Abstract

Formation evaluation in thin sand-shale lamination seeks first to determine sand resistivity, volume fraction, and porosity. Afterwards, saturation and volume are simple Archie applications. Resistivity anisotropy techniques can provide estimates of sand resistivity and volume fraction, but good results depend on the choice of the anisotropic shale point. The same shale point should be used in the determination of sand porosity. Difficulties will arise when anisotropy is not caused by sand-shale laminations, when no sand-shale point exists, or when the nearby thick sand-shale is not representative of the sand-shale in the laminations. In producing fields that have undergone several waterfloods, water resistivity is often unknown in the swept thick sands and might not be representative of the water in the unswept thin sands.

As discussed previously, NMR offers useful insights into the petrophysics of thin sand-shale laminations. Typically, 1D high-resolution data is acquired to estimate sand volume fraction, porosity, and permeability, and 3D fluids data is used to evaluate the hydrocarbon type and content in the thin sands. However, shallow depth of investigation, slow logging speed, and sometimes unfavorable signal-to-noise ratios limit the applicability of the NMR technique.

In this paper we first demonstrate the variability of sand resistivity, volume fraction, and porosity output depending on the input parameters. Next, we show the complementary aspects of the resistivity anisotropy and NMR techniques. Since several are the same or determined independently, using both datasets ensures more plausible results in thin beds than either stand-alone technique could provide. Field examples of a straightforward case with a well-defined anisotropic shale point, as well as a difficult case with multiple shale points, are used to demonstrate the new workflow. In general we see improvements in the estimation of the hydrocarbon in place; however, not all thin beds offer large hydrocarbon volumes.

Introduction

The topic of formation evaluation in thin sand/shale laminations has been treated by many authors for the last 30 years. In recent years, we have studied, experimented, applied and refined the interpretation technique for thin sand/shale laminations using both NMR and triaxial induction (3D induction) data on numerous occasions.

To keep the paper readable, we have broken the topic into three parts. First, we discussed the NMR petrophysics in thin sand/shale laminations (Cao Minh and Sundararaman, 2006). Next, we presented a graphical method to analyze resistivity anisotropy in thin sand/shale formations (Cao Minh et al., 2007). Both papers contained many useful references that will not be re-quoted here.

This paper is the third and last in the series. We will show the thin beds workflow using both 3D NMR and 3D induction data. Combining the two dataset provides useful check points to ensure the best possible interpretation in thin sand/shale formations.

A quick review of 3D induction technique is discussed first. The important point is to understand how sand resistivity and sand volume fraction are derived and the effects of the input parameters on the results. Next, we show how to use NMR to verify these two outputs. The third verification is the sand porosity computation. Finally, the fourth and last verification is the volume of hydrocarbon. Although cross-validation between 3D induction and NMR interpretation techniques does not guarantee an accurate evaluation of reserves, it does indicate that the results are plausible.

What we seek first is to be able to say yes, hydrocarbon is indicated by both tools, or no, hydrocarbon is indicated by neither tool. The case to be avoided is having hydrocarbon indication by only one tool. In the latter, we have found that the cause is likely in the choice of input parameters. In many cases, a “yes/no” answer is as important as a “how-much” answer because it allows the operator to test or to abandon the well.

Finally, we use imaging logs/core data to confirm the presence of thin beds.
3D induction technique

Horizontal resistivity, Rh, and vertical resistivity, Rv, are used to derive the sand layer resistivity, Rsand, and the sand layer volume fraction, Fsand (or equivalently the shale layer volume fraction Fshale, via Fsand + Fshale = 1).

Anisotropy discussion

The sources of resistivity anisotropy are: 1) anisotropic shales, 2) thin sand/shales laminations, 3) grain size variation within the sands, and 4) tight calcite streaks intercalations. It is convenient to see these typical points on the crossplot of Rv and Rh (Fig. 1).

![Fig. 1 Points](image)

Fig. 1 Points: 1: anisotropic shale, 2a: pay sand/shale, 2b: non-pay sand/shale, 3: grain-size variation and 4: tight calcite streaks.

1. Shale resistivities uncertainties. Shales are intrinsically anisotropic (point 1). For the pay zone defined by the upper wing of the butterfly chart in Fig. 1, the effects of incorrect shale resistivity parameters (Rshh for horizontal, Rshv for vertical) on Rsand, Fsand are presented in Table 1. “high” gives too optimistic hydrocarbons, while “low” gives too pessimistic hydrocarbons.

<table>
<thead>
<tr>
<th></th>
<th>Rshh low</th>
<th>Rshh high</th>
<th>Rshv low</th>
<th>Rshv high</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rsand</td>
<td>-</td>
<td>-</td>
<td>high</td>
<td>low</td>
</tr>
<tr>
<td>Fsand</td>
<td>high</td>
<td>low</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 1. Shale parameters effects on Rsand, Fsand.

2. Thin sand/shales laminations. The sands could be in pay region defined as Rsand > sqrt(Rshh.Rshv) as shown by point 2a, or in the non-pay region defined as Rsand < sqrt(Rshh.Rshv) as shown by point 2b.

3. Grain-size variations. Clean sands might have grain-size variations between layers. The variation in Rv in such sands will lead to erroneous Fshale indications and result in pessimistic hydrocarbons indications. (point 3).

4. Tight calcite streaks. Same effect as grain-size variations although resistivity values are much higher (point 4).

Other limitations of the resistivity anisotropy technique include the need for porosity logs to determine the sand layer porosity, Phisand, and the knowledge of Archie parameters saturation (a, m, n, Rw). Also, no hydrocarbon-typing and permeability estimation are possible.

There are two ways to solve Rv, Rh equations for the sand layer Rsand, Fsand answers: 1) input shale point (both vertical and horizontal resistivities) and 2) input shale volume fraction Fshale. In the former, the resistivity anisotropy technique is self-contained, i.e., there is no external log is needed. In the latter, external logs are needed to determine Fshale.

Fshale versus Vshale discussion

It is useful to recall the relationship between Fshale and Vshale. From the definitions:

\[
F_{\text{shale}} + F_{\text{sand}} = 1
\]

\[
V_{\text{shale}} + V_{\text{sand}} + \Phi_{\text{e}} = 1
\]

where \(\Phi_{\text{e}}\) is the effective porosity, it follows that:

\[
F_{\text{shale}} = V_{\text{shale}}/(1 - \Phi_{\text{e}})
\]

\[
F_{\text{sand}} = V_{\text{sand}}/(1 - \Phi_{\text{e}})
\]

Thus, Fshale is greater than Vshale. In 100% shales, \(\Phi_{\text{e}}\) is zero, and Fshale equals Vshale. In clean formations, both are zero.

Phisand versus effective porosity \(\Phi_{\text{e}}\), and total porosity \(\Phi_{\text{t}}\) discussion

The sand layer porosity Phisand determined from Thomas-Steiber method deserves comments. An example of Thomas-Steiber crossplot is shown in Fig. 2.

![Fig. 2 Thomas-Steiber crossplot](image)

Fig. 2 Thomas-Steiber crossplot showing the sand endpoint at 30 pu, the laminated shale endpoint at 20 pu, the structural shale endpoint at ~ 45 pu and the dispersed shale endpoint at ~ 5 pu.
On the y-axis, total porosity is plotted. It can be determined from density, density-neutron, NMR, density-NMR or any other method. On the x-axis, shale volume Fshale is plotted. If one uses Fshale that is derived from stand-alone Rv, Rh crossplot such as shown in Fig. 1, only laminated shales are accounted for. If one uses Fshale that is derived from NMR, or Vshale that is derived from GR, density-neutron etc. (after correction for porosity as per Eq. 2), then all laminated, dispersed and structural shales are taken into account. Laminated sand/shales points will plot along the line joining the sand endpoint to the laminated shale endpoint. Dispersed shales and structural shales will tend to their respective endpoints as shown in Fig. 2.

In general, the sand layer porosity Phisand is expressed as:

\[
\text{Phisand} = \phi_t - \sum_{i=1}^{3} F_{\text{shale}_i} \phi_{\text{shale}_i},
\]

where \( \phi_t \) is total porosity, and the indice i loops through the laminated, dispersed and structural shales for shale porosity correction.

Thus, Phisand is the sand effective porosity, and Archie’s equation can be used to compute water saturation Sw.

One can choose to correct total porosity for the laminated shale fraction only (for example by using Fshale derived from stand-alone Rv, Rh crossplot). In this case, Phisand is the sand partial total porosity since it includes structural and dispersed shales porosities.

**Rsand versus true resistivity Rt discussion**

The 3D induction resistivity tensor is rotated and oriented before inversion to give Rh along the bedding planes and Rv perpendicular to the bedding planes, from which Rsand is derived. In deviated wells, conventional Rt derived from resistivity logs must be corrected for dips effect to be comparable with Rsand. On the other hand, at this writing, Rsand is not yet corrected for invasion effect whereas conventional true resistivity Rt is corrected for invasion.

Another consideration is that when Rsand, Fsand are obtained from stand-alone Rv, Rh equations, they represent the sand layer resistivity and volume after laminated shales correction only. If the sands contain dispersed/structural shales, Waxman-Smits or Dual-Water equation should be used in conjunction with the proper Phisand (discussed above) to compute Sw. This is the recommended approach.

Note that solving Rsand with a total Fshale input from GR-density-neutron or NMR that comprises significant dispersed/structural shales in addition to laminated shales will result in low Rsand in very shaly zones (but no effect in moderately shaly zones) in the pay region as seen in Fig. 1.

**3D induction thin bed workflow**

The thin beds workflow using “stand-alone” 3D induction consists of the following steps:

1. Compute Fshale, Phisand from T2 (or T1) distribution. Use Fshale as input to compute Rsand from Rv, Rh equations.
2. Compute fluids type, volumes, saturations from T2, T1, D maps.
3. Estimate permeability.

**NMR technique**

NMR is attractive in thin-beds for many reasons:

1. Thin sand/shales detection with the characteristic bimodal T2 (or T1) distribution.
2. High-resolution NMR T2 (or T1) distribution can be used to determine Fshale, Fsand, and the porosities Phishale and Phisand. In turn, Fshale can be used as external input to Rv, Rh equations to solve for Rsand.
3. Continuous 3D NMR and more recently, 4D NMR data can be used to evaluate hydrocarbons type and occurrence in thin beds.
4. Hydrocarbon ID in thin beds.
5. Permeability estimation.

However, because of the shallow depths of investigation, the main limitations of the NMR technique are near-wellbore effects such as bad holes and invasion. Although thin sand/shales will give a bimodal distribution, the reverse is not true, i.e. bimodal distributions can be seen in other environments such as carbonates or dispersed shaly sands.

**NMR thin bed workflow**

The thin beds workflow using “stand-alone” NMR consists of the following steps:

1. Compute Fshale, Phisand from T2 (or T1) distribution. Use Fshale as input to compute Rsand from Rv, Rh equations.
2. Compute fluids type, volumes, saturations from T2, T1, D maps.
3. Estimate permeability.

**Thin beds workflow using both 3D induction and NMR**

Combining 3D induction and NMR provides four important checkpoints. These are Fsand, Rsand, Phisand and the hydrocarbon volume indication. The combined workflow is exactly the “stand-alone” 3D induction and “stand-alone” NMR workflows reproduced below with the common output highlighted in bold.

- Compute **Fsand, Rsand** from Rv, Rh crossplot with shale resistivities input.
- Compute **Phisand** from density/neutron with Thomas-Steiber method.
- Compute hydrocarbon volume from Rsand, Phisand with Archie equation.
• Compute Phisand from density/neutron with Thomas-Steiber method.
  Compute Phisand from T2 (or T1) distribution.

• Compute hydrocarbon volume from Rsand, Phisand with Archie equation.
  Compute hydrocarbon volume from T2, T1, D maps.

At each step, Fsand, Rsand, Phisand, and the hydrocarbon volume are computed with each tool and crosschecked. The procedure allows validation of parameters picking and ensures results consistency.

Example 1: Shale anisotropy is similar to thin-bedded anisotropy

The first example is shown in Fig. 3.

Track 1 displays the comparison between Phisand computed from NMR with a 9 ms T2 cutoff (labeled as “Phisand NMR”) and Phisand computed from Thomas-Steiber with Eq. 3 (labeled as “Phisand TS”). The same comparison is shown in the 3rd crossplot from the top (far right).

Track 2 displays the density-neutron logs. Between the 2 tracks, a 20 feet section of the oil-based mud imager (OBMI) is shown to show sand/shales laminations in what looks like shales from classical logs.

Tracks 3 and 4 display Rv, Rh and resistivity anisotropy logs respectively. In this example, it can be seen that the shales have the same anisotropy as the thin-bedded sands.

Track 5 shows NMR T2 distribution. Note the free fluid in the laminated sand/shales sections.

Track 6 shows the comparison between Fsand computed from 3D induction (labeled as “Fsand 3Dind”) and Fsand computed from NMR (labeled as “Fsand NMR”). The difference, shaded dark grey, represents either dispersed/structural shales, or wrong parameters input (shale vertical and horizontal resistivities, NMR cutoff). The same comparison is shown in the 2nd crossplot from the top on the far right of Fig. 3.

Track 7 shows the comparison between Rsand computed from stand-alone 3D induction (labeled as “Rsand 3Dind”) and Rsand computed from 3D induction with NMR Fshale input (labeled as “Rsand NMR&3Dind”). The same comparison is shown in the 1st crossplot from the top (far right).

Track 8 displays stand-alone NMR fluids volumetrics at 2.7 in DOI. The NMR hydrocarbon volume (obm+oil) is compared to the 3D induction hydrocarbon volume in track 9. The same comparison is shown in the 4th crossplot from the top (far right). In this comparison, the important point is to verify that hydrocarbon occurrences are indicated by both 3D induction and NMR since the shallow NMR might be affected by invasion. Hydrocarbon volume from classical AIT log is also computed. to show the hydrocarbons gained with newer technology.

The results in this well are summarized in Table 2.

<table>
<thead>
<tr>
<th>400 ft zone</th>
<th>HC-feet</th>
<th>Net/Gross</th>
</tr>
</thead>
<tbody>
<tr>
<td>AIT induction</td>
<td>23</td>
<td>0.34</td>
</tr>
<tr>
<td>3D induction</td>
<td>38</td>
<td>0.62</td>
</tr>
<tr>
<td>NMR</td>
<td>41</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 2. Example 1 results showing an 80% increase in net/gross between 3D induction versus classical AIT induction. The hydrocarbon-feet (HC-feet) values are consistent between 3D induction and NMR techniques.

We conclude that this is a very good well where new technology found substantial increase in reserves.

The anisotropic shale parameters and Thomas-Steiber porosities parameters are shown in Fig. 4. The pay zones are indicated on the graphical analysis of Rv, Rh crossplot by the magenta points. The corresponding depth zones are shown on the left-hand side of the Rv, Rh track in Fig. 3.

Example 2: Multiple anisotropic shales and thin-beds

The second example is shown in Fig. 5. Because the logged interval comprises at least 2 different shales, we divide it into 2 contiguous zones for the analysis.

Track 1 displays the comparison between Phisand computed from NMR with a 9 ms T2 cutoff (labeled as “Phisand NMR”) and Phisand computed from Thomas-Steiber with Eq. 3 (labeled as “Phisand TS”). The same comparison is shown in the 3rd crossplot from the top (far right).

Track 2 displays the density-neutron logs. Between the 2 tracks, 2x10 m sections of the oil-based mud imager (OBMI) are shown to show sand/shales laminations in what looks like shales from classical logs.

Tracks 3 and 4 display Rv, Rh and resistivity anisotropy logs respectively. It can be seen that the shales in the bottom section are more anisotropic than the shales in the top section.

Track 5 shows NMR T2 distribution. Note the free fluid in the laminated sand/shales sections.

Track 6 shows the comparison between Fsand computed from 3D induction (labeled as “Fsand 3Dind”) and Fsand computed from NMR Fshale input (labeled as “Fsand NMR&3Dind”). The difference, shaded dark grey, represents either dispersed/structural shales, or wrong parameters input (shale resistivities, NMR cutoff). The same comparison is shown in the 2nd crossplot from the top (far right).
Track 7 shows the comparison between Rsand computed from stand-alone 3D induction (labeled as “Rsand 3Dind”) and Rsand computed from 3D induction with NMR Fshale input (labeled as “Rsand NMR&3Dind”). The same comparison is shown in the 1st crossplot from the top (far right).

Track 8 displays stand-alone NMR fluids volumetrics at 2.7 in DOI. The NMR hydrocarbon volume (obm+oil) is compared to the 3D induction hydrocarbon volume in track 9. The same comparison is shown in the 4th crossplot from the top (far right). In this comparison, the important point is to verify that hydrocarbon occurrences are indicated by both 3D induction and NMR since the shallow NMR might be affected by invasion. Hydrocarbon volume from classical AIT induction log is also computed to show the hydrocarbons gained with newer technology.

The results in this well are summarized in tables 3 and 4.

| Table 3. Example 2 top section results showing a 70% increase in net/gross between 3D induction versus classical AIT induction. The hydrocarbon-meter (HC-m) values are consistent between 3D induction and NMR techniques. |
|-----------------|-----------------|-----------------|
| 142 m top section | HC -m Net/Gross |
| AIT induction    | 8.2 0.26         |
| 3D induction     | 12.6 0.44        |
| NMR              | 12.5 -           |
| Table 4. Example 2 bottom section results showing a 20% increase in net/gross between 3D induction versus classical AIT induction. The hydrocarbon-meter (HC-m) values are consistent between 3D induction and NMR techniques. |
|-----------------|-----------------|-----------------|
| 163 m bottom section | HC -m Net/Gross |
| AIT induction    | 18 0.47          |
| 3D induction     | 20.6 0.57        |
| NMR              | 21.3 -           |

We conclude that this is a very good well with most of the thin-bedded pay sands occurring in the top section.

The anisotropic shale parameters and Thomas-Steiber porosities parameters are shown in Fig. 6. The pay zones are indicated on the graphical analysis of Rv, Rh crossplot by the magenta points. The corresponding depth zones are shown on the left-hand side of Rv, Rh track in Fig. 5.

Conclusions

Formation evaluation in thin sand/shale laminations is best done using both 3D induction and NMR. Although each tool offers a solution by itself, combining them provides the most robust answers. The integrated workflow relies on the comparison of four important, independently computed outputs in thin beds:

1. Sand layer resistivity, Rsand,
2. Sand layer volume fraction, Fsand,
3. Sand layer porosity, Phisand,

We also discussed the significance of Fshale versus Vshale, Phisand versus Phie and Phit, and Rsand versus Rt.

The workflow is illustrated through 2 examples with increasing complexity. We have shown that in general, 3D induction and NMR improve the estimation of the hydrocarbon in place; however as expected, not all thin beds offer large hydrocarbon volumes.

Acknowledgements

We are grateful to the operators for the permission to use the data shown in this paper. We would like to thank the many reviewers who have helped to improve the readability of this paper.

Nomenclature

Rv Vertical resistivity (ohm-m)
Rh Horizontal resistivity (ohm-m)
Rsand Sand layer resistivity (ohm-m)
Fsand Sand layer volume fraction
Phisand Sand layer porosity
Rshale Shale layer resistivity (ohm-m)
Fshale Shale layer volume fraction
Phishale Shale layer porosity
Rshh Shale horizontal resistivity (ohm-m)
Rshv Shale vertical resistivity (ohm-m)
Phie Effective porosity
Phit Total porosity
Rw Water resistivity (ohm-m)
Sw Water saturation
Rt True resistivity (ohm-m)
Vhc Hydrocarbon volume
T2 NMR transverse relaxation
T1 NMR longitudinal relaxation
D NMR diffusion rate
Vshale Conventional shale volume
Vsand Conventional sand volume

References


Factors

\[ \text{ft} \times 0.3048 \quad \text{E00} = \text{m} \]
\[ \text{in.} \times 2.54 \quad \text{E00} = \text{cm} \]
\[ \text{lbm} \times 0.4536 \quad \text{E00} = \text{kg} \]
**Fig. 3** Example 1 logs and results. Phisand, Fsand, Rsand and HC volumes from 3D induction and NMR are shown and compared.

**Fig. 4** Example 1 – the left crossplot shows the graphical analysis (pay zones in magenta). The right crossplot shows Thomas-Steiber analysis indicating essentially a laminated sand/shale formation in this well.
Fig 5. Example 2 logs and results divided into a top section (top plot) and a bottom section (bottom plot) to account for multiple shale points. Phisand, Fsand, Rsand and HC volumes from 3D induction and NMR are shown and compared in each section.
Fig. 6 Example 2 – the left crossplots show the graphical analysis (pay zones in magenta) for the 2 sections. The right crossplots show Thomas-Steiber analysis for the 2 sections. It can be seen that most the thin-bedded pays lie in the top section.