Brazil cases demonstrate LWD advancements in deepwater pressure measurement service

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DEVELOPMENT OF A formation pressure measurement system while drilling has long been a wish and a challenge for the oil industry. With substantial progress in tool and procedures design, the pulse of LWD advancements in the area of pressure measurement in deepwater is becoming clearer as a result of field applications in Brazil's Campos and Espirito Santo basins. Over a period of one year, a new-generation LWD service was fielded 11 times to test operating functionality and prove its capability of efficiently acquiring reliable static formation pressure measurements.

The availability of a flexible and efficient LWD technology is creating options for reservoir evaluation and development in deepwater, including Brazil's mature fields where a closer well spacing is being proposed. In field applications to achieve these goals, the StethoScope formation pressure while drilling tool was used to diagnose compartmentalized sands, identify fluid in-situ by means of pressure gradient, analyze fault effects on pressure transmission, and discover interference between injector and producer wells in Brazil's deepwater environment.

BASIC CHALLENGES

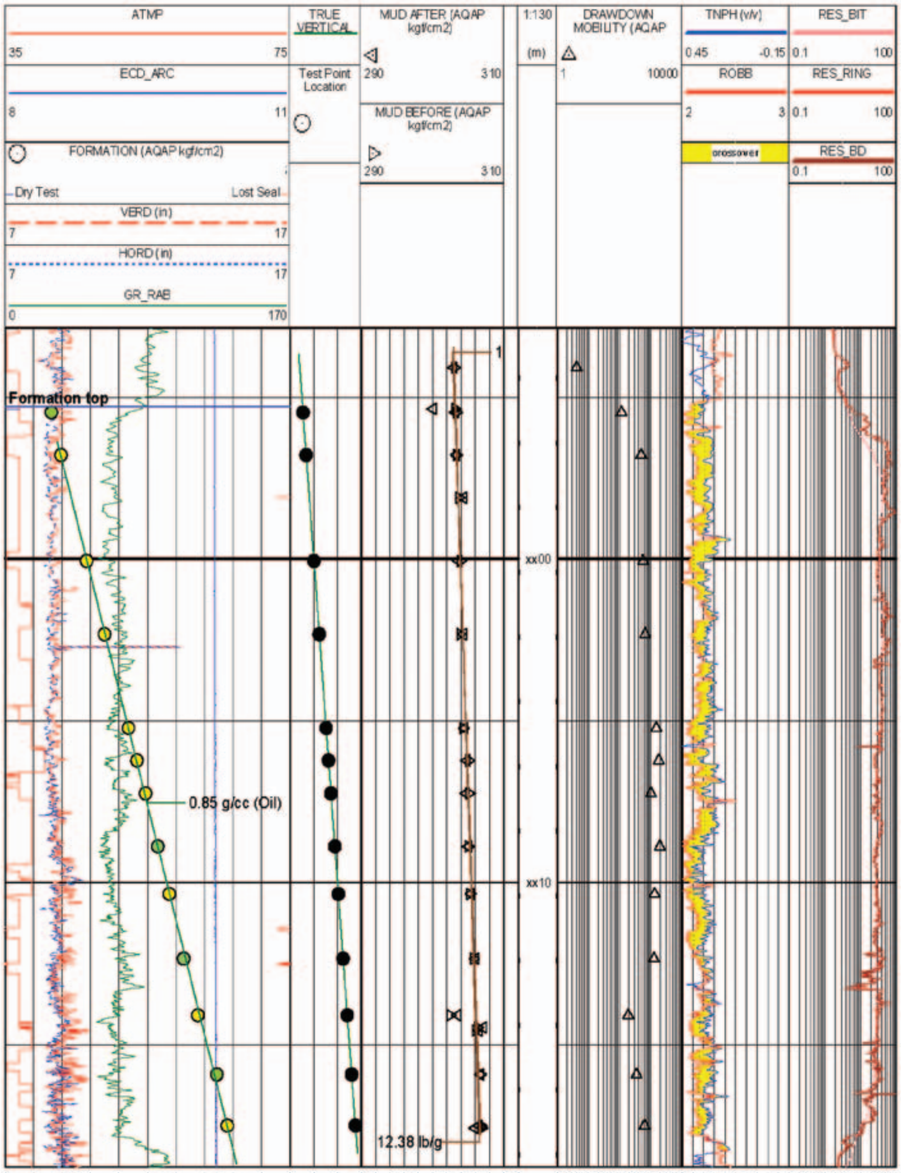
Whenever reservoir engineers and geologists need to acquire logging data for formation and fluids evaluation or monitoring, several factors need to be weighed to justify the cost and potential risk of data acquisition. Deepwater offshore field development using deviated and horizontal wells strategies heightens exposure to risk. On a subsea completion, it is of utmost importance to obtain the maximum amount of data during the drilling phase as a second opportunity is often not possible or practical. With the current drilling trend focused on highly deviated wells (more than 60°), the physical limit of gravity conveyance clearly has been exceeded.

Challenges to development of a suitable LWD pressure measurement include lack of electrical cabling connecting surface equipment to the downhole tool. Also, we cannot achieve the large transmission rates available on standard logging cables. Instead, all communication to and from the tool must occur using a relatively slow mud pulse telemetry (6-12 b/s). As a direct consequence of the MWD telemetry bottleneck, the LWD tool needs to be far more "intelligent" than its wireline equivalent and must be able to process and distill information downhole, sending only what the operator requires to know in real time. Depending on the objectives of the job, the amount of information transmitted must be allowed to vary. In addition, an LWD tool has to survive drilling conditions and may be used under atypical circumstances, such as before mud cake has fully formed and dynamic filtration has stopped, or simply while circulating.

TESTING THE FORMATION

The formation pressure while drilling (FPWD) tool has a single-probe packer system located within a uniquely designed semi-spiraled stabilizer blade. A drillable setting piston positioned on the opposite blade is employed to push the stabilizer containing the probe against the formation face, enabling tests to be taken regardless of the tool or

Figure 1: Pressure depth plot



borehole orientation. Once set, the rubber packer creates a sealed zone with the mud cake. It has an outer diameter of 2.25 in. (for StethoScope 675) and an inner diameter of 0.56 in., where the fluid is allowed to enter the probe. The probe has a stroke of 0.75 in., ensuring that a seal is created in rugose holes. The stabilizer design maximizes the flow area in the cross section of the probe, diverts mud flow away from the probe-to-formation interface, and minimizes the mud velocity in the vicinity of the probe, thereby helping to reduce filter-cake erosion and filtrate leakage into the formation while testing.

The tool has 2 pressure gauges on the flowline, an ACQG, a Schlumberger advanced crystal quartz gauge, and a strain gauge (for data assurance), and a strain gauge on the annulus side, giving annulus pressures while taking the pretest. Pretest volume is adjustable up to 25 cc, and the drawdown rate can be varied from 0.1 cc/sec to 2.0 cc/sec. The automated pretest sequence can be selected from a set of 4 pretest options or can be customized using client-defined settings. Test time in nearly every case is less than that required to make a drillpipe connection.

The tool is capable of analyzing both virgin and developed reservoirs. In virgin reservoirs, pressure profiles can be combined with other LWD logs to develop a static model of the reservoir. Pressure profiles from wells in a developed reservoir aid in understanding of fluid movement within the reservoir. These pressure profiles defining gradients and contact points, combined with production history and the static reservoir model, are used to model the dynamic reservoir pressure — a crucial element for optimizing recovery as this enables an increased understanding of a field's production systems and better completions.

Two modes of operation were employed during tests in Brazil: pumps off and on. The benefits of pump-off mode are minimizing dynamic interferences and mitigating supercharging effects, an option useful for formations with low mobilities. In test cases where the formation mobilities were verified to be high, it was preferred to keep pumps on to monitor formation pressures in real time.

FIELD EXPERIENCES

Over a time span of less than one year, 11 jobs were performed using a 6 ¾-in. tool in 8 ½-in. and 9 ½-in. holes and an 8 ¼-in. tool in 12 ¼-in. boreholes.

In the first 2 jobs, a StethoScope 675 tool was used to record pressure data after the wells had already been drilled to total depth. Resulting data showed that a consistent gradient could be drawn across all points acquired, proving sand continuity and the absence of an injection or depletion effect. The local formation pressure gradient was consistent with the expected oil density; consistency of this gradient was comparable to the top MDT jobs performed.

A stabilized spherical or radial flow could be identified on the derivative analysis. A total of 20 tests were attempted in less than 7 hrs, achieving 14 valid stations.

It was confirmed that maximum accuracy in data could be obtained when all pressure stations are acquired under similar conditions at the end of drilling, when depth errors are minimized and extra pipe movement avoided.

Gradient ranges

From (kgf/cm2 .m)	To (kgf/cm2 .m)	Fluid Type Is:	Color
0.000	0.025	Gas	
0.025	0.050	Condensate	
0.050	0.093	Oil	
0.093	0.098	Heavy Oil	
0.098	0.117	Water	
0.117	0.153	Mud	
0.153	and higher	Invalid	

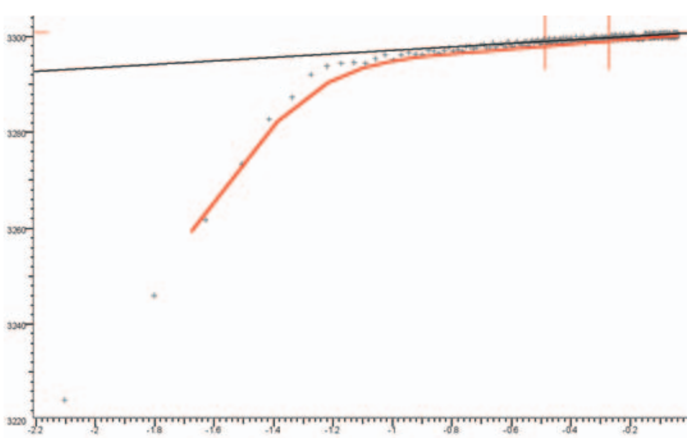
Pressure gradients

Gradient kgf/cm2.m	Density g/cc		Gradient Caption	Top m	Base or Contact m	R^2	STD Kgf/cm2	Comment
Formation Pressure Lines								
0.084	0.84		0.84 g/cc (Oil)	2494.69	2518.33	0.9991	0.0200	Todos os pontos
0.085	0.85		0.85 g/cc (Oil)	2496.25	2518.15	0.9996	0.0100	Todos os pontos menos o mais raso

Mud Column Gradients

Gradient kgf/cm2.m	Density lb/g		Gradient Caption	Top m	Base or Contact m	R^2	STD Kgf/cm2	Comment
Mud Before Lines								
0.161	13.44		13.44 lb/g	2493.61	2517.77	0.9733	0.2300	Valores de gradiente durante a circulacao
Mud After Lines								
0.148	12.38		12.38 lb/g	2493.47	2518.02	0.9235	0.3500	Valores de gradiente durante a circulacao

Log-Log plot: dp and dp' (psi) vs dt (sec)



Semi-log plot: p (psia) vs Superposition time

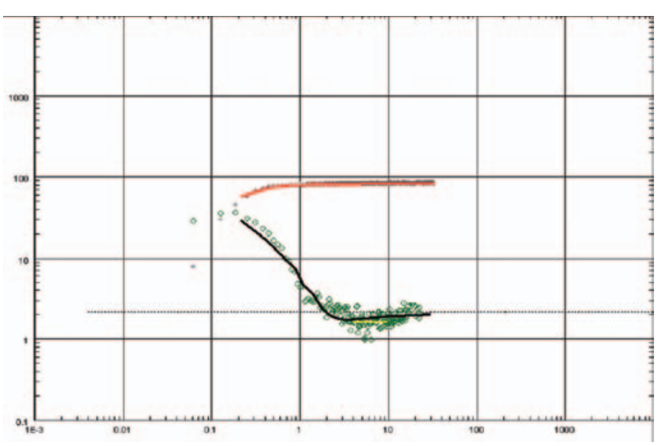


Figure 1 (shown above and on facing page): During the first offshore test in Brazil, the StethoScope tool was used to record pressure data after the well had been drilled to total depth. The consistency of the computed gradients proves the quality of the data to be comparable to the best MDT jobs performed.

Following lessons learned on the second job with regard to beneficial collar sizes and effects of a non-homogeneous depletion, a first attempt was made to use the tool to actually drill a well in Espirito Santo basin. For this job (Job No. 3), which was actively geo-positioned, the reservoir engineers' interest was to understand the effect of the faults likely to be crossed. The data acquired while drilling demonstrated that the pressure regime was the same before and after crossing a fault. No gradient was computed as the difference in TVD among all the stations acquired in the main sand was less than 1 m. The 1,190-m drain hole was drilled in 2 runs. Formation pressure data was also used to optimize mud weight.

A fourth job involved the first performance of a larger version of the FPWD tool having a nominal collar size of 8 ¼ in. and 12-in. stabilizer in a 12 ¼-in. hole. The system was used to drill 1,277 m for a total of 3 runs, acquiring 17 good tests and 5 dry tests out of 34 attempts.

Tests from the subsequent job (No. 5) were acquired in a 12 ¼-in. pilot well. The original objective was to drill an injector well in a zone with an expected depletion, where there was already a producer well. Two different sand bodies were found. The upper zone did not have an ideal vertical thickness to drill a horizontal well, and the pressures measured in the lower zone were 20 kg/cm^2 higher than in the upper zone, indicating that these 2 zones were not in communication as originally thought. The lower zone, still at virgin pressure, was proved not to be in communication with the producer well. As a result of the data obtained from the real-time LWD formation test, the extremely time-critical plan to drill the well in the lower zone was abandoned, and an alternative target was selected. Not only the cost of the horizontal well was saved, but a significant increase in the local reservoir understanding was achieved.

Another job (No. 6) was the first to be performed in a carbonate reservoir. Due to extremely low mobilities, the slowest possible pretest sequences were used. Only 2 stations resulted in measured mobilities above 1 mD/cP, and most of the stations were affected by supercharging. A comparison run with a wireline tester provided a similar mobility profile and demonstrated that the results were predominately formation- and invasion-dependent. It was found that the quality of results could be improved under similar conditions by extending the time between drilling and pressure data acquisition.

The remaining jobs performed offshore Brazil confirmed the tool's reliability as a source for pressure measurement during the early life of a well. One job performed in a 12 ¼-in. pilot hole demonstrated sands compartmentalization and identified a change in oil properties with depth. A comparison was made with data obtained with wireline and real-time fluid identification performed with an MDT-DFA combination; the fluid property identification matched what had been previously diagnosed using the in-situ pressure gradient.

The promising results obtained during these tests in Brazil's deepwater basins have offered proof of the progress that has been made in LWD formation evaluation. The impact of these advances is still being analyzed as additional applications are introduced and an even more systematic use of the tool is envisioned.