup volume was 13.2 gal (50 l). Subsequent laboratory analysis measured contamination at 1%, 5%, and 6% by weight percent of reservoir fluid in the oil samples taken in the first well. Samples with contamination levels of 0-2% were obtained in the second well from which accurate H₂S levels could be obtained. These data were critical factors in subsequent completion and production decisions.

During formation testing and sampling, the field engineer and remote witnesses have all the key elements in view as sampling progresses, including formation pressure, gas/oil ratio (GOR), and optical densities. Nuclear magnetic resonance (NMR) permeability, resistivity, and density/neutron logs are also available. The oil composition fractions from the CFA are displayed on a bar graph for each sampling station as well as drawdown mobility. It is worth noting that fluid composition was changing with depth. While the vertical distance between the two tests shown is only 8.2 ft (2.5 m), the GOR and C2-C5 are both increasing with decreasing depth.

The Quicksilver Probe allowed samples to clean-up in 1/10th of the time. The reconfiguration of the test tool minimized H₂S scavenging so accurate H₂S concentrations could be quantified.