FIELD EXAMPLE OF ENHANCED HYDROCARBON ESTIMATION IN THINLY LAMINATED FORMATION WITH A TRIAXIAL ARRAY INDUCTION TOOL: A LAMINATED SAND-SHALE ANALYSIS WITH ANISOTROPIC SHALE

Jean-Baptiste Clavaud, Schlumberger, Rick Nelson, BP Egypt
Udit Kumar Guru and Hanming Wang, Schlumberger

ABSTRACT

A fully triaxial multi-array logging tool has been successfully field tested. A forward-model inversion of its response provided vertical resistivity ($R_v$), and horizontal resistivity ($R_h$) in a deep-water turbidite sequence. From the vertical and horizontal resistivity, a laminated sand-shale reservoir model was built in conjunction with nuclear logs and nuclear magnetic resonance (NMR) logs. This process enhanced the hydrocarbon estimation in this low-resistivity pay, and reduced the uncertainty of the gas-in-place assessment. The analysis of the data suggests that shale anisotropy plays an important role in the laminated sand-shale analysis.

The interval in question is a deepwater turbidite levee/overbank deposit, consisting of highly organized thin layers of high-quality gas-bearing sand. Layer thicknesses range from almost a meter to less than a centimeter, with most of the layers in the centimeter range. The original analysis of the data (based on conventional induction tool and a dual-water shaly-sand approach) leads to unreasonably high water saturations.

A laminated sand-shale model where the shales are anisotropic has been built based on $R_v$, $R_h$ values from the triaxial induction tool. This petrophysical model leads to much lower water saturations. The $S_w$ values computed with this second model agree very well with NMR-derived values using diffusion-editing techniques, with analogous core $S_w$ measurements, and capillary pressure data. This field example demonstrates the use of fully triaxial multi-array tool data, and the importance of including shale anisotropy, for the interpretation of low-resistivity pay in laminated sand-shale formations.

Subsequent core description and core analysis have shown that the interpreted section was indeed a high-quality thinly laminated reservoir. Downhole formation-tester data indicated the layers to be in communication, and a drill-stem test confirmed the producibility and gave a minimum indication of the reservoir extent. Mini-permeameter measurements have shown a qualitative similarity between resistivity and permeability anisotropy.

It also shows the beginning of a paradigm shift where we are not focused on detecting the thin beds by increased resolution, but evaluating them quantitatively with the measured bulk anisotropy. Multi-component induction will become a necessary part of an evaluation program in these environments.

INTRODUCTION

Thinly laminated formations can be significant hydrocarbon reservoirs. This is particularly true for turbidite and fluvial environment (Worthington, 1997; Dromgoole et al., 2000; Flolo et al., 2000; Weiss et al., 2001). Often such formations are anisotropic and exhibit the classical “low-resistivity pay” (Darling et al., 1995; Worthington, 2000).

Cause of very large anisotropy of resistivity (larger than 3) has been investigated over the last decade and is due to alternating layers of water-bearing thin beds (shale layers for example) and oil-bearing sand (Klein, 1996; Klein et al., 1997; Schoen et al., 2000; Kennedy and Herrick, 2004).

Intrinsic electrical anisotropy of sandstone (fully brine saturated) has been recently measured between 1 and 2, according to Jing et al. (2002). Similarly, the effect of water saturation upon resistivity anisotropy has been shown in the laboratory to be a major contributor (Clavaud and LaVigne, 2003). This cannot be generalized to all sandstone and shale, and further research is needed particularly in the laboratory.

From the early 1950s to recently, wireline induction tools measured mainly the horizontal resistivity. Consequently, the log analyst when confronted with a potential reservoir containing thinly laminated sand-shale sequence, had to correct the low-resistivity reading. This was usually achieved by adding a shale
contributions term to the resistivity reading using one of the numerous equations published (Worthington, 1985).

The vertical dimension of the problem ($R_v$) can now be evaluated with:
- Logging while drilling resistivity tools, which are sensitive to anisotropy when the apparent angle between the tool and the formation is high (Li et al., 2003).
- Joint inversion of array laterolog and array induction (Faiivre et al., 2000).
- Triaxial induction tool (Moran and Gianzero, 1979; Kriegshäuser et al., 2000; Rosthal et al., 2003; Barber et al., 2004).

Now, the petrophysicist has the possibility of using both the vertical and the horizontal resistivity to tackle this problem (Fanini et al., 2001; Schoen et al., 2001; Shray and Borbas, 2001; Liu et al., 2004). To use resistivity anisotropy for formation evaluation and hydrocarbon computation one would build a laminated sand-shale model with the following workflow:
- Build a two-component volumetric system: sand-shale based on nuclear logs or NMR logs.
- Perform a petrophysical inversion of the resistivity anisotropy in terms of sand and shale resistivity ($R_{sand}$ and $R_{shale}$) where the shale can be anisotropic.
- Conduct a petrophysical interpretation of each individual component (essentially compute $S_w$ for sand and shale).
- Combine the two saturations into a final resistivity anisotropy shaly sand interpretation.

In the remainder of this paper we will build a laminated sand-shale model for resistivity anisotropy in which the shales are anisotropic. We will show the effect of shale anisotropy upon $S_w$ computation. Then we will apply this model to a field log of a fully triaxial induction tool. The formation logged is a low-resistivity pay environment, a fluvial system with thin-bedded sand-shale sequence.

This field example will show the value of triaxial induction measurements, a fast algorithm for tool response inversion, and the need for a robust petrophysical interpretation.

**GEOLOGICAL SETTING**

A fully triaxial induction was tested in a known thin-bedded, low-resistivity-pay formation. The well was logged first with nuclear tools and classic induction tool, then with a fully triaxial induction tool. Core was obtained, and additional core was available on similar wells. Wireline formation pressure and sampling operations and a drill stem test were also performed.

This well encountered two gas-filled channel systems that are separated by a pressure barrier. The upper system consisted of a levee/overbank facies with intervals of very thin-layered sands and shales. The lower system also consisted of levee/overbank facies that was interpreted to be more proximal than the upper channel system (Figure 1).

![Seismic cross section of the formation logged. Cored interval marked in red, $F_{shale}$ in light blue.](image1)

The reservoir portion of these facies consists of highly organized layers of high-quality sand inter-bedded with shales and mudstones. The sand layers in the lower section, being more proximal, are coarser grained with very little mud in the sand layers – conversely the sands in the upper section are slightly finer grained with small amounts of mud. This is reflected in the relative anisotropy readings in the two sections that will be discussed in more detail later.

The cored section is predominantly in the upper channel system. The sealing facies, in the very bottom of the core, penetrates slightly into the lower more proximal system (Figure 2).

![Pressure compartments shown formation tester pretest pressures in light blue, formation tester points which sampled gas in red, cored interval as red block, and drill stem test interval as white bloc.](image2)
TOOL RESPONSE INVERSION

The 1D inversion algorithm (Wang et al., 2003; Barber et al., 2004) of the triaxial induction tool is a fast and rigorous method to determine the formation resistivity anisotropy, formation bed boundary location, and relative dip and azimuth angles (Figure 3). The sensitivity matrix with respect to horizontal conductivity, vertical conductivity, and formation bed boundary locations is computed rapidly with the help of its analytical expression of the sensitivity function in a 1D transverse-isotropic (TI) anisotropic medium.

The relative dip azimuth is solved first by rotating the full matrix measurement. Then an initial model is chosen based on a combination of apparent conductivity for the “XX” coupling and “ZZ” coupling. Finally the 1D code inverts simultaneously the rest of the formation parameters using Gauss-Newton minimization.

The final outputs are: Bed boundaries, beds dip-azimuth, $R_v$ and $R_h$ values.

This code is an order of magnitude faster than those based on a sensitivity function computed using finite difference techniques. Run time is approximately 60 s / 100 ft / array on a 2-GHz PC processor.

THE LAMINATED SAND-SHALE MODEL

Defining the problem

Visualize a formation of thinly laminated high-resistivity isotropic sands at 20 ohm-m, and low-resistivity anisotropic shales with a horizontal resistivity of 1 ohm-m and a vertical resistivity of 2 ohm-m (Figure 4). In vertical and deviated wells, induction tool will measure low-resistivity values (between $R_h$ in vertical well to something between $R_h$ and $R_v$ in deviated well), leading to pessimistic interpretations of hydrocarbon volume.

Here, the thickness of the sand and shale laminations is less than the induction vertical resolution ($\approx$2 ft). When logged in a vertical or deviated well, a regular array induction will measure a value close to the horizontal resistivity, $R_h$. The induction current loops pass through the horizontal layers in parallel. The equation defining the horizontal resistivity, $R_h$, is:

$$R_h = \frac{R_{sand} \times R_{shale-h}}{(1-F_{shale}) \times R_{shale-h} + F_{shale} \times R_{sand}} \quad (1)$$

However, the vertical resistivity read by the triaxial induction tool is defined as:

$$R_v = (1-F_{shale}) \times R_{sand} + F_{shale} \times R_{shale-v} \quad (2)$$

Solving the resistivity problem

The two fundamental equations of the problem (Equations 1 and 2) are what we call the tensor anisotropy model. It is easy to see that the model is under-defined. We have two equations and five unknowns: $R_{sand}$, $R_{shale-h}$, $R_{shale-v}$, $F_{shale}$ and $F_{sand}$. In order to solve the problem we need to bring more information from other sources.

A common technique today for laminated shaly sand is to pick the shale resistivity (both vertical and horizontal) and to solve the problem for $R_{sand}$ and $F_{shale}$ (Fanini et al., 2001; Shray and Borbas, 2001). However we can solve the problem without a formal pick (fixed value) for $R_{shale}$ if we can provide a fraction of shale measurement form nuclear log, NMR logs or borehole image logs.

If we used a volume fraction of shale from a density-neutron interpretation for example, then two unknowns are now fixed ($F_{shale}$ and $F_{sand}$) and are linked by the scalar expression:

$$F_{shale} + F_{sand} = 1 \quad (3)$$
From then the solution to the linear system of equations (1) and (2) is:

\[ R_{\text{shale}} = \frac{R_r + R_h \left(1 - F_{\text{shale}}\right)}{2 \left(1 - F_{\text{shale}}\right)} - \frac{R_s \cdot R_h \cdot F_{\text{shale}}^2 \pm \sqrt{\beta}}{2 \cdot \alpha} \]  \hspace{1cm} (4)

\[ R_{\text{shale-h}} = \frac{R_s - R_h \left(1 - F_{\text{shale}}\right)}{2 \cdot \alpha \cdot F_{\text{shale}}} + \frac{\alpha \cdot R_{\text{shale-h}}^2 \cdot F_{\text{shale}} + \sqrt{\alpha \cdot R_{\text{shale-h}}^2 \cdot F_{\text{shale}} - 1}}{2} \]  \hspace{1cm} (5)

Where \( \alpha \) is the shale resistivity anisotropy (input of the model) and where \( \beta \) is:

\[ \beta = \left[R_r + R_h \cdot (F_{\text{shale}} \cdot (F_{\text{shale}} (1 - \alpha) - 2) + 1) \right] \]
\[ -4 \cdot R_s \cdot R_h \cdot (1 - F_{\text{shale}})^2 \]  \hspace{1cm} (6)

The sign to use in the equations (4) and (5) is dependent upon the value of \( R_h \). Basically, the solution of the polynomial equation requires knowledge of whether the sand is more, or less, resistive than the shale. Again the problem is undetermined. We then use a cut-off value for \( R_{\text{shale-h}} \). If the shale horizontal resistivity is higher than a given \( R_{\text{shale-h}} \) value we need to change the sign in the equations (4) and (5). When the shale are not anisotropic the change of sign occur at \( R_{shale-h} = R_{shale} \), but because the shales are anisotropic the value of the \( R_{shale-h} \) is more complicated:

\[ R_{shale-h} = \frac{\alpha \cdot R_{\text{shale-h}}^2 \cdot F_{\text{shale}} + \sqrt{\alpha \cdot R_{\text{shale-h}}^2 \cdot F_{\text{shale}} - 1}}{2} \]  \hspace{1cm} (7)

So when the \( R_{\text{shale-cutoff}} \) is greater than \( R_{shale-h} \) we must use the sign (+) in equation (4) and (-) in equation (5), and vice-versa when \( R_{\text{shale-cutoff}} \) is smaller than \( R_{shale-h} \).

**Controlling the range of solution**

In some instances, the value chosen for the shale anisotropy \( \alpha \) will not match the log data. For example assume that we have chosen the \( \alpha \) to be 3 and that in one place in the log \( F_{\text{shale}} = 1 \) and \( R_v/R_h = 2 \). One can easily see that in that case the data are falling outside the model (\( \alpha = 3 \)). This issue is addressed by checking the sign of the coefficient \( \beta \) under the square root in the equation (4) and (5). We have found that when \( \beta \) is negative the \( \alpha \) chosen is too high. It also means the result of the square root will be an imaginary number.
To circumvent this we do first compute $\beta$ for each depth with the chosen value of $\alpha$. If $\beta$ is negative, $\alpha$ is too high. We then have to optimize the $\alpha$ value by minimizing the $\beta$ expression (i.e., $\beta = 0$), which leads to an adjusted shale anisotropy:

$$\alpha = \frac{1}{F_{\text{shale}} \cdot R_h^2} \left[ F_{\text{shale}}^2 \cdot R_h \left( \left( F_{\text{shale}} - 1 \right)^2 \cdot R_h + R_v \right) \right]$$

$$-2 \sqrt{ \left( F_{\text{shale}} - 1 \right)^2 \cdot F_{\text{shale}}^4 \cdot R_h^2 \cdot R_v}$$

This new value of $\alpha$ replaces the one that made $\beta$ negative for the computation of $R_{\text{shale}}$ and $R_{\text{sand}}$.

For clarity, an example was built by choosing a 50% shale-sand mixture, where the shale resistivity is 1 ohm·m horizontally, the shale anisotropy is 2 and $R_{\text{shale}}$ is changing from 0.5 to 10 ohm·m. When inverted with $\alpha$ equal to 3, some data (particularly those where $R_{\text{sand}}$ is low) will lead to a negative value for $\beta$. The corrected $\alpha$ values and corresponding $\beta$ values are presented in the Figures 5 and 6.

**Fig. 5:** Optimization of the $\beta$ term by minimization to 0 with respect to $\alpha$. Here $R_{\text{shale}}$ is 1 and $F_{\text{shale}}$ is 0.5.

We acknowledge that this optimized $\alpha$ is probably not the right value for the shale anisotropy. Knowing that the problem is underdetermined one has to find a solution that either matches the data or puts some constraints on the inverted data.

We have tried to obtain a solution for cases in which the data did not match the model by finding the minimal value of $\alpha$ required to match the data. Another possible solution to this problem could have been to make $R_{\text{sand}}$ and $R_{\text{shale}}$ always real and put a lower limit on them.

**Fig. 6:** Optimization of the $\alpha$ term for various $R_{\text{sand}}$. Here $R_{\text{shale}}$ is 1 and $F_{\text{shale}}$ is 0.5.

### Solving the saturation problem

Once the resistivity of each individual component is computed based on $R_v$, $R_h$, $F_{\text{shale}}$, and shale anisotropy $\alpha$, it is easy to use any resistivity to saturation equation to link $R_{\text{sand}}$ and $R_{\text{shale}}$ to their respective saturations:

$$S_{w-\text{sand}} = f_1(R_{\text{sand}}, \phi, \text{electrical parameters}),$$

$$S_{w-\text{shale}} = f_2(R_{\text{shale}}, \phi, \text{electrical parameters}),$$

where $f_1$ and $f_2$ can be any resistivity-to-saturation transform; for example Archie’s equation, Waxman-Smits or the dual water model.

Then a volumetric average of the volume of fluid in each component (sand and shale) leads to:

$$S_{\text{ml}} = \frac{F_{\text{shale}} \cdot \phi_{\text{shale}} \cdot S_{w-\text{shale}} + (1 - F_{\text{shale}}) \cdot \phi_{\text{sand}} \cdot S_{w-\text{sand}}}{F_{\text{shale}} \cdot \phi_{\text{shale}} + (1 - F_{\text{shale}}) \cdot \phi_{\text{sand}}}$$

Furthermore, if the shale porosity and sand porosity are similar then this equation is reduced to

$$S_{\text{ml}} \approx F_{\text{shale}} \cdot S_{w-\text{shale}} + (1 - F_{\text{shale}}) \cdot S_{w-\text{sand}}$$

### THE ROLE OF SHALE ANISOTROPY

We have seen that the shale anisotropy is a parameter of the model. One can ask why do we really need shale anisotropy? To answer this we have done some forward modeling of a laminated sand-shale sequence where the shale is anisotropic. Then the generated $R_v$ and $R_h$ values were inverted without and with anisotropy.
Petrophysical Forward Model

Let’s assume a very simple laminated sand-shale sequence with 50% shale and 50% sand with the same porosity for the shale and the sand. We fix the shale resistivity to 1 ohm-m horizontally and the shale anisotropy to 3. Then we vary the water saturation of the sand from 100% (water sand) to 10% (hydrocarbon-bearing sand). We use a very simple Archie’s law to generate the resistivity of each component (sand and shale) and then use equation (1) and (2) to generate \( R_v \) and \( R_h \).

Petrophysical Inverse Model

From forward \( R_v \) and \( R_h \), we computed \( R_{\text{sand}} \) and \( R_{\text{shale}} \) and using the equations (4 through 8) and then \( S_{\text{wt}} \) using equations (9 through 12). This is done first without shale anisotropy and then with shale anisotropy (\( \alpha \) used was 1, 2 and 3 which is a correct value).

The role of \( \alpha \) upon \( S_{\text{wt}} \) computation

The result of the modeled cased versus inverted data is presented in Figure (7):

- The top picture shows how the saturation in the shale component is affected by shale anisotropy as a function of the sand water saturation originally input in the forward model.
- The middle pictures show the effect on the sand water saturation
- The bottom picture shows the effect upon the total water saturation.

Four sets of curve are presented. The model data are the open black circles. The inverted data are colors: (blue, \( \alpha = 3 \); green, \( \alpha = 2 \); and red \( \alpha = 1 \)). Please note that the jump on the curve is due to the condition at which we switch the sign of the equations in the computation of \( R_{\text{sand}} \) and \( R_{\text{shale}} \) (Equations 4, 5 and 7).

For the shale saturation we can see that neglecting the shale anisotropy will lead to extra hydrocarbon, particularly when the sand saturation is low (transition zone or water sand). This effect is as high as 40% in s.u. and appears when we change the sign in the equations.

For the sand water saturation the situation is more complex. Before the change of sign the hydrocarbon content is over-estimated. After the change the hydrocarbon content is under-estimated.

Finally the total water saturation computed without shale anisotropy will be too optimistic, particularly in the transition zone or a water sand.

From this example it is obvious that neglecting the shale anisotropy will lead to a too-optimistic \( S_{\text{wt}} \). Now one can ask how to choose this shale anisotropy value. Based on the various field tests of the triaxial induction tool, we have found that from a log point of view this value is between 2 and 4.

Nonetheless, this requires local calibration and probably some core measurements. For example, resistivity anisotropy of some North Sea shales have been measured in the laboratory (Cook, 1993). The horizontal and vertical resistivities were measured for various clay porosities, ranging from 40% to 10%. The result shows that \( R_v / R_h \) can be as high as 8 for the more compacted shale (Figure 8). So we must remember that the interpretation of anisotropy resistivity will be greatly influenced by this shale anisotropy. Consequently, in a very shaly zone or in the transition zone the computed \( S_{\text{wt}} \) might be impaired.
FIELD EXAMPLE

Description of the formation logged

This well encountered two gas-filled channel systems that are separated by a pressure barrier. We will now present results obtained in the lower system – the more proximal levee/overbank facies.

The reservoir portion of these facies consists of highly organized layers of high-quality sand inter-bedded with shales and mudstones. The sand layers in this lower channel system, are relatively coarse grained with very little mud in the sand layers.

Conventional analysis using Rh only

We carried out a conventional petrophysical interpretation using regular induction logs and nuclear logs (density-neutron and gamma-ray). This well and formation do not show any noticeable invasion as shown on the regular array induction logs. The regular interpretation is shown in the Figure 9.

The porosity (including clay-bound water) is around 30% to 40%, and the effective porosity (without clay bound water) is around 20% to 30%. The separation between density and neutron shows a high amount of shale except in two or three layers (X150-X155 ft, X188-X192 ft and X268-X271 ft) where the cross over between density and neutron indicates gas. The regular induction log that shows higher resistivity in those places confirms this.

From the induction deep reading we computed an Sw using a dual-water equation (Clavier et al., 1994) to correct for clay conductivity. The resulting Sw values are all close to 1 except in the three depths with higher resistivity.

Once we do the reservoir summation, the net reservoir thickness derived from this conventional analysis is small. Assuming 8% porosity cut-off, 55% for Fshale and 70% for water saturation the net thickness is less than 20 ft for a gross of 160 ft. A summary of the reservoir summation properties is shown in Table 1.

Result of the 1D inversion

Just by looking at the borehole images, it is easy to realize that the cause of the low-resistivity reading in this formation is thin layers of shale with low conductivity (Figure 10). Consequently, this formation and well were good candidates for the triaxial induction tool and the laminated sand-shale analysis.

The vertical and horizontal resistivities, overlaid on top of the borehole image, show a nice agreement between the lamination and the high-resistivity anisotropy (Figure 11). We have displayed the square version of the 1D inversion; it is the default when solving for bed boundaries. This allows us to see that the bed detected by the triaxial induction tool and the 1D code are in good agreement with the borehole image information.

When looking at large amounts of information (hundreds of feet) we decided to present the smooth version of the RV and Rh curves for ease of view. However the Sw computation is not affected significantly if either the square or smoothed curve is used.

Laminated sand-shale analysis using triaxial induction data

A laminated sand-shale model where the shales are anisotropic is built based on RV, Rh values from the triaxial induction tool inverted with our 1D code.

First we must note that the main thin-beded reservoir has high-resistivity anisotropy values and is surrounded by shale at the top and bottom. A little bit further down in this well, we have one massive shale section. In this shale, the anisotropy seems to be between 2 and 3 (Figure 12). Consequently we will use a shale anisotropy (α) equal to 2.5 for the laminated sand-shale analysis. A composite plot of the laminated sand-shale interpretation is shown in the Figure 13.

The input for the fraction of shale was taken from the classical interpretation presented earlier (based on neutron - density and nuclear logs).
The clay to shale conversion is computed with:

$$F_{\text{shale}} = \frac{V_{cl} - \phi \cdot S_{w}}{1 - \phi}$$  \hspace{1cm} (13)

Because the total porosity was similar in the sand section and shale, we did not do any shale distribution analysis (Thomas and Stieber, 1975). The same dual water parameters are used for both the classical and the resistivity anisotropy interpretation.

The very high resistivity anisotropy observed here (up to 20) translate (through the laminated sand-shale analysis) into much lower $S_w$ than with the conventional interpretation with $R_h$ only ($S_w$ in track 6 in the Figure 13). In the main reservoir where this anisotropy is the highest, $S_w$ was about 100% to 80% (except at the depth X155) with the classical and is now between 20% and 50%.

Consequently a new reservoir summation leads to a much smaller number for the average $S_w$ and much bigger number for net thicknesses (see summary on Table 1). Those $S_w$ values where also confirmed by nuclear magnetic resonance diffusion editing logs and core measurements. Finally downhole formation tester confirmed the hydrocarbon presence and the producibility was confirmed by a drill stem test.

**DISCUSSION**

**Comparison with Borehole and core images**

One can ask if the extra hydrocarbon identified with the triaxial induction tool and the laminated sand-shale analysis corresponds somehow to reality. The thinly laminated nature of this reservoir is clearly shown by the borehole resistivity images and the core data. From the borehole images we can see that the bed thickness in much smaller than the vertical resolution of the regular induction tool.

Because this part of the reservoir consists of these highly organized layers of high quality hydrocarbon bearing sands inter-bedded with shales and mudstones this leads to the high anisotropy measured. Furthermore the core taken confirms that the sand layers are around 1 centimeter in this section of the well (Figure 14).
Fig. 10: The borehole resistivity imager in the most right track shows that the higher resistivity read by the regular induction tool (4 ohm·m) is associated with thick resistive bed (>2ft), while the low (1 ohm·m) is associated with thin laminations.

Fig. 11: The borehole resistivity imager in the most right track shows a good agreement with the beds detected by the triaxial induction tool.

Fig. 12: Shale anisotropy is picked from adjacent massive shale where $R_v/R_h$ is between 2 and 3.
**Fig. 13:** Laminated sand analysis results of the triaxial induction tool resistivity anisotropy measurements. Track 1: sand/shale fraction; Track 2: Depth; Track 3: GR column; Track 4: Neutron and density; Track 5: \( R_v \) and \( R_h \); Track 6: \( S_w \); Track 7 and 8: Pay flag for classic and anisotropy interpretation; Track 9 and 10: Fluid volume for classic and anisotropy interpretation; Track 11: Borehole image (resistivity).

**Fig. 14:** From log to borehole images, to whole core, to detailed core picture, the thinly laminated structure of this sand-shale sequence is confirmed.
Comparison between Sw from logs and core data

Some core laboratory capillary pressure curves were obtained on cores from the same formation but on an adjacent well. Using an approach published by Skelt and Harrison (1994), analogous capillary pressure data can be simply arranged in terms of height above the free water level and porosity. The derived capillary pressure results are shown in the Figure 15.

![Figure 15: Derived from the Skelt and Harrison (1994) approach this plot shows the water saturation one might expect for different porosities. We estimate the intervals to be 150m above the free water level, so for 28% porosity we would expect about 22% Sw.](image)

The above data indicate that we should have an Sw less than 30% in the sands or in the net part of our reservoir. Similarly, analogous Dean/Stark direct water saturation measurements (Doorenbos et al., 2001) data show an average of about 26% water saturation in the “net” part of this reservoir. The Sw from the classic interpretation (Rh only) is too pessimistic, while the Sw derived from the triaxial induction tool and the laminated sand-shale analysis (Rv/Rh) is closer to the core values (Table 1).

Comparing resistivity and permeability anisotropy

Some core laboratory permeabilities were measured on some of the core in the upper section. The technique used is mini-permeameter. Based on the point-by-point permeability data we have built a k_h/k_v curve. The k_h curve is estimated by a simple average of the permeability measurements and the k_v curve by a geometrical average. Because of the coarseness of the mini-permeameter data, the k_h/k_v ratio was normalized to a maximum of 20 for this well.

The k_h/k_v ratio is plotted against the R_v/R_h ratio in the Figure 16. We can see that qualitatively the anisotropy of permeability relates to the anisotropy of resistivity as predicted by Klein et al. (1997).

However, we did not have enough measurements to confirm this at a larger scale. Furthermore, permeability anisotropy is sensitive only to the sedimentary/porous network structure, while resistivity anisotropy is sensitive to both the rock and the fluid type. So there are plenty of good reasons for those two ratios not to agree.

![Figure 16: For an upper section of this formation where mini-permeameter data were available, anisotropy of permeability correlates with resistivity anisotropy.](image)

Net pay / gross ratios from logs and core data

Put aside the quantitative computation of Sw, one other benefit of using resistivity anisotropy derived properties is the estimation of net to gross ratio.

We have computed three net pay to gross ratio:
- Using Rh only
- Using R_v and R_h
- Using core data (from the part top part of the reservoir where core were available).

The net to gross is about 50% from the core analysis (visual count). While the net to gross of the classic interpretation is not even close to that (12%) the net pay to gross ratio computed from the resistivity anisotropy is about 45% (summary in Table 1).
Dip and azimuth from the triaxial induction

The result of the 1D inversion provides also dip and azimuth. We have compared those structural dip and azimuth for the reservoir with those obtained from borehole images. The usual tadpole and fan-plot of the dip/azimuth derived form borehole images and triaxial induction is shown in the Figure 17.

Because the structural dip is very low here, we show only a short section were the borehole images dip were more than 5 degrees. It must be noted that the 1D inversion outputs a dip only every 50 feet. In other words, the 1D inversion assumes a constant deep and inverts the 50 feet of log.

Even for such a small dip the agreement between triaxial induction and borehole images dip/azimuth is good (within 2 deg). However, structural dip can change on a much shorter scale than 50 ft and this dip and azimuth will never replace borehole image for a fine analysis of structures and geological features.

Effect of shale anisotropy

As discussed in the previous section, shale anisotropy, if not considered will lead to overestimation of hydrocarbon content. This is particularly true when the resistivity anisotropy is moderate (3 to 5).

To illustrate this we have computed two different volumes of gas with the laminated sand-shale analysis, by setting the shale anisotropy first to 2.5 and then to 1.

The results of the two computations are shown in Figure 18 and summarized in Table 2. We can conclude that in the top of the reservoir the effect is not strong (X150 ft to X200 ft). To the contrary, in places with a moderate $R_b/R_h$ (between 3 and 4), such as found with increased shale content, this effect is important.

One of the big drawbacks of any resistivity anisotropy petrophysical analysis is that it has a tendency to increase the hydrocarbon content dramatically. For this reason, the shale anisotropy effect must always be handled explicitly. Otherwise it will lead to poor reservoir evaluation and management decisions.
CONCLUSIONS

A fully triaxial multi-array logging tool has been successfully field tested in a thinly laminated gas producing formation. Using the vertical and horizontal resistivity, a laminated sand-shale reservoir model was built in conjunction with nuclear logs and NMR logs.

The $S_n$ results obtained using the resistivity anisotropy analysis were in good agreement with core data and local knowledge. Furthermore, this process enhanced the hydrocarbon estimation in this low-resistivity pay, and reduced the uncertainty of the gas-in-place assessment.

The analysis of the data suggests that shale anisotropy plays an important role in the laminated sand-shale analysis. From our preliminary assessment, it seems that shale anisotropy is typically between 2 and 3. However, this must be adjusted locally. Laboratory work is required to better understand the variation from one type of shale to another one. We have also shown that qualitatively the resistivity anisotropy relates to the permeability anisotropy (when the formation is at irreducible water saturation). Furthermore, the structural dip and azimuth computed from the triaxial induction tool were in good agreement with borehole images (within few degrees).

The field test of the triaxial induction was successful in identifying and assessing this thinly laminated sand-shale sequence. The difficulty faced was classical low-resistivity pay with a horizontal resistivity around 1-2 ohm-m for a 30% porosity formation. This leads to very high water saturation estimation in the range of 70%. With the triaxial induction tool and the laminated sand-shale analysis we computed water saturation in the net part of the reservoir about 30%; this agree better with core data (about 22%).

Finally, it seems also important to remind the reader that a good and thorough analysis of such a complex reservoir requires more than resistivity anisotropy. The borehole images and NMR data were key in this interpretation and for understanding the results.

ACKNOWLEDGMENTS

The authors wish to extend their thanks and appreciation to the clients who consented to the use and publication of their data. Many Schlumberger colleagues have also provided solid advice during the development of this work, and their help is gratefully acknowledged.

REFERENCES


Cook, J., 1993: Use of anisotropic electrical resistivity to estimate the state of compaction of a shale, unpublished results.


Faivre, O., Barber, T., Jammes, L. and Vuhoang D., 2000: using array induction and array laterolog data to characterize resistivity anisotropy in vertical wells, SPWLA 43rd Annual Logging Symposium, June 2-5.


Worthington, P.F. 1997: Recognition and evaluation of low resistivity pay, SPE Asia Pacific Oil and Gas Conference, paper 38035, April 14-16.

ABOUT THE AUTHORS

Jean-Baptiste Clavaud is a senior petrophysicist with the Schlumberger Sugar-land Product Center. He received his Ph.D. in geophysics in 2001 from the University of Paris and did some teaching assignment from 1999-2001. In 2001 he joined Schlumberger Doll Research as a senior research scientist. In 2004 he moved to the Schlumberger Sugar-Land Product Center. Beside SPWLA, Jean-Baptiste is also a member of SPE and the Society of Core Analyst. He’s a technical reviewer for those three professional societies.

Rick Nelson is a Petrophysical Consultant for BP. He is currently located in the BP Egypt office in Cairo where he is focused on exploration prospects in the Nile Delta, with emphasis on operations petrophysics, coring and core analysis, seismic rock properties and general petrophysical integration. Prior assignments for BP included BP's London Sunbury campus, where he was working in the Azerbaijan Business Unit, and the Technology Group in Houston involving a variety of projects both domestic and abroad. He has a Bachelor of Engineering Sciences from Johns Hopkins University and has held positions with Schlumberger/Geoquest and Oryx Energy (formerly Sun Oil and now Kerr-McGee). He has authored several SPWLA papers on a wide range of petrophysical topics. He has previously held chapter offices in Dallas and Houston, served on the SPWLA Technology committee and Board of Directors, and presently is Petrophysics Journal Associate Editor.

Udit Guru has an MS in Exploration Geophysics and has over 15 years of experience with a national oil company. Presently he is working for Schlumberger as Petrophysics Domain Champion in Egypt. He is responsible for interpretation development and client support for all Egypt-based clients.

Hanming Wang is a senior engineer with Schlumberger Sugar Land Product Center. He obtained his PhD degree in 1999 from Electrical Engineering Department of the University of Houston. He is interesting in well logging modeling, inversion and log analysis. He is a member of SPWLA, SPE, and SEG.

TABLES

Table 1: Reservoir summation and gross-net computation from $R_s$ only (classic) triaxial induction and laminated-sand analysis, and core-borehole image data (core/image). The symbol <> denotes average values.

<table>
<thead>
<tr>
<th>Model</th>
<th>Classic</th>
<th>Laminated-Sand</th>
<th>Core and Image</th>
</tr>
</thead>
<tbody>
<tr>
<td>Top (ft)</td>
<td>X140</td>
<td>X140</td>
<td>X142.5</td>
</tr>
<tr>
<td>Bottom (ft)</td>
<td>X300</td>
<td>X300</td>
<td>X152.5</td>
</tr>
<tr>
<td>$F_{shale}$ cutoff</td>
<td>55%</td>
<td>55%</td>
<td>#</td>
</tr>
<tr>
<td>$\Phi$ cutoff</td>
<td>8%</td>
<td>8%</td>
<td>#</td>
</tr>
<tr>
<td>$S_W$ cutoff</td>
<td>70%</td>
<td>60%</td>
<td>#</td>
</tr>
<tr>
<td>Gross (ft)</td>
<td>160</td>
<td>160</td>
<td>#</td>
</tr>
<tr>
<td>Net (ft)</td>
<td>19</td>
<td>70</td>
<td>#</td>
</tr>
<tr>
<td>Net/Gross</td>
<td>12%</td>
<td>44%</td>
<td>50%</td>
</tr>
<tr>
<td>Pay $&lt;\Phi&gt;$</td>
<td>28%</td>
<td>25%</td>
<td>30%</td>
</tr>
<tr>
<td>Pay $&lt;S_w&gt;$</td>
<td>60%</td>
<td>35%</td>
<td>22%</td>
</tr>
<tr>
<td>Gas pore thickness (ft)</td>
<td>2</td>
<td>8</td>
<td>#</td>
</tr>
</tbody>
</table>

Table 2: For the main reservoir and an upper section, $R_{sand}$, $R_{shale}$, and $S_w$ are presented for two shale anisotropies (1 and 2.5). The symbol <> denotes average values.

<table>
<thead>
<tr>
<th>Model</th>
<th>Main</th>
<th>Main</th>
<th>Upper</th>
<th>Upper</th>
</tr>
</thead>
<tbody>
<tr>
<td>Top (ft)</td>
<td>X150</td>
<td>X150</td>
<td>X100</td>
<td>X100</td>
</tr>
<tr>
<td>Bottom (ft)</td>
<td>X175</td>
<td>X175</td>
<td>X140</td>
<td>X140</td>
</tr>
<tr>
<td>Shale aniso</td>
<td>1</td>
<td>2.5</td>
<td>1</td>
<td>2.5</td>
</tr>
<tr>
<td>$R_o$</td>
<td>23</td>
<td>23</td>
<td>2.3</td>
<td>2.3</td>
</tr>
<tr>
<td>$R_s$</td>
<td>1.3</td>
<td>1.3</td>
<td>0.7</td>
<td>0.7</td>
</tr>
<tr>
<td>$F_{shale}$</td>
<td>0.35</td>
<td>0.35</td>
<td>0.75</td>
<td>0.75</td>
</tr>
<tr>
<td>$&lt;R_{sand}&gt;$</td>
<td>5.5</td>
<td>4</td>
<td>32</td>
<td>31</td>
</tr>
<tr>
<td>$&lt;R_{shale}&gt;$</td>
<td>0.6</td>
<td>0.38</td>
<td>0.35</td>
<td>0.4</td>
</tr>
<tr>
<td>$&lt;S_w&gt;$</td>
<td>0.4</td>
<td>0.35</td>
<td>0.55</td>
<td>0.9</td>
</tr>
</tbody>
</table>