The Art of Achieving Petrophysical Consistency While Missing Key Logs: Example of a Gas Discovered Resource Opportunity Offshore Niger Delta

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ABSTRACT

The Niger Delta has a significant number of wells drilled in the 1960s and 70s tainted by log quality problems – but even in more recent wells with modern logs, operational issues or mud effects can compromise key logs… the challenge is then to produce an interpretation that remains geologically and petrophysically consistent. This paper highlights practices that can be used in reconciling high- and low-quality logs, even in the presence of low-resistivity, low-contrast pay.

In this case study of a gas discovered resource opportunity, only two wells are available to characterize the reservoir properties of interest; one drilled in 1998 with density log issues and another drilled in 2007 with overall good logs including NMR. The paper illustrates how a complete and robust petrophysical assessment can be conducted on both wells in the absence of the critical density log in the critical intervals of the first well, using the neutron and sonic logs as a substitute. Different mud types were used which affected the sonic log differently, so the porosity-depth trends were used to guide the porosity modeling.

High-water-saturation transgressive intervals were also delicate to interpret, but NMR logs helped clarify reservoir quality in these intervals. The neutron-sonic approach combined with a dual-water saturation estimation was able to resolve low-resistivity pay, which significantly increased the pay thickness of some sands compared to a more conventional petrophysical assessment. This combined approach prevented potential underestimation of pay thickness and ultimately gas-in-place and reserves, which is a key consideration for acceleration of field development to meet the growing local gas supply demand in Nigeria.

The resulting petrophysical characterization was robust enough to be fully endorsed by all partner companies on the project.

Keywords: Compaction trends, Oil Based Mud, Water Based Mud, Cross Plotting, NMR log,

INTRODUCTION

The Niger Delta is a world-class basin that has been explored and produced for oil and gas over several decades. With this legacy, however, also comes the burden of older logs that might have been miscalibrated, extremely prone to hole rugosity, affected by deep mud filtrate invasion (usually in the presence of water-based mud or WBM) or even whole mud invasion, or simply gone missing. Oil-based muds (OBM) substantially improved hole stability and overall log data quality, but were not used until the late 1990s – so even though the logging tools had substantially improved by that time, data quality remained an issue well into the 21st century.

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When it comes to computing field studies mixing data vintages, there is often a need to enforce consistency that might otherwise be lacking from the data as found.

This paper discusses the application of some log analysis techniques we found useful in the Niger delta, specifically taking the example of a gas discovered resource opportunity (DRO) that was recently re-analyzed for the purpose of field development planning. Two wells are the focus of this study that penetrate the same dipping structure and stacked sands, about 2500 m apart. The sands are grouped into two families split by age – A (shallower sands) and B (deeper sands).

Well 1 was drilled in 1998 as an exploratory well near the crest of the structure. It was drilled with WBM in the A sands and encountered several gas-water contacts (GWC); it was continued with OBM across the B sands and encountered full gas saturation. Well 2 was drilled in 2007 as an appraisal well down-structure to test reservoir extent and log fluid contacts not encountered by Well 1 in the deeper zones, wholly with OBM. The A sands it encountered are wet, but the B sands bear gas and exhibit several GWCs. Logs run in both wells include quad-combo (Gamma Ray, Resistivity, Neutron-Density, Sonic), plus NMR in Well 2. The mud log from Well 2 is also available – but not that of Well 1. Formation pressures, fluid samples and DST were also acquired in both wells to confirm fluids; this is extremely valuable information, but not in scope of this paper's discussion.

We first summarize essential steps in the integration of log data to produce consistent compaction trends for Well 2. Then we discuss how the sonic log was used to mitigate the absence of a density log in Well 1, and its caveats. Next, we focus on the resolution of low-resistivity pay in the transgressive intervals of some of the key target reservoirs of the DRO. We conclude this paper with a discussion of pay definitions.

Compaction trends

Let's first discuss some caveats and best practices of log analysis in gas reservoirs after log data QC and a first-pass quantitative analysis is run on Well 2. The petrophysical workflow employed in this project uses a simple 3 points (sand-shale-fluid) approach, whereby Vshale (shale volume fraction), porosity and water saturation are defined simultaneously from the neutron, density and resistivity logs using a dual-water approach. As mentioned further, the "shale" present in the shaly sands in the transgressive intervals and the "shale" separating the sand units have distinct properties. There is a marked transition between the two "shales" around 50% Vshale. An alternative to this petrophysical model would have been to use a multimineral solver that explicitly models the two shale types.

To establish reliable compaction trends for clean sand porosity, one must ensure gas effects have been adequately incorporated – i.e., that gas effects on the neutron and density logs are consistent with near-wellbore gas saturation. If an NMR log is available, one expects the free-fluid pore volume to be underestimated in those gas intervals, consistent with the density log. In case of WBM drilling, one must keep in mind that many wells from the region were drilled overbalanced and WBM filtrate many times flushed gas away from the near wellbore, hence no gas effects on nuclear logs. A deviation from the expected compaction trend could have geological meaning, but also could wholly be due to log quality issues. For instance, whole mud invasion would reduce the computed porosity in permeable intervals while hole rugosity would increase it. Given the high porosities encountered in the Niger Delta, an incorrect gas correction would create a porosity swing as high as 5 to 10 porosity units if neglected.

As for shale porosity, it highly depends on the selection of dry shale density. Short of core measurements in the shales, an NMR log (even just a down-log that captures bound water signal) provides a good calibration of shale porosity if there is no hole rugosity.

All these steps were implemented with the full log suite of Well 2. Figure 1 illustrates the resulting compaction trends. A major assumption supported by seismic interpretation for this DRO, is that there is no faulting or folding in the immediate region around Wells 1 and 2, and therefore the derived compaction trends are expected to hold for both wells.

Sonic logs – a double-edged sword

Borehole-compensated sonic logs are present in both wells

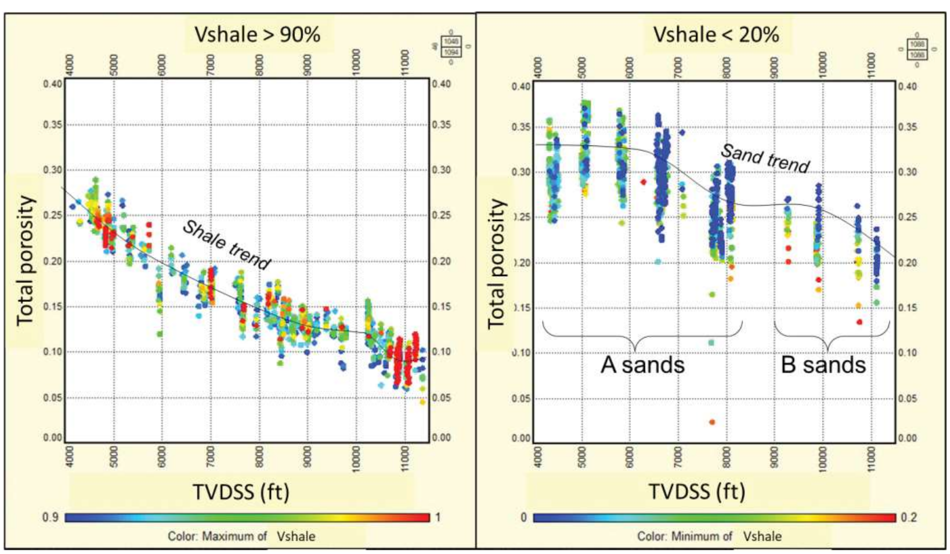

Figure 1: Compaction trends defined in Well 2 from triple-combo log analysis. Left: shale trend; right: sand trend. Both as a function of true vertical depth subsurface (TVDSS).

and seem of decent quality with no cycle skips. While it is now conventional practice to predict missing logs from other existing logs using neural net, clustering, or other machine learning software packages, one must be sure to first understand the sensitivity of those logs.

Let's start with the estimation of Vshale, the shale fractional bulk volume. As illustrated in Fig. 2, the logs most sensitive to the transition from shale to sand unit (transgressive interval) are the neutron porosity and the resisitivity. The GR and density logs only react to the cleaner sand intervals, while the sonic DT has minimal dynamic tendency. Our petrophysical model therefore requires the neutron log for a Vshale computation. After careful tuning, a neutron-sonic Vshale calculation produced results very similar to the neutron-density calculation adopted for the field, per the employed sand-shale-fluid interpretation workflow.

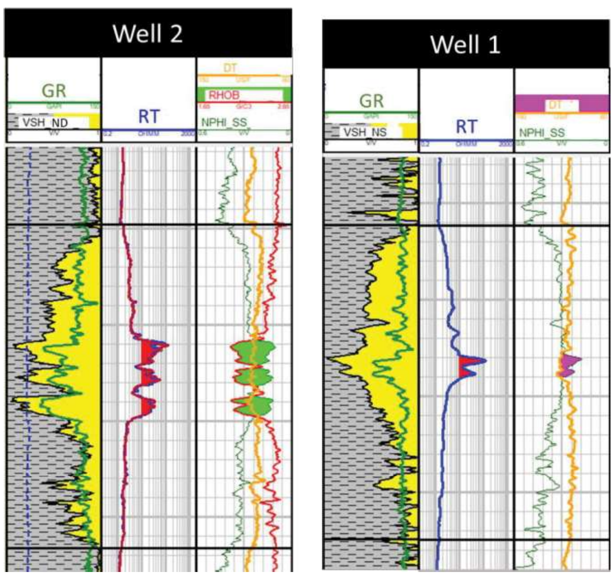

Figure 2: Log layout of Vshale computed across the same B sand for both wells, using different logs. Left: at Well 2, using neutron and density logs; green highlights neutron-density gas crossover. Right: at Well 1, using neutron and sonic logs; magenta highlights neutron-sonic gas crossover. Black horizontal lines mark the top and base of the sand unit. Each vertical division equals 5 ft.

Next, let's focus on porosity estimation. In Well 1 a deceptively simple correlation can be derived in the shallow A sands drilled with WBM between porosity computed from triple combo logs and acoustic transit time DT in gas sands, regardless of Vshale (Fig. 3). Let's call this Model 1. Once applied to the B sands interval which have no density but sonic log, Fig. 4 shows Model 1 produces too low porosity values of about 10 porosity units in those B sands, due to the difference in mud system. It is therefore essential to refer to context – here, the expected sand compaction trend – to assess the quality of log prediction(s) when a parameter as important as mud type varies.

If mud type is the main factor to better predict porosity from the DT log, we can turn to Well 2 that was solely drilled with OMB, albeit nine years later. The behavior of the sonic log in that well is extremely different from what is observed in Well 1 with WBM. This time, there is a strong dependency on Vshale but not on fluid (Fig. 5). One can select a clean sand trend (Vshale < 20%) and a shaly sand trend (Vshale > 50%) that fit both pay sands and wet sands… and then interpolate between the two trends as a function of Vshale. As shown in Fig. 6, the result fits very well the porosity otherwise computed from triple combo logs in Well 2. The result was deemed good enough to require no further machine learning.

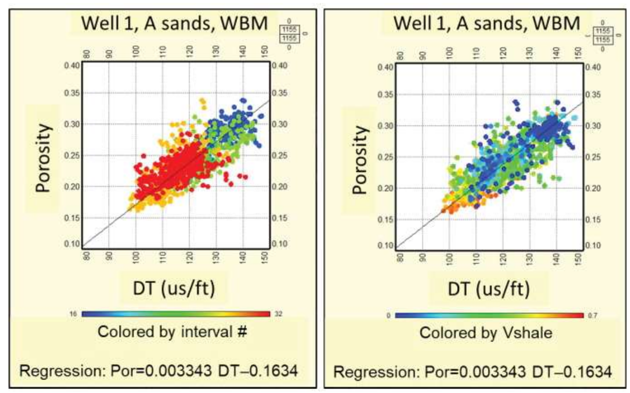

Figure 3: POROSITY MODEL 1: A simple regression correlates DT and porosity in the A sands of Well 1. Left: colored by sand #. Right: colored by Vshale value.

The key test is then to again compare the predicted porosity against the expected compaction trend. We apply Model 2 developed in Well 2 drilled with OBM to the B sands of Well 1, also drilled with OBM. The resulting predicted porosity fits the expected compaction remarkably well, as shown by Fig. 7. We also tried other industry standard sonic porosity models (e.g., Bateman-Konen neutron-sonic porosity also using Vshale weighting) but could not quite achieve results that follow the compaction trends so consistently.

Saturations and low-resistivity pay

The second thrust of this paper is to discuss the quantification of low-resistivity gas saturations in shalier sand intervals, and reduce the risk of modeling error. It was mentioned earlier that a dual-water saturation model seems to fit the Niger Delta very well. Not shown here, we

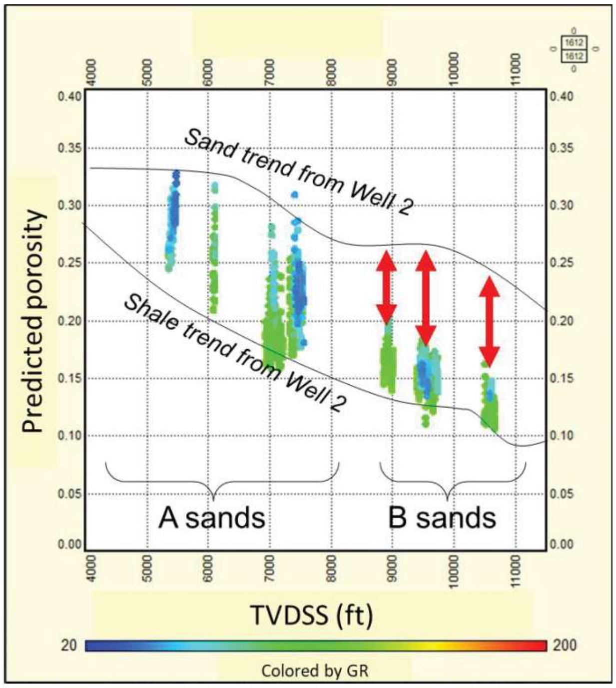

Figure 4: Porosity predicted for Well 1 from sonic log using MODEL 1, overlaid on the compaction trends established in Well 2. While the porosity prediction fit the expected range in the A sands, there is a discrepancy in the B sands indicated by the red arrows.

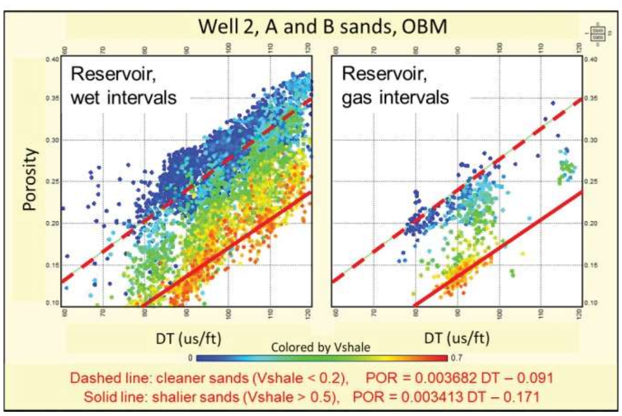

Figure 5: POROSITY MODEL 2. Linear regressions define porosity as a function of DT in Well 2 for clean sands (dashed line) and shaly sands (solid line). The same regressions hold in wet intervals (left panel) and gas-filled intervals (right panel).

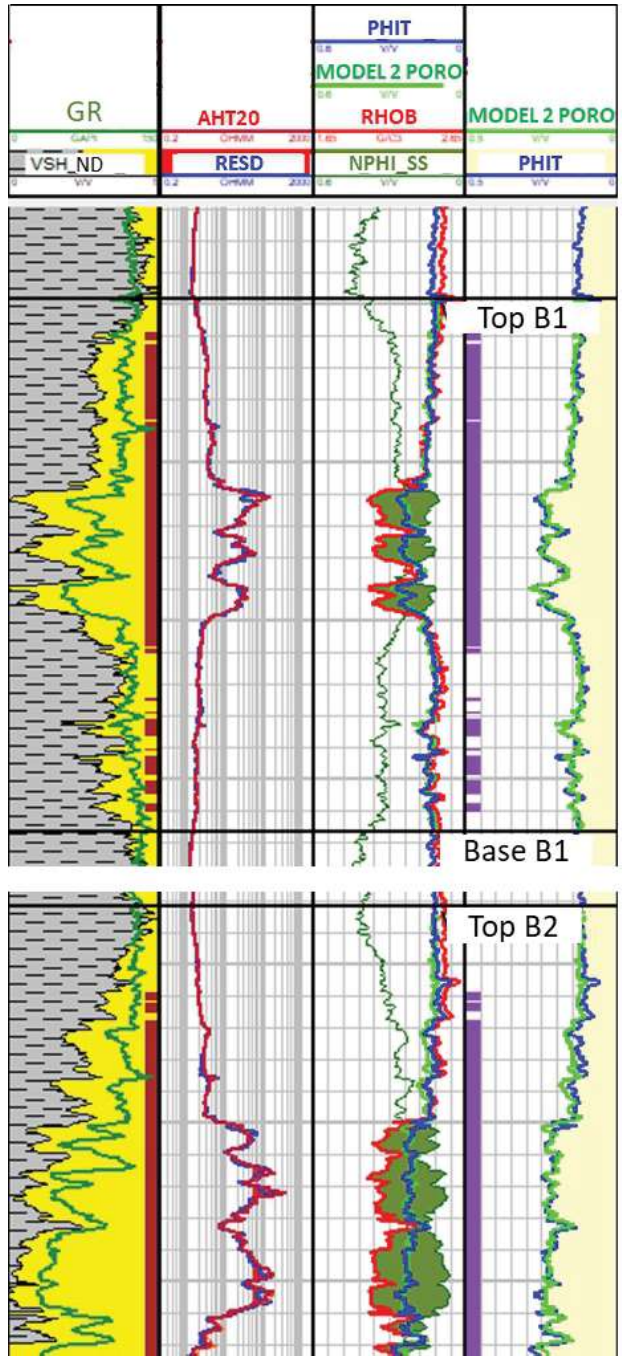

Figure 6: Layout comparing triple-combo based porosity (blue) and porosity predicted from sonic log (green) using Model 2 for two sands of Well 2.

encountered laminated sand/shale thin-bedded pay in other fields of the Delta and in deep water, and even though the dual water approach is designed to model electrical conductivity in the presence of dispersed shale it seems to remain appropriate for laminar shale too. Indeed, in those examples there was no material difference between the saturations computed from dual-water resistivity model, from thin-bed analysis, from Thomas-Steiber analysis or from NMR analysis – henceforth, our consistent use of the dual water model as long as its sand and shale end points are accurately selected.

First let us define the shale clay-bound water content. This is a key parameter of the dual-water model, since it bears

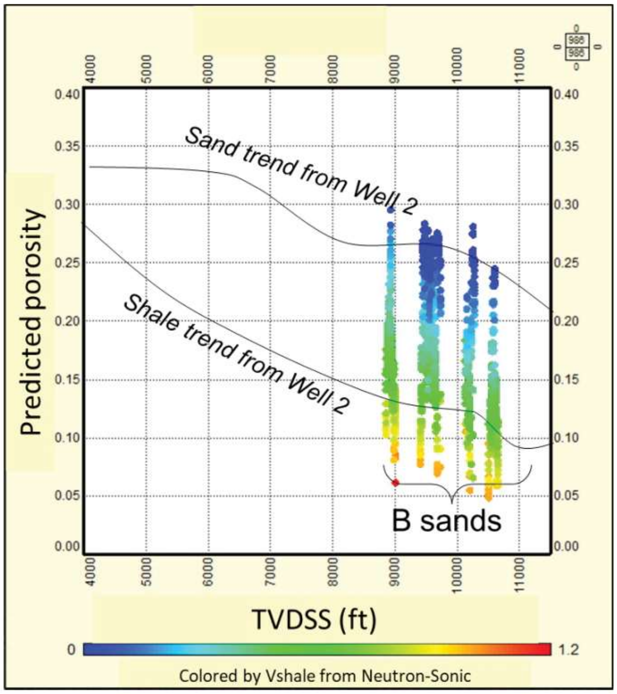

Figure 7: Porosity predicted for the B sands of well 1 from sonic log using MODEL 2, overlaid on the compaction trends established in Well 2.

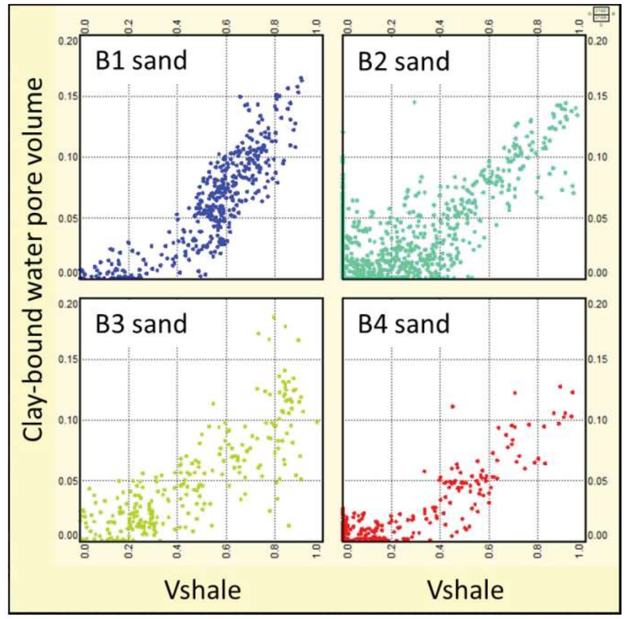

Figure 8: Crossplots of clay-bound water pore volume (from NMR log) vs. shaliness (from neutron-density logs) in B sands of Well 2.

the extra conductivity that will allow hydrocarbon in low-resistivity shaly sands. Figure 8 shows the volume fraction associated with clay-bound water across the four B sands

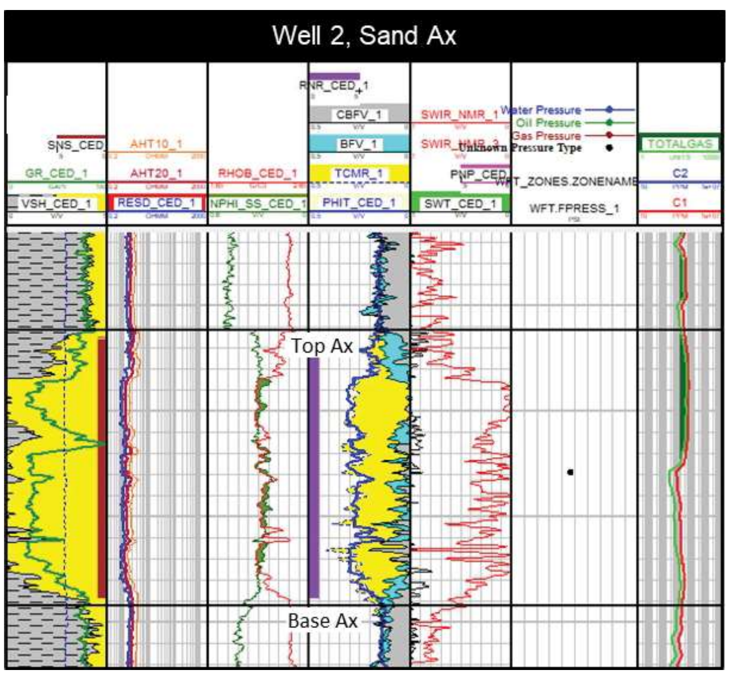

Figure 9: Layout showing logs and interpretation of the deepest A sand encountered by Well 2. Track 1: Vshale and GR, plus sand flags in brown. Track 2: available resistivities. Track 3: neutron and density. Track 4: NMR volumes and computed porosity, plus reservoir flags in purple. Track 5: computed water saturation and irreducible water saturation from NMR, plus pay flags in magenta. Track 7: pressure points. Track 8: gas counts from mud log. The derivation of the flags shown here is discussed in the last section of this paper. Each vertical division equals 5 ft.

where the NMR log was run in Well 2. One sees a dual pattern: lower amount of clay-bound water up to 3-5 porosity units until Vshale reaches 40-50%, then a steeper increase with Vshale, up to 13-15 porosity units. Together with previous observations on the neutron deflection at the sand boundary, this clarifies the presence of two shale types: (1) the "real shale" above 50% Vshale, with high-neutron and high amount of clay-bound water; (2) the mud present in the sand units that mixes with clean sands in the transgressive intervals, with a lower neutron and overall low clay-bound water content.

Ohmm, in order to remove any hydrocarbon saturation "noise" in the shales that the dual water model might otherwise compute. But in this case, if Rwb is selected higher than what the plot suggests, then the amount of gas computed for the boxed points will vanish. It is therefore essential to carefully zone the log analysis process.

Once the Rwb selection is rigorously implemented, the computed saturation matches the irreducible saturation from the NMR log and the gas shows from the mud log. While the addition of gas thickness is minimal in B2 (Fig. 10), it is substantial in B1 (Fig. 11). In the obvious pay

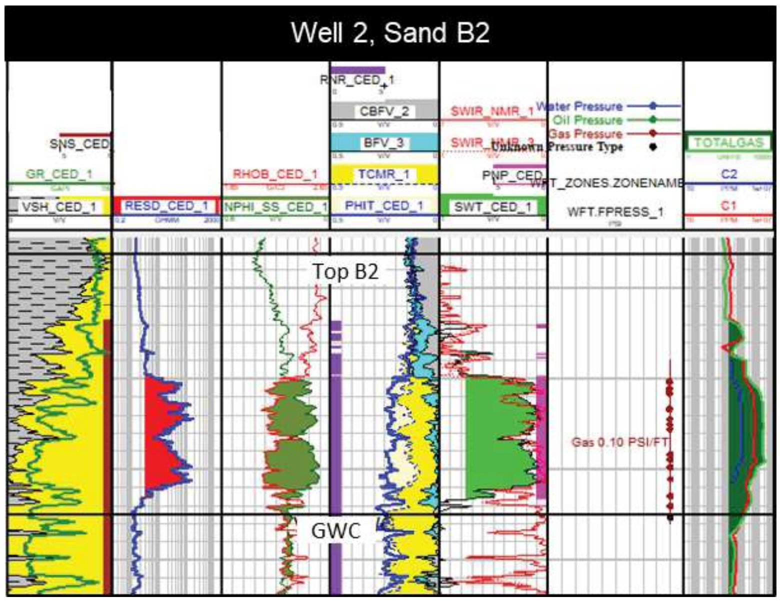

Figure 10: Same as Fig. 9, for the B2 sand in Well 2. Note the NMR porosity deficits.

Those NMR logs illustrate well that the "true shales" mostly contain clay-bound water, while the transgressive muddy intervals above the clean sand sections contain mostly capillary-bound water. This is seen in the top 10 ft of the Ax sand in Fig. 9, the 15 ft just above the B2 gas crossover in Fig. 10, or the 25 ft just above the B1 gas crossover in Fig. 11. While a majority of the pay intervals shown in Figs 10 and 11 is obvious from gas crossovers, it is not so clear there is also gas present in those overlying transgressive intervals. No pressure tests were attempted there, however the gas shows from the mud logs and the NMR saturation indicate gas content.

The way to ensure preservation of gas in the log analysis of the transgressive interval is straightforward. With the dual-water model, the formation water resistivity (Rw) and clay-bound water resistivity (Rwb) can be graphically picked from a Rw apparent plot, as shown in Fig. 12. Note that the transgressive interval appears in the box shown on the figure, very close to the red wet trend. It is common practice to increase Rwb, e.g., to 0.3 Ohmm instead 0.1

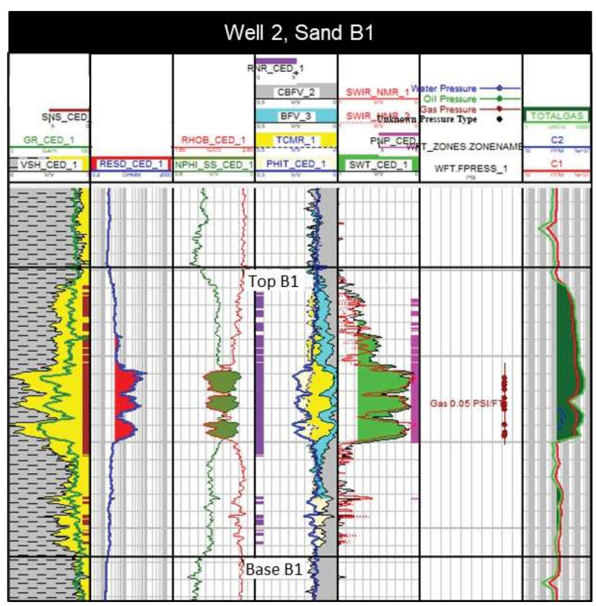

Figure 11: Same as Fig 9, for the B1 sand in Well 2. More NMR porosity deficits.

thickness where neutron and density logs cross over, gas pore thickness accumulates to 18 ft and pay thickness 130 ft. The transgressive interval above that provides 4.3 ft of additional gas pore thickness (24% increase) and 128 ft additional pay thickness (98% increase).

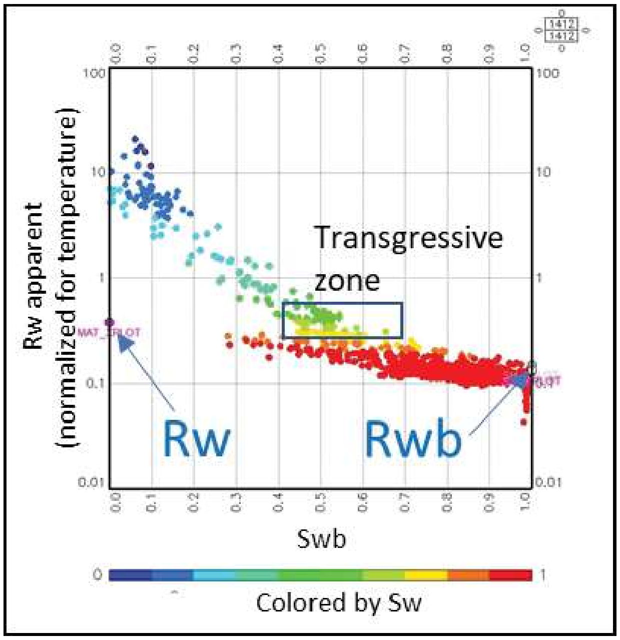

Figure 12: Crossplot of Rwa (Rw apparent) vs. Swb (saturation in clay-bound water) used to pick sand and shale endpoints for the dual-water saturation model in sand B1, Well 2 of Fig. 11. Formation Rw is selected where the trend of red, wet points meets Swb=0. Shale Rwb is selected where it intersects Swb=1. The transgressive zone of B1 appears in the box just above the wet trend.

Moving to Well 1 (Fig 13) where Vshale and porosity were computed from the sonic transforms discussed earlier, we note strikingly similar log responses for sand B1 as in Well 2 (Fig. 11) – except of course for the absence of density, NMR and mud log. This verifies that the dual water methodology holds and correctly populates gas in the same overlying transgression.

Cutoffs

Cross-plotting NMR free fluid volume vs. Vshale and porosity (Fig. 14) produces good first-pass cutoff estimates of Vshale ~50-60% (for sand cutoff) and porosity ~ 12 porosity units (for reservoir cutoff). This is consistent with the earlier observations on Fig. 8, whereby Vshale values above 50% are clay-rich and not as silty as those encountered in the B1 and B2 transgressive intervals.

Then, inspecting the different pay intervals for both wells confirms that wet (therefore tight) intervals between gas

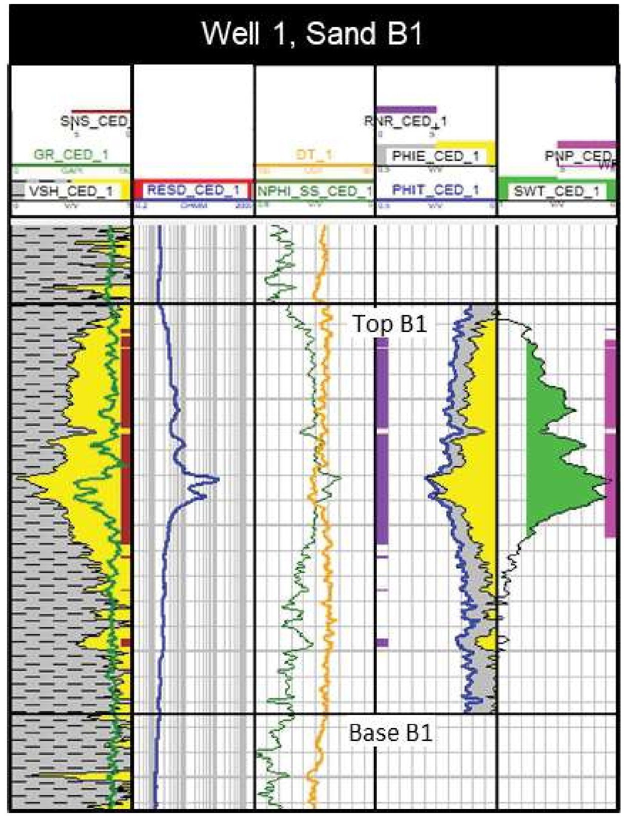

Figure 13: Same as Fig.9, for the B1 sand in Well 1, but without NMR, pressures or mud log. In Track 4, yellow filling represents effective (i.e., not clay-bound) porosity and grey is clay-bound-water porosity stemming from the sand-shale-fluid workflow.

intervals are encountered up to 11% porosity, while gas is encountered starting 12% porosity – as illustrated in Fig. 15. This validates the selection of 12% as the porosity cutoff for those reservoirs.

The pay cutoff deserves more discussion. No pressure measurement, fluid sampling or DST has been attempted across the transgressive intervals discussed so far, so there is no proof of economical flow. Given the mobility of gas, there is a strong likelihood those intervals would contribute to production if they were completed or at least would support the reservoir pressure, but there is uncertainty on actual performance to expect given the expected lower permeability or potential condensate banking. A 75% water saturation cutoff seems to favor the better parts of those interval and penalize the lesser ones, so it seems like a good mid case or best-technical case. If uncertainty was being modeled, a high case would let all the identified gas thickness produce (i.e., using a water saturation cutoff of 80-85%). A low case would penalize those low-quality intervals and employ a water saturation cutoff of 65% or less.

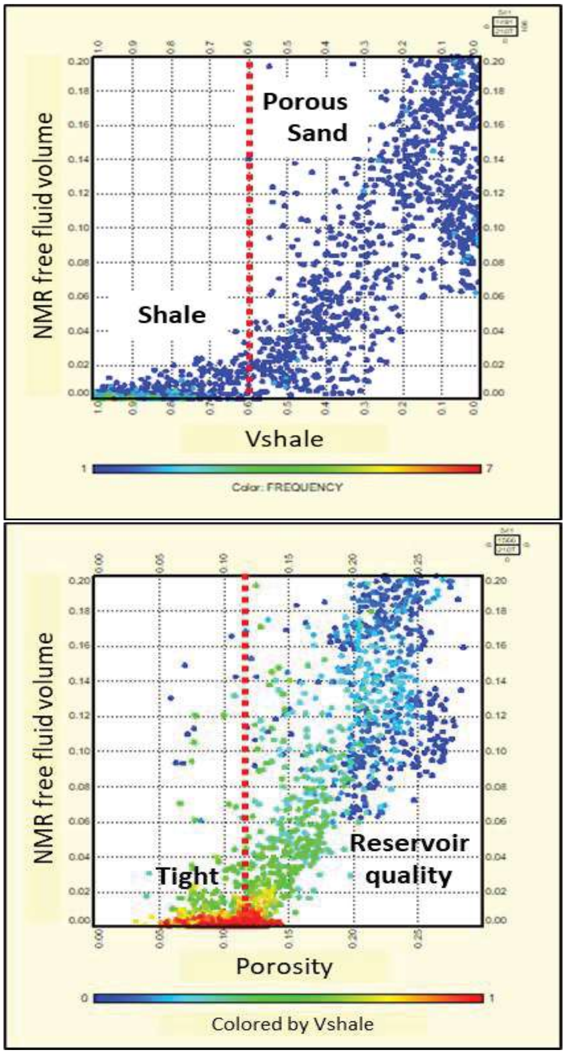

Figure 14: Crossplots of Free Fluid Volume from NMR log vs. Vshale (top) and Porosity (bottom).

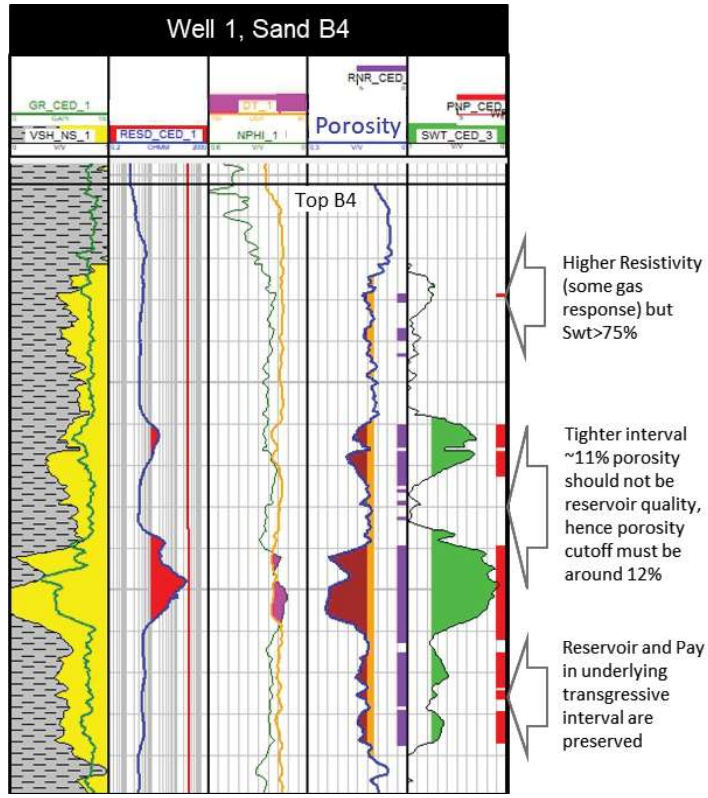

Figure 15: Example of log inspection to validate (or potentially refine) reservoir and pay cutoffs – here using Well 1 across the B4 sand interval. The orange wedge on the porosity log of Track 4 stands for a 11% porosity cutoff while the brown, for 12%.

CONCLUSIONS

Thanks to an NMR log and sonic logs, a consistent volumetric petrophysical model was derived for this DRO. The absence of the density log in critical intervals of Well 1 was mitigated using the sonic log – but the porosity model had to be tuned for the right mud type. It is critical to establish the compaction trend for the field from quality logs, not just to identify erroneous data but also to select among interpretation models for the one that is most realistic.

Transgressive intervals, usually just above or below main pay intervals, were the most challenging to characterize. A neutron-sonic Vshale approach was successfully used in the absence of density, but is highly sensitive to tuning parameters. The gas concealed in those intervals is robustly quantifiable using a dual-water approach that corroborates NMR and mud logs, but this again requires rigorous selection of parameters. Key uncertainties remain concerning producibility of these transgressive intervals and should be a focus for future data acquisition programs as part of field development planning.

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