Laminated Shaly Sand Reservoirs - An Interpretation Model Incorporating New Measurements


ABSTRACT

The measurement of anisotropic properties provides valuable information to accurately characterize shaly-sand laminated reservoirs. A petrophysical model, capable of combining both isotropic and anisotropic formation properties is required for true reservoir characterization. We propose an interpretation model that allows for a joint interpretation of logging data, including NMR, the newly available multi-component resistivity measurements, conventional logs such as gamma ray and density, as well as permeability data from wireline and/or drill-stem formation testing.

The proposed petrophysical model relates the isotropic and anisotropic formation properties with those describing the properties of the sand fraction. The measurements handled by the model consist of total porosity, total shale volume, lithology indicator(s), NMR derived fluid distribution, and formation permeability. The mathematical equations describing the petrophysical model are coupled through a set of carefully selected formation parameters reflecting both the bulk formation properties and the properties of the sand fraction itself.

The combined interpretation of the measurements yields, at each depth level, the relative abundance of shale and sand, the shale distribution: laminar, dispersed, structural and, more importantly, a set of improved reservoir property estimates, including sand effective porosity, sand fluid saturations; both irreducible and movable, and sand permeability. Results from the proposed model reduce reservoir uncertainty and minimize the possibility of missing reservoirs not easily detected using conventional techniques.

The paper describes the mathematical formulation of the petrophysical model as well as the applied numerical techniques. Optimal interpretation results are achieved utilizing forward modeling and a constrained, quality-weighted error minimization technique, which also generates parameter confidence intervals based on a sensitivity analysis. Synthetic and real field data examples are presented showing the ability of the interpretation model to derive the true reservoir character in laminated sand-shale environments.

INTRODUCTION

Numerous authors have described the challenges associated with the evaluation of low resistivity, low contrast laminated sand-shale reservoir. When the thickness of the laminations is significantly less than the vertical resolution of conventional logging instruments, the formation displays a macroscopic anisotropy with respect to properties such as conductivity and permeability. These properties will have different values dependent on the directionality of the measurements with maximum anisotropy occurring when measured parallel and perpendicular to the bedding planes, transverse anisotropy.

In this paper, we build upon the petrophysical models presented by Mollison, et al., 2000 and Mollison and Ragland, 2001. Their petrophysical model for interpreting sand-shale reservoirs is based on the concepts of the volumetric shale distribution model of Thomas and Stieber, 1975, and a tensor resistivity model to determine lamellar shale volume and lamellar sand resistivity. The resistivity tensor utilizes macroscopic electrical anisotropy defined by the combination of the horizontal parallel and vertical series resistivity equations, as discussed by Hagiwara, 1994, 1997, 1998, Klein, et al., 1997, Klein, 1996, and Herrick and Kennedy, 1996, among others. In prior work, the Thomas-Stieber volumetric model utilizes total porosity and shale volume and thus only allows for calculating shale distributions in terms of either a lamellar-structural or lamellar-dispersed system.

We propose a petrophysical model that simultaneously incorporates all volumes of distributed shale, lamellar, structural, and dispersed, in the corresponding instrument response equations (total porosity, total volume of shale, density, neutron, etc.). A simultaneous solution of these equations allows us to account for the different combinations of shale distribution defined by the volumetric and tensor models to derive the laminaire sand reservoir properties. The combined model and simultaneous solution also allow the estimation of errors in the results originated by either inadequacy in the model or errors in the parameter selection. The proposed model also allows for incorporating other measurements such as those derived from NMR (BVI, BVM, CBW). The incorporation of NMR further results in the separation of estimated NMR further results in its
irreducible and moveable components and deriving a more accurate estimate of sand permeability using the Coates-Timur (Coates et al., 1991) permeability equation. If available, permeabilities from Well Formation Test analysis are also integrated, resulting in a self-consistent interpretation of all available data.

PETROPHYSICAL MODEL

What follows describes in more detail the proposed petrophysical model.

Volumetric Model

The volumetric petrophysical model used in this work for a laminated shaly-sand formation is depicted in Figure 1, with the main rock components being laminar shale and sandstone. The laminar shale portion of the rock shows the volumes of dry laminar shale and its associated bound water. The laminar sandstone portion of the rock shows the volumes corresponding to sand matrix, consisting of sand grains; structural shale consisting of dry structural shale and associated bound water; dispersed shale consisting of dry dispersed shale and associated bound water; and effective porosity containing irreducible water and movable fluids consisting of either or both water and hydrocarbon. Assuming a unit volume of rock, the volumes of each of the components described above must add to one. We can write the equation for the bulk volume components as,

\[ V_{ma} + V_{shl} + V_{shs} + V_{shd} + V_w + V_{hc} = 1. \]  (1)

To avoid interpretation errors, it is important to clearly differentiate between bulk volumes, referred to as a fraction of the total rock, and the ‘laminar sand referenced’ volumes, referred to as the laminar sand fraction of the binary rock normalized to 100% sand volume. Throughout the text, we will use the subscript ‘sd’ to refer to the sand referenced volumes. Using this convention, we can write the equation for the laminar sand fraction components using the sand referenced volumetrics as,

\[ V_{msd} + V_{shsd} + V_{shd} + V_{wd} + V_{hcld} = 1. \]  (2)

As an example, the volumetric relationship of sand referenced and bulk dispersed shale volume is given by,

\[ V_{shd} = V_{shd}(I-V_{shl}). \]  (3)

As in the Thomas-Stieber volumetric shale distribution, the model assumes a constant maximum porosity associated with the sandstone portion of the rock, which can be only filled with dispersed shale and fluids, i.e., water and hydrocarbon. Structural shale can only be present as a replacement of the sand grains. Laminar shale replaces the sandstone portion of the rock, including all its components, i.e. quartz, dispersed shale, structural shale, and fluids.

To honor the shale-sand replacement laws in the model, we need to introduce two additional equations: the first one considering the replacement of sandstone porosity with dispersed shale, the second one considering the replacement of sandstone grains with structural shale. Both laws take into account the volume of sandstone replacement with laminar shale and can be written as,

\[ \phi_{max}(I - V_{shl}) = V_{shd} + V_w + V_{hc}, \]  (4)

which establishes that the available rock pore volume can only be occupied with dispersed shale and fluids, and

\[ (I - \phi_{max})(I - V_{shl}) = V_{shs} + V_{sd}, \]  (5)

which establishes that the available matrix volume can only be occupied with quartz grains and structural shale.

The replacement laws introduce range constraints on dispersed and structural shale volumes given by,

\[ 0 \leq V_{shd} \leq \phi_{max}(I - V_{shl}), \]  (6)

and

\[ 0 \leq V_{shs} \leq (I - \phi_{max})(I - V_{shl}), \]  (7)

respectively.

In order to define the rock total porosity, it is necessary to consider the volumes of bound water associated with each of the components of the shale distribution. Considering that each shale type could have different porosities, we can then write,

\[ V_{wshl} = \phi_{shl}V_{shl}, \]  (8a)

\[ V_{wshs} = \phi_{shs}V_{shs}, \]  (8b)

and

\[ V_{wshd} = \phi_{shd}V_{shd}, \]  (8c)
Based on the above definitions and considerations, we can express total porosity and total shale volume as,

$$
\phi_t = V_{wshl} + V_{wshs} + V_{wshd} + V_w + V_{hc}
$$

(9)

and

$$
V_{shl} = V_{shl} + V_{shs} + V_{shd},
$$

(10)

respectively.

Substituting water and hydrocarbon volumes along with shale bound water volumes in Equation (9) with the corresponding expression given by equations (4) and (8) and rearranging terms, the total porosity equation can be written as,

$$
\phi_t = \phi_{max} - (\phi_{max} - \phi_{shl})V_{shl} - (1 - \phi_{shd})V_{shd} + V_{shs} \cdot V_{shs}.
$$

(11)

As we will show later, Equations (10) and (11) play an important role in the shaly-sand interpretation model proposed in this work.

**Petrophysical Interpretation Model**

The petrophysical interpretation model consists of a set of equations relating the measured macroscopic properties of the rock (such as the total volume of shale, total porosity, density, and the bulk volume of irreducible water) with the macroscopic petrophysical rock properties (such as the volume of irreducible water, the volume of hydrocarbon, and the three shale volumes). This allows one to write a set of equations that can be simultaneously solved for rock petrophysical parameters once a given set of rock measurements are provided.

What follows describes a model consisting of total porosity, total volume of shale, density, neutron, gamma ray, acoustic, vertical and horizontal resistivities, bulk volume irreducible water, bulk volume movable fluids, clay bound water, and vertical and horizontal permeabilities.

When sufficient information is available, five fundamental, independent rock petrophysical parameters can be estimated through the interpretation process:

- Volume of laminar shale,
- Volume of structural shale,
- Volume of dispersed shale,
- Volume of irreducible water, and
- Volume of movable water.

The other volumes, those of hydrocarbon and sand, are calculated from Equations (1) and (5), respectively, once the fundamental parameters are calculated. Other volumetric properties such as total porosity, effective porosity, and fluid saturation, and rock physical properties such as resistivities and permeabilities can also be derived from the five fundamental ones.

It is important to note that, although these measurements reflect macroscopic properties of the rock, they can be translated into intrinsic sand properties, i.e., those of the sand fraction, through the interpretation process.

**Porosity and lithology indicators**

In order to relate the log measurements with the rock petrophysical parameters, we consider a model consisting of a volume-weighted average of the individual species properties. Also, to provide generality, we use the letter $P$ to indicate a generalized property, such as rock density, which can then be written as,

$$
P = P_{sd}V_{sd} + P_{shl}V_{shl} + P_{shs}V_{shs} + P_{shd}V_{shd} + P_wV_w + P_{hc}V_{hc}.
$$

(12)

In this work, we have used Equation (12) to represent the responses of Gamma Ray, Neutron, Density, and Acoustic instruments. The interpretation model also accepts analyst-derived estimates of total volume of shale and total porosity as macroscopic measurements that can be integrated with any other available porosity and lithology indicators. Equations (10) and (11) are used for that purpose.

**Resistivity indicators**

The 3DEXSM instrument provides multi-component induction measurements that allow for the derivation of a resistivity tensor at each logging depth. Specifically, it allows for estimating the resistivities in the directions parallel, $R_p$, and perpendicular, $R_t$, to the bedding plane (lamination). The combination of both resistivities improves the ability to characterize the actual reservoir by a more accurate estimation of the intrinsic sand properties (porosity and fluid saturations).

The tensor model resistivity response equations are,

$$
\frac{I}{R_h} = \frac{V_{shl}}{R_{shl,h}} + \frac{(1 - V_{shl})}{R_{sd}},
$$

(13)
for the horizontal resistivity, and
\[ R_h = V_{shl} R_{shl} + (1 - V_{shl}) R_{sd} \quad (14) \]
for the vertical resistivity.

The Waxman-Smits, 1968, saturation equation is used to evaluate the sand resistivity in Equations (13) and (14),
\[ R_{sd} = \frac{a R_w}{\phi_{sd}^n (1 + R_w B Q_{sd} S_{wlsd}^{-1}) S_{wlsd}^n} \quad (15) \]

The cation exchange capacity per unit pore volume, \( Q_{sd} \), of the sand dispersed shale is calculated using the Hill, Shirley, Klien, 1975, equation and the Waxman-Smits ion mobility constant, \( B \), is calculated using the Juhasz, 1986, equation.

Although the model considers the volumetric aspects of all shale components, it is important to note that, at this stage of the work, we are not considering the electrical conductivity effect of structural shale on the resistivity equation. Only the laminar shale (parallel conductivity) and the dispersed shale effects are considered. However, as we will see later, the incorporation of tensor resistivity into the model allows us to discriminate among the various shale types, even if the shale components have the same properties.

**Water and hydrocarbon indicators**

The model also considers macroscopic measurements derived from Nuclear Magnetic Resonance (NMR) instrument, such as total porosity, bulk volume irreducible, BVI, bulk volume movable, BVM, and clay bound water, CBW. The petrophysical model dealing with the bulk volumes is then expressed as,

\[ \text{BVI} = V_{wirr} \quad (16) \]

\[ \text{BVM} = V_{wm} + V_{hc} \quad (17) \]

and

\[ \text{CBW} = \phi_{shl} V_{shl} + \phi_{shs} V_{shs} + \phi_{shd} V_{shd} \quad (18) \]

The incorporation of at least BVI or BVM to the resistivity equations permits the separation of the total volume of water into its irreducible and movable components. In addition, knowledge about irreducible and movable fluids brings the possibility of estimating a formation permeability index by using the Coates-Timur equation.

**Permeability indicators**

When available, the petrophysical model allows for incorporating horizontal and vertical permeabilities in the same fashion that resistivities are used. To derive horizontal and vertical macroscopic permeabilities, we combine the intrinsic sand values using parallel and series models, resulting in the following expressions,

\[ k_v = V_{shl} k_{shl} + (1 - V_{shl}) k_{sd} \quad (19) \]

and

\[ \frac{1}{k_h} = \frac{V_{shl}}{k_{shl}} + \frac{(1 - V_{shl})}{k_{sd}} \quad (20) \]

for the vertical and horizontal permeabilities, respectively. In both equations, we calculate the sand permeability using the Coates-Timur (Coats et al., 1991) equation,

\[ k_{sd} = \left( \frac{\phi_{sd}}{C} \right)^b (\text{BVI}_{sd} / \text{BVM}_{sd})^b \quad (21) \]

**Reference model**

The concept of stabilization incorporates a ‘reference’ model, consisting of the volumes of laminar shale, dispersed shale, structural shale, and irreducible and movable water volumes. The reference model is normally considered as the solution obtained at the previous depth level, acting as smoothness constraints.

The set of equations characterizing the reference model is expressed as follows,

\[ V_j = V_j \bigg|_{\text{ref}} \quad (22) \]

with \( j \) varying over the set of parameters.

**Constraints**

Range constraints are added to the system to obtain results that fall within the range of possible physical values. For example, Equations (6) and (7) are incorporated into the system of equations to limit the volumes of structural and dispersed shale as a function of laminar shale,
\[ 0 \leq V_{shd} \leq \phi_{max} (1 - V_{shl}) , \]  
(6)

\[ 0 \leq V_{shs} \leq (1 - \phi_{max})(1 - V_{shl}) . \]  
(7)

In addition, the volume of hydrocarbon must satisfy the following range constraint,

\[ 0 \leq V_h \leq \phi_{max} (1 - V_{shl}) - (V_w + V_{shd}) . \]  
(23)

**Solution of the System of Equations**

The system of equations is simultaneously solved using a Nonlinear Weighted Regularized Least-Squares Method, i.e., we define the solution to the problem as the set of parameters that minimizes a weighted error function involving the data match, constraints, and a reference model, defined as,

\[
H(\vec{p}) = \left| W_d (f(\vec{p}) - \vec{d})^2 + W_c (g(\vec{p}) - \vec{h})^2 + W_p (\vec{p} - \vec{p}_{ref})^2 \right|, 
\]  
(24)

where \( W_d, W_c, \) and \( W_p \) represent the weighting matrices associated data, constraints, and reference model, respectively, and \( \vec{p} \) the solution parameter vector, consisting of the laminar shale volume referred to the rock volume, the dispersed shale volume, the structural shale volume, the irreducible water volume, and the movable water volume, the last four referred to sand volumes.

A Newton iterative process is used to obtain the solution of the nonlinear problem. The linearized system of equations is solved using the Marquard-Levenberg technique combined with the Singular Value Decomposition method (Mezzatesta et al., 1994, Mezzatesta, 1996).

Although the proposed technology neglects the conductivity effect of structural shale, it provides a computational framework for future improvements. These enhancements will come, for example, from more sophisticated water saturation equations and from new ways of interpreting NMR measurements.

**GENERATION OF SYNTHETIC DATA**

A synthetic earth model is generated with layers of random thickness, which vary from a minimum of two samples to a maximum of two hundred samples. Assuming a sampling rate of 80 samples/meter, the corresponding thickness is 2.5 cm for the thinnest layer(s) and 2.5 meters for the thickest layer(s). These randomly generated layers are organized so that the thick-sands with thin-shales are at the top of the data set and progress into thin-sands with thick-shales at the bottom of the data set.

Petrophysical properties are assigned to the sand and shale layers. For the sand layers, we also define the fluid content, amount of dispersed shale and amount of structural shale. The resistivity of the sand layers is computed from the fluid saturation, using the Waxman-Smits equation, assuming values of formation water resistivity, salinity, and values for the exponents.

To generate synthetic conventional logs (Gamma Ray, Bulk Density, Compressional Slowness, Neutron Porosity, etc.) and NMR derived measurements (BVI, BVM, CBW, etc.), the formation is "logged" assuming a Gaussian tool response function of 121 samples (1.5 meters, 4.9 feet).

In addition, the 3DEX device is forward modeled to generate the corresponding electrical fields. These fields are processed by inversion (Yu, et al., 2001) to generate the formation vertical resistivity, \( R_v \), and the horizontal resistivity, \( R_h \).

The process results in a coherent set of log responses corresponding to the measured "macro" properties of a laminated formation, which consists of approximately 500 layers covering 180 meters. Figure 2 shows the synthetic data set used for this paper. It also serves as a validation of the 3DEX forward model, the inversion procedure and the interpretation.

The first track on the left, displays an end-of-layer curve indicating the highly laminated earth model. Also displayed are the anisotropy computed by inversion and the anisotropy computed directly from the earth model. Anisotropy reaches a maximum value in the neighborhood of 140 meters where the sand-shale ratio is close to 50%. Towards the top of the data set there is a predominance of sand and towards the bottom there is a predominance of shale, decreasing the anisotropy in both cases.

The second and third track from the left shows the electrical fields computed with the 3DEX forward model. The high activity of the XXHI field is indicative of its sensitivity to the resistivity contrast at layer boundaries. The lazy appearance of ZZHI is a close approximation to the response of conventional induction measurements.

The fourth track from the left shows, in red, the earth model squared resistivity using 1 ohm.m for the shales.
and 19.779 ohm.m for the sands. Also displayed in blue is the sand resistivity computed by the interpretation program. We can see that, regardless of the sand to shale ratio, the interpretation program yields a value of sand resistivity very close to that of the earth model.

The next to last track from the left, shows the vertical resistivity and the horizontal resistivity computed by the inversion program along with the ones computed directly from the earth model. Again, we observe a very close agreement between corresponding resistivities. Density, Neutron, and Gamma Ray logs, generated by "logging" the earth model are shown in the last track on the right.

VALIDATION OF THE PETROPHYSICAL MODEL

A number of different cases were used to validate the method and to have an initial understanding of how errors in the selection of parameter or in the selection of the interpretation model may affect the results.

Table 1 presents the results from all considered cases. Four different sets of conditions where investigated; 1) Reference Case, 2) computations ignoring structural shale, 3) computations made assuming that the dispersed shale has a water content larger than the one used to generate the data, and 4) computations made assuming that the dispersed shales have a water content smaller than the one used to generate the data.

In all four cases, we assessed the quality of the computations by comparing the computed cumulative sand and oil volumes to the volumes computed from the earth model (base case truth). For the reference case, we also present the comparison between the earth model sand resistivity and the average computed sand resistivity.

Reference Case

We generated 36 different earth models by varying the amount of structural and dispersed shales in the sand layers. The different combinations of dispersed and structural shale volumes used to generate the earth models, as well as, the results of the computations are presented on the left side of the Table 1. There is very good agreement between the expected values of sand resistivity, cumulative sand volume, and cumulative oil volumes and their corresponding computed values. This example demonstrates that it is possible to accurately estimate the properties of the sand layers from macroscopic measurements responding to both sand and shale layers.

Computation ignoring structural shale

It can be seen that the assumption that the formation does not contain structural shale, produces very optimistic cumulative sand values but does not introduce excessive error in the computed cumulative oil volumes. Again, note that in these calculations we disregarded the effect of the structural shale on the resistivity response. The Waxman-Smits saturation model is only defined for dispersed clay/shale and thus ignores the effect of structural shale. Further research will be required to quantify this effect.

Computations assuming different dispersed shale parameters

A common parameter selection problem is determining which shale properties to use. Typically, the properties of the massive shales adjacent to the zone of interest are used., however, these shales may have different properties than the dispersed clay/shales within the sands. Our examples, even though they do not contribute to improved parameter selection, serve to quantify expected errors. The highlighted row, assumed to be a case of common occurrence, 10% dispersed shale and 1% structural shale, shows an average cumulative oil error of approximately 11% for a ±40% variation in the dispersed shale water content. Increasing the quantity of dispersed shale increases the expected error.

FIELD EXAMPLE

Figure 3 shows the application of the proposed technology to a real case. From left to right, the first track shows the Gamma Ray log, Caliper, and the resistivity anisotropy ratio derived from inversion of the 3DEX data. The second track shows the horizontal and vertical formation resistivities, also derived from 3DEX data, as well as the resistivity and permeability of the sand portion of the rock, both derived from the integrated interpretation process. The third track shows the Density and Neutron logs and the fourth track displays a set of water saturation curves (sand total and effective in blue and rock total in red). Finally, tracks five and six show the volumetric distribution for the total formation and the laminar sand fraction, respectively.

The selected interval from the well might be of little interest if it were analyzed with traditional ‘bulk shale’ models. Density and neutron log data appears to be the result of high shale content and the horizontal resistivity values of only 1-1.2 ohm.m, may not trigger the analyst’s interest in this section. Only the Gamma Ray shows a small decrease in value towards the bottom of the section indicating a possible increase in sand content.
Applying the proposed model to this highly laminated section, we see that it is composed of sand-shale layers with the reservoir quality of the sands decreasing toward the top of the log section. The decreasing sand resistivity and resulting increase in water saturation is directly related to the increase in dispersed shale volume.

The analysis of this section results in a cumulative net sand of 12.04 feet and a cumulative oil volume of 6.63 hydrocarbon-feet. Sand permeability index computed with the Coates-Timur equation indicate that this section is potentially productive.

CONCLUSIONS

A petrophysical model for laminated shaly-sand formations incorporating standard and tensorial macroscopic measurements has been developed and implemented in a software module. At each depth level, the model allows for a fully integrated interpretation of all available data, leading to accurate and internally consistent estimates of the intrinsic reservoir properties, specifically the saturation, porosity, and permeability of the laminated sands, as well as shale distribution. The description of the sand component not only contributes to a better estimation of hydrocarbon volumes, but also to a realistic estimation of sand permeability.

The proposed technology provides a computational framework for future improvements, such as considering more sophisticated water saturation equations, new ways of interpreting NMR measurements, and multi-mineral situations.

Synthetic macroscopic log responses generated over a set of benchmark models covering a large number of shaly-sand laminations cases provides a validation of the interpretation methodology. Through this validation, we demonstrate that it is possible to derive intrinsic sand laminae properties from the measured formation macroscopic properties. The benchmark models also provide a data set that allow for the quantification of error in hydrocarbon volume as a result of neglecting structural shale occurrence and/or dispersed shale parameter errors.

A field case is presented as an application of the proposed interpretation model and demonstrates its practicality.

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REFERENCES


**NOMENCLATURE**

**General**

- \( \text{B} \) = constant, Waxman-Smits eq
- \( \text{BVI} \) = bulk volume irreducible
- \( \text{BVM} \) = bulk volume movable fluids
- \( \text{C} \) = constant, Coats-Timur permeability eq
- \( \text{CBW} \) = clay bound water
- \( k \) = permeability
- \( P \) = generalized rock property
- \( \text{Q}_v \) = CEC/unit pore volume, Waxman-Smits eq
- \( R \) = resistivity
- \( S_{wl} \) = total water saturation
- \( V \) = volume
- \( \phi \) = porosity

**Subscripts**

- \( e \) = effective
- \( irr \) = irreducible
- \( \text{hc} \) = hydrocarbon
- \( mv \) = movable
- \( \text{ref} \) = reference
- \( \text{shd} \) = shale dispersed
- \( \text{shl} \) = shale laminar
- \( \text{shs} \) = shale structural
- \( \text{sd} \) = sandstone
- \( t \) = total
- \( w \) = water
- \( h \) = horizontal
- \( v \) = vertical

**Exponents**

- \( m^* \) = Waxman-Smits porosity exponent
- \( n^* \) = Waxman-Smits saturation exponent
- \( a \) = porosity exponent, permeability equation
- \( b \) = bulk vol ratio exponent, permeability eq
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Alberto G. Mezzatesta received a M.Sc. degree in Petroleum Engineering from the National University of Cuyo, Argentina, and a Ph.D. degree in Chemical Engineering from the University of Houston, Houston, Texas. Alberto joined Dresser Atlas in 1984 (now Baker Atlas), Houston, and held several positions within Research, Engineering, and Interpretation Development. Previous to this, he worked for the national oil company in Argentina, YPF, and as a professor at various universities. Currently, he holds the position of Manager, Research and Engineering within the Baker Atlas Geoscience department. He is author and co-author of several publications and patents in the areas of borehole geophysics, data integration, inversion methods, and instrument design. He is an active member of the SEG, SPE, and SPWLA.

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![Fig. 1: Sand-shale laminated volumetric model, showing the volumes associated with each individual rock component.](image-url)
Table 1: Benchmark model results. The first eight columns show the results of the reference case used to validate the technique. The six columns on the right show the cases of ignoring structural shale and using different dispersed shale parameters for the interpretation.

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Fig. 2: Synthetic data set used for validation of the interpretation process. The first track on the left, displays an end-of-layer curve indicating the highly laminated earth model. The 3DEX calculated responses are presented in tracks two and three. Also displayed are, the anisotropy computed by inverting the 3DEX data and the anisotropy computed directly using the parameters of the earth model. The anisotropy reaches a maximum value in the neighborhood of 140 meters where the sand shale ratio is close to 50%.
Fig. 3: Application of the proposed technology to data from a deep-water well in the Gulf of Mexico. The last two tracks on the right show the results of the interpretation in terms volumes referenced to the formation and the sand fraction. The selected interval from the well might be of little interest if it were analyzed with traditional 'bulk shale' models. Density and neutron log data appears to be the result of high shale content. The horizontal resistivity values around 1.0 ohm.m may not trigger the analyst’s interest in this section. Although a highly laminated section, the derived sand permeability profile, second track from the left, indicates good potential production.