

Petroleum-Gas University of Ploiesti



PhD Thesis

Contribution to Thin Bed Petroleum Reservoir Characterization

PhD Student

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Due to the fact that there has not been new considerable exploration in conventional reservoirs and also because of advancement in technology and high oil prices, evaluation and development of unconventional reservoirs has become a serious issue in last decade.

Unconventional reservoirs generally involve shale oil & gas, tight reservoirs, low resistivity pays, etc. Low resistivity pays are the formations in which deep resistivity reads low but when formation is put on production, it produces water free hydrocarbon.

Low Resistivity Pay (LRP) Reservoirs include:

- Fractured Reservoirs
- High Capillary Facies e.g. Packstones, Micrites, etc.
- Presence of Paramagnetic Minerals as Pyrite, etc.
- Deep Invasion of Saline Water Based Mud
- Thin Bed Lamination of Sand Shale

A typical case of low resistivity pay - although not limited to – is thin bedded sand and shale alternation. When sand layer thickness falls below log resolution, true response of sand cannot be captured and it looks like a shaly sand on log; resistivity reads like shale so with normal log evaluation ; thin bed sand interval would be considered as non-reservoir.

An important aspect of most reservoir assessments is the determination of original hydrocarbons in-place (OHIP). For an oil reservoir, the original oil-in-place (OOIP) at surface conditions can be determined from the volumetric equation:

$$\begin{aligned} OOIP &= A \cdot h \cdot \phi \cdot (1 - S_{wi}) / B_{oi} && \dots\dots\dots \text{Equation 1.1} \\ OOIP &= A \cdot HPT / B_{oi} \end{aligned}$$

where

OOIP = original oil-in-place [stock tank barrels, stb];

A = gross reservoir area [ac];

h = average oil-bearing rock thickness [ft];

ϕ = average total porosity of oil-bearing rock [frac];

Swi = average total initial water saturation of oil-bearing rock [frac];

Boi = the average initial oil formation volume factor

[Reservoir barrels per stock tank barrel, rb/stb]; and

HPT = $h \cdot \phi \cdot (1 - S_{wi})$ = hydrocarbon pore-thickness [ft]

HPT is determined mainly based on petrophysical evaluation. But in the case of thin bed lamination HPT would be underestimated seriously by classic petrophysical evaluation.

As can be seen in Figure 1a, GR reading is rather high around 60 GAPI and resistivity is in the range of 2-3 Ohmm. Neutron density doesn't show any cross over hence a clean zone is not expected. The yellow colored interval is thin sand layers and green ones are shale thin layers. By applying normal cutoffs (GR < 50 GAPI, Rt > 3 Ohmm) after well log evaluation, the hydrocarbon thickness would be zero which is equivalent to non-reservoir interval. But the same interval, after been put on production, could produce water free oil. This is the definition of thin bed evaluation: due to the fact that thin beds are below the resolution of well logging tools, the true response of pay zone cannot be recorded and classical well log evaluation would result in "Under Estimation "of reservoir hydrocarbon thickness.

The aim of this study is to evaluate low resistivity pays properly such that true net to gross, porosity and saturation matches the real values.

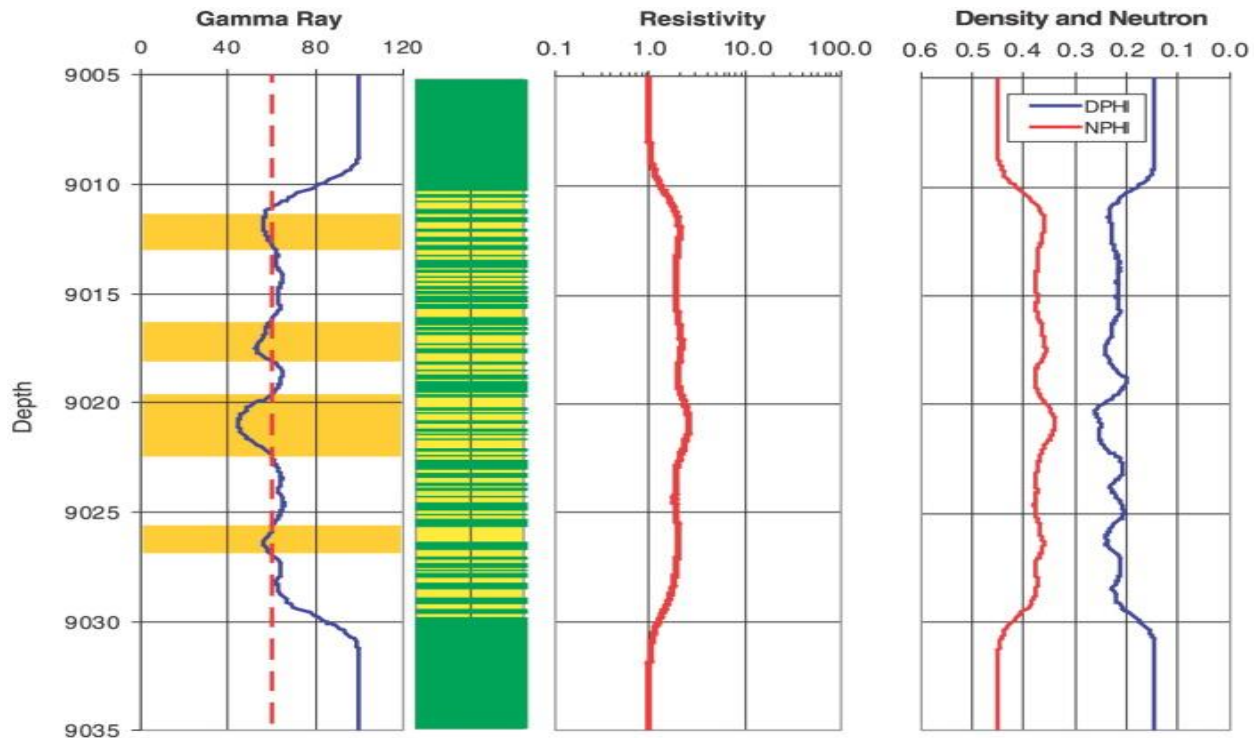


Figure 1a Typical Log Responses in Thin Bed Interval

As suggested by Figure 1b classical petrophysical evaluation underestimates HPT seriously. It is only acceptable only when net to gross is around 90% or more. Now, the problem of petrophysical evaluation in thin bed laminations is clearly defined.

New methods should be developed to overcome the problem. There has been long years of research on this area and different methods have been developed and applied on the subject. There is still much interest to propose new workflows by oil companies as well as service companies to accurately evaluate their assets. The proposed methods range from volumetric methods as Thomas-Stieber to new tool based methods as Laminated Shaly Sand Analysis (LSSA) – based on multi component resistivity, vertical resistivity – Nuclear Magnetic Resonance (NMR) based analysis, to more modern high resolution workflows as convolution, deconvolution, forward modeling, inversion, to low resolution workflows as Volumetric Laminated Sandy Shale (VLSA),

Monte Carlo analysis and analytic to semi analytic to numerical simulation methods as well, etc.

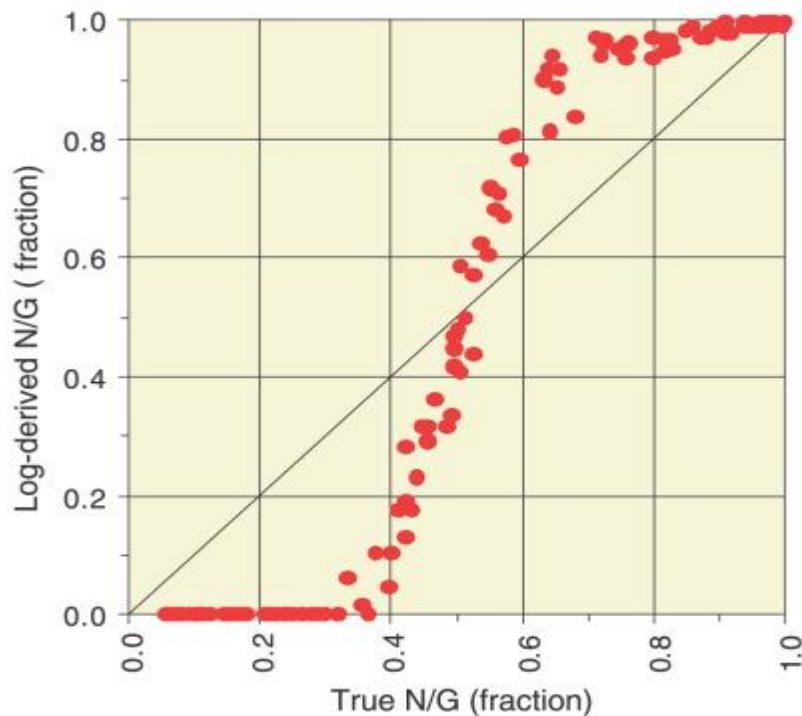


Figure 1b Comparison of actual and GR-derived net sand fraction (N/G)

Very well-known Thomas – Stieber method relies on defining pure shale and sand points as reference points. Then based on simple model, it tries to find theoretical complete dispersed clay point and theoretical complete structural shale point. Finally based on three point leverage rule will calculate the fraction of dispersed clay and laminated clay. The advantage of this method is simple assumptions and choosing reference pure sand and shale points based on which the rest of calculations would be done; simplicity in calculations. But this method is not a diagnostic method to determine whether the interval of interest is laminated shale sand or not; which means it can calculate laminated shale sand fraction but the interval is dispersed clay, shaly - sand interval in reality. This method is too much sensitive to reference pure clay and sand points.

LSSA proved to be a practical method which is based on the application of multicomponent resistivity – vertical resistivity – tools which is the most recent tools in the category of resistivity tools. LSSA solves two equations of resistivity in parallel and series simultaneously to derive true resistivity of sand. Some simplifying assumptions is involved LSSA which considers vertical and horizontal resistivity of shale and sand is the same which is not true necessarily and can be quite different in several order of magnitude for shale resistivity.

NMR based analysis focuses on detection of bimodal porosity distribution but it cannot clearly determine if the clay distribution is laminated or dispersed form. Meanwhile since the tool is short reading in nature, it will not be helpful for true calculation of saturation. NMR result can have general added value if combined with other tools like image logs in addition to fullset logs.

Low resolution methods (VLSA) are normally run based on statistical earth model that an average value is assigned to an interval. A priori knowledge of input data is necessary to describe all parameters as frequency histogram. Then Monte – Carlo algorithm would be coupled by mathematical log response model to cover the whole possible range of combined probability of input parameters which are log data and constants and hence to produce the frequency histogram of output parameter which is HPT. The mean HPT value derived from HPT frequency plot is considered to be the answer for the whole interval. Low resolution methods cannot produce a log at each depth increment. The main area of their applicability is where there are not enough accurate data to be build an explicit earth model; namely turbidites in which the thickness of layers are in the order of millimeters and number of layers are such numerous such that an accurate earth model cannot be developed for as well as any interval with limited input data.

Analytic methods is mathematical physical modeling of tool response based on the underlying physics, e.g. Electromagnetic Law of Maxwell for resistivity tools, nuclear physics for Neutron, Density and Gamma Ray logs, acoustic physics for sonic logs ,etc. Very well-known Doll geometrical factor theory is the primary model developed for resistivity logs which is valid at zero conductivity, so is not applicable for all real cases. Born response function was an improvement to Doll geometrical factor theory. These models are normally applicable for symmetrical cylindrical situation. Derivation of the models can be complex although ease of application would be a compensation. Any radial or axial unsymmetry caused by mud invasion, wash out, anisotropy, layering or dip make the model inapplicable for real case. Therefore, for practical cases the governing equations would be discretized in 2D or 3D dimensions and would be solved numerically. Finite element and finite difference were used with success for different cases. Due to complexity of nature of Maxwell equations, numerical solution of them is extremely time taking. Another issue is that the details of tool design are necessary to be known but manufacturing companies will not release the information for public use. For each tool design a new computer code should be developed.

In order to reduce simulation time, semi analytic methods depending on case, a combination of analytical and numerical methods applied successfully; which functions based on numerical solution of some equations and analytical solution of other equations. Meanwhile semi analytic method does not have general applicability of full 3D numerical method.

Modern evaluation methods with different names and techniques as convolution, deconvolution, inversion, resistivity modeling, forward modeling, made a milestone progress in evaluation of laminated shaly sand. An earth model with some initial assigned property – Resistivity, porosity, etc. – for each layer would be convolved by a convolution filter – Tool response function – to calculate a modeled log. Then modeled log would be

compared to recorded log by tool. The properties would be changed such that the modeled log matches best to recorded log. A good match confirms true property is achieved in earth model for each layer, which would be used for final interpretation. This is called iterative inversion. Other scholars tried to design the deconvolution filter for inversion in a direct manner; iterative inversion is accepted widely by industry in comparison to direct inversion.

A drawback for these methods is non uniqueness of the solutions which means there can be several different earth models by which modeled and recorded logs would match. In order to mitigate this problem, integration of other geoscience data is necessary. In the previously published researches, the layer thickness and top in earth model were just guessed from fullset log data, which cannot be considered satisfactory due to the fact that the thickness of layers of interest fall below tool resolution, so they need confirmation from other high resolution data as image log or core photo which were never mentioned in previous researches. In other word a good match is necessary but not sufficient and sufficiency is achievable only through third party data e.g. core, advanced log, test etc. This widely observed defect can be because of either lack of data or lack of knowledge of the researches; as the scientific background of the majority of involved researchers have been physics, electrical engineering for signal processing, mathematic, computer programmer , etc.

A very important power point of this research is integration of fullset, RCAL, SCAL, core photo and test results which have not been reported in any of previous published papers. Therefore validity of earth model is confirmed by core photo to avoid non- uniqueness problem. Besides, the optimization procedure of genetic algorithm was applied for automation of iterative inversion for the first time in this research domain which serves as the novelty of this research thesis. Genetic algorithm is a mathematical optimization algorithm inspired by natural evolutionary selection principles. It is widely applied in

different optimization processes and proved to be a successful tool for various engineering areas.

The industrial achievement can be concluded as an increase in HPT and OOIP as well as new recommended perforation interval.

It is shown that based on classical Petrophysical approach, hydrocarbon pore thickness is underestimated. Integration of core was an improvement. Earth model defined based on core photo; the thickness and depth of each thin layer was determined based on core photo. But finally based on forward modeling which is the main subject of this thesis the maximum hydrocarbon thickness was derived. This is because core saturations were not consistent. In reality only 3 meter was perforated before production. The result of current research showed the top most 1st meter from top of reservoir which was the most prolific interval was not perforated. It is recommended based on the results that it should be perforated. Although presence of oil is proved by well test results but this is cannot eliminate the need for accurate determination of HPT; needless to say it is not achievable through classic Petrophysics.

A computer code developed in this research to perform the mentioned simulation by using MATLAB coding language. This is because these codes are not available in any of the commercial softwares. The applied method in this thesis is called “SHARP PROCESSING” by Schlumberger and is charged several thousand euro per meter analysis.

Thin Beds and Tool Resolution

Definition: Vertical resolution

As discussed before the vertical resolution of a logging tool is defined as the thickness of the thinnest bed in which a true reading can be obtained.

Vertical resolution and bed thickness

Figure 9 shows a comparison of bed thickness and typical resolution of logging tools, core plugs, and thin sections. [Campbell, 1967]

Definition: Detection limit

Loosely defined, the detection limit of a logging tool is the thickness below which a bed cannot be distinguished from its neighboring shoulder beds. This limit is not a fixed property of the logging tool, but also depends on the contrast between the bed and its neighbors. Most thin-bedded reservoirs contain beds that are below the detection limits of conventional logs. In particular, very thin beds are usually below the detection limits of all the logs used in conventional formation evaluation. This is the factor that can render difficult, or even impossible, the unambiguous identification of a thin-bedded reservoir based on standard logs alone.

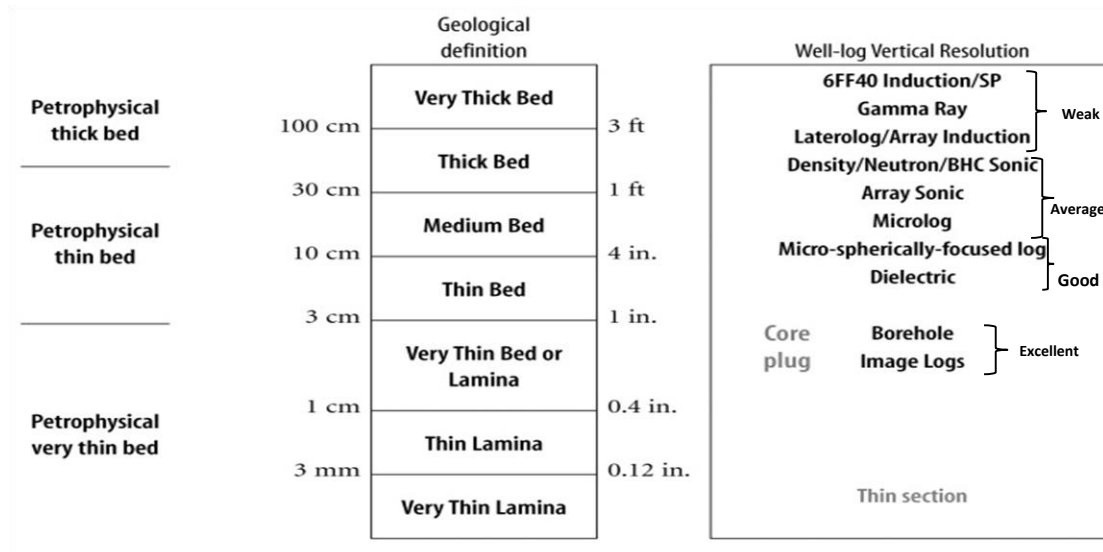


Figure 2 Comparison of petrophysical beds, geological beds [after Campbell, 1967], and well-log vertical resolution

Are Thin Beds Present?

Direct indicators of thin beds include:

- Sidewall cores
- Conventional core and core images
- Indirect indicators of the presence of thin beds include:
 - Borehole image logs (electrical and acoustic)
 - NMR logs
 - Multi-component resistivity logs
 - Dipmeter logs
 - Conventional and high-resolution logs
 - Mud logs and drilling data

In addition, production-related data may give further indirect evidence of the presence of thin bedding:

- Wireline formation tests

Each of these indicators is discussed below.

Direct Indicators of Thin Beds

Conventional core and core images

For establishing thin-bed ground-truth in an interval, there is no substitute for conventional core. Moreover, digital core images can provide a convenient means of comparing core to log response, and determining the volumes of sand and shale with a high confidence

level. **Figure 10** shows a 20-ft [6-m] slabbed core interval depth-aligned to an electrical borehole image log (EBI*).

Both the white- and ultraviolet-light core images can be used to differentiate oil-bearing sandstone (light) from shale (dark) layers. In the example in **Figure 10**, laminations as thin as a few millimeters are readily discernible.

* Note: We use a non-standard name and acronym (electrical borehole image, EBI) to refer generically to anyone of a collection of micro-electrical borehole imaging tools.

[Passey et al. 2006]

Indirect Indicators of Thin Beds

Borehole images

Digital electrical and acoustic borehole images provide unique log data that is, in many respects, similar to conventional core images. Like core images, they provide a high-resolution view of the formation that allows high-resolution geological and petrophysical interpretations. Assuming high-quality data, accurate calibration, and proper processing, the high-resolution images can provide: [Sovich, J. P., and B. Newberry]

- Identification of thin-bed occurrence;
- Quantification of bed thickness;
- Interpretation of gross sandstone thickness;
- Identification of descriptive rock facies; and
- In some cases, interpretation of hydrocarbon-bearing sandstone thickness.

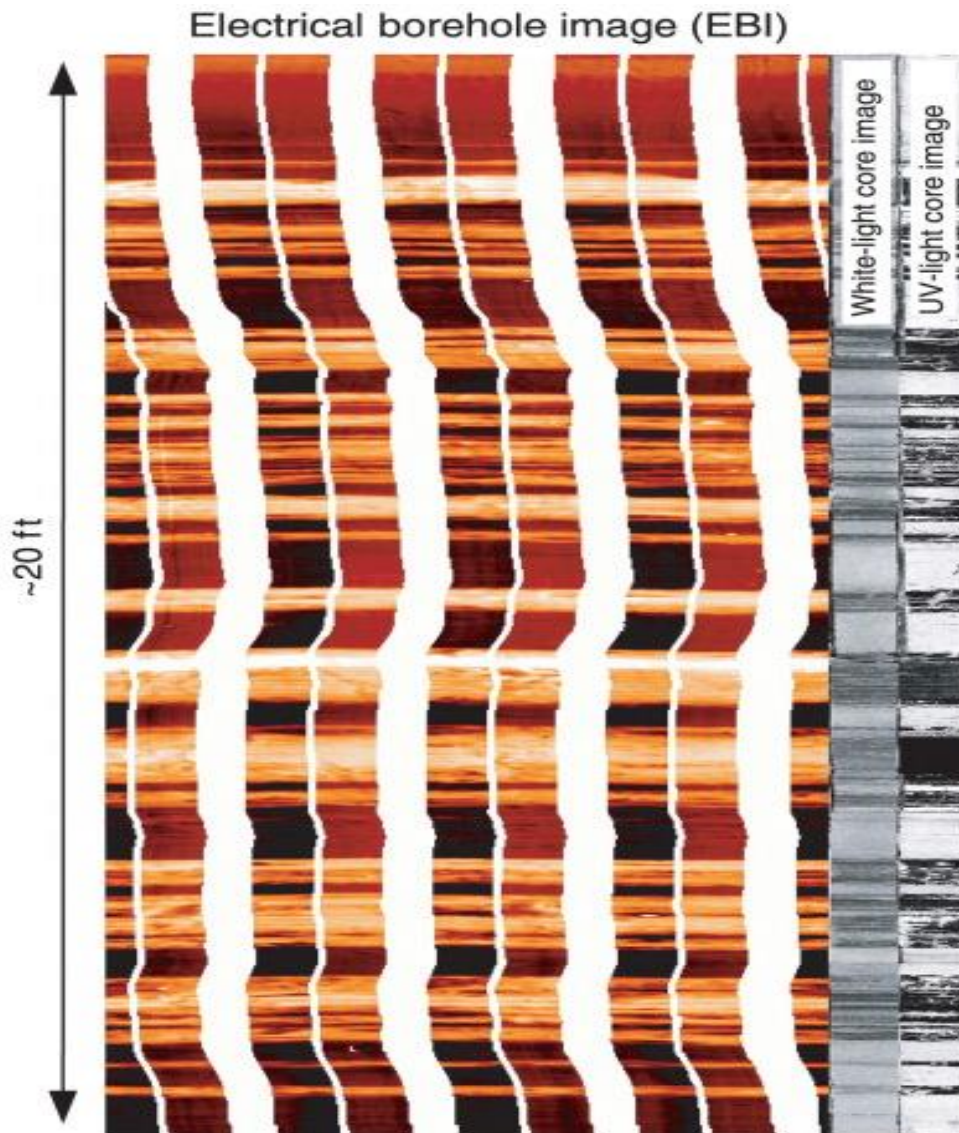


Figure 3 Borehole image log (left) correlated with core images (right). [Serra 2004]

In Figure 10, the high-quality electrical borehole image (EBI) data detect beds as thin as 2 cm [.8 in.] or less. Note that the shale beds, which appear dark in the core images, are bright (or more resistive) in the EBI image even though the sandstones are hydrocarbon bearing. [Sovich, J. P., and B. Newberry]

At first inspection, the upper part of the EBI image in Figure 11 might be interpreted as containing thinly interbedded shales (dark) and sandstones (bright). Closer inspection indicates a strong correlation between the caliper and the dark intervals, suggesting that the EBI is reading mostly drilling mud in the washouts. [Serra, O., 1989]

Although the presence of thin beds may be inferred from borehole images, it is often impossible to interpret lithology from these images alone.

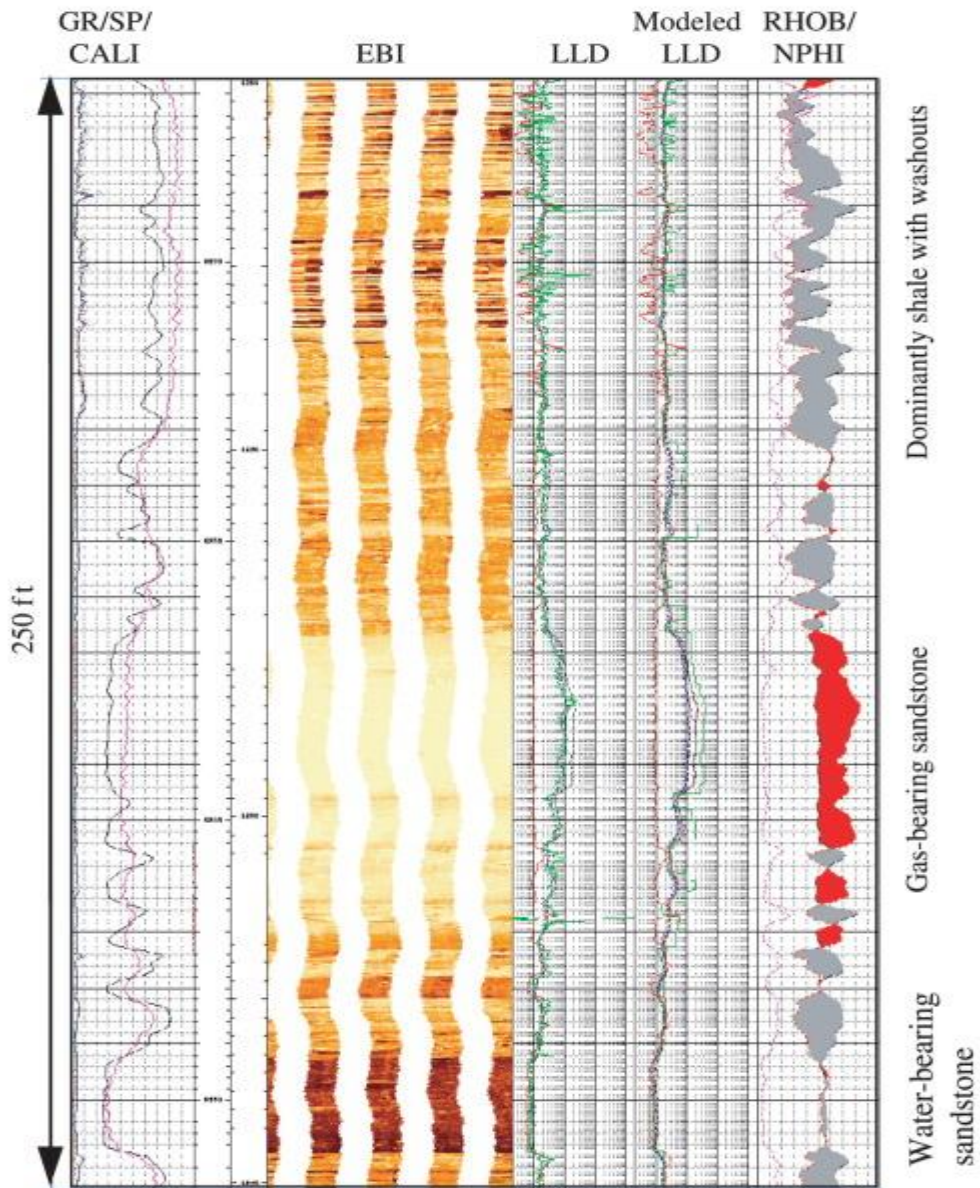


Figure 4 Integrated borehole image and log interpretation for a deep-water turbidite reservoir. [Serra 2004]

Dipmeter logs

The vertical resolution of standard dipmeter logs is similar to that of electrical borehole- [Serra and Andreani, 1991]

In the example in Figure 12, a 6-m [19.7-ft] section of interpreted dipmeter data is shown. Note that it is reasonable to infer from these data that this interval is characterized by thin, parallel beds. [Serra and Andreani, 1991]

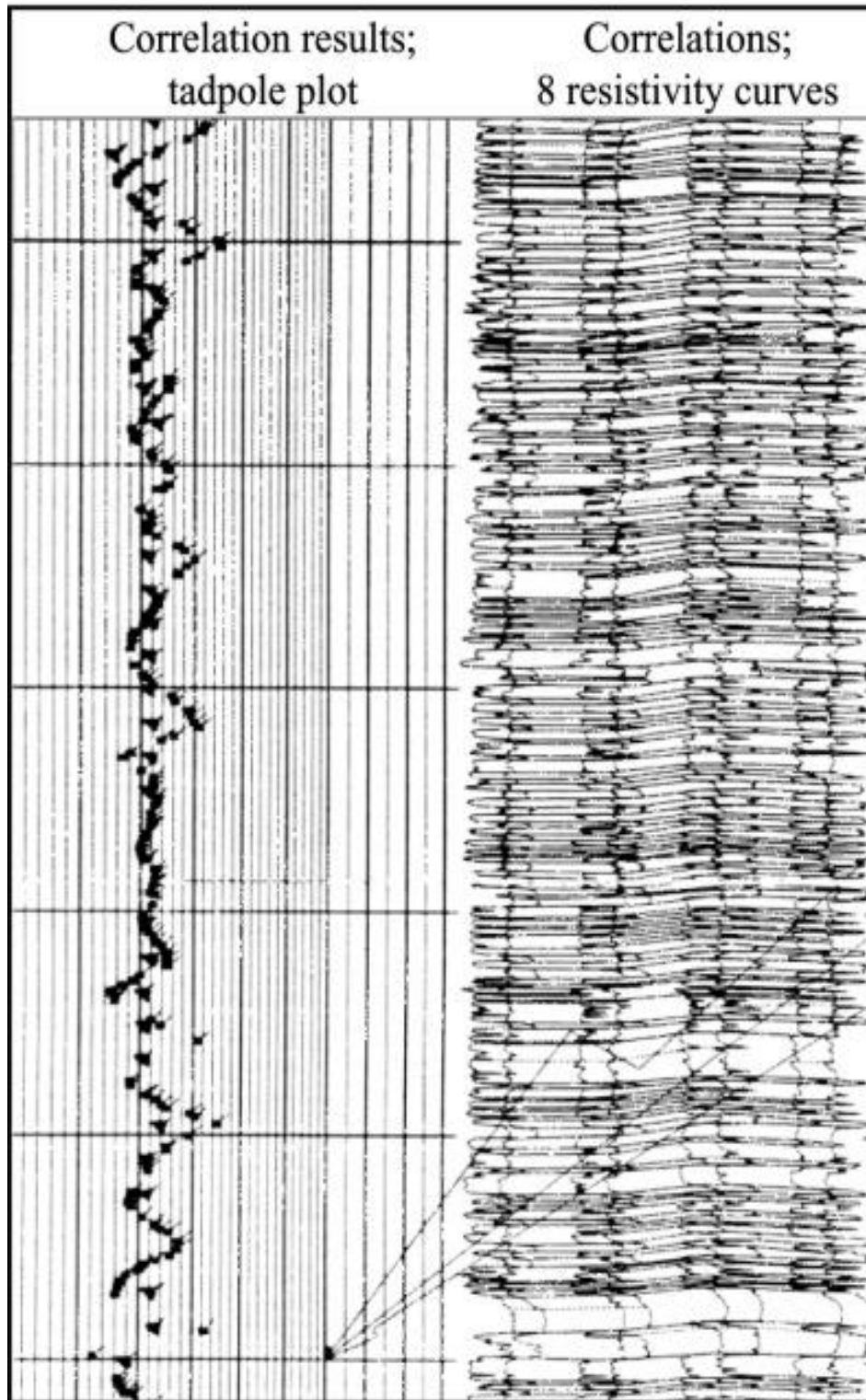


Figure 5 Dipmeter plot (1 m [3.3 ft] per division). Correlated high-frequency features on resistivity curves suggest thin parallel beds [Serra and Andreani, 1991].

Conventional and High-Resolution Logs

Following is a list of several methods used to infer the presence of thin beds from standard and high-resolution log data [modified after Serra and Andreani, 1991]:

- Spontaneous potential (SP) and gamma ray (GR) indicate a shaly formation, often with high-frequency variations.
- Porosity logs exhibit high-frequency variations, and the density curve may mirror the neutron curve. Density and neutron are closer together compared to a massive shale. In some interbedded formations, the density curve will show variation when the neutron curve is relatively constant.
- If the thin sands are hydrocarbon-bearing, the resistivity curve is slightly elevated relative to surrounding shales.
- Spherically focused log (SFL) appears spiky, indicating that thin beds of high resistivity are not resolved by the deeper-reading induction tool.
- Increased separation between shallow and deep resistivity measurements relative to shales, indicating that permeable intervals are present.
- High-frequency amplitude variation on shallow resistivity and/or dielectric log(s), especially on the dielectric attenuation curve.
- Microlog separation indicating thin permeable beds.
- Caliper less than bit size, indicating mudcake in permeable zones. [Serra and Andreani, 1991]

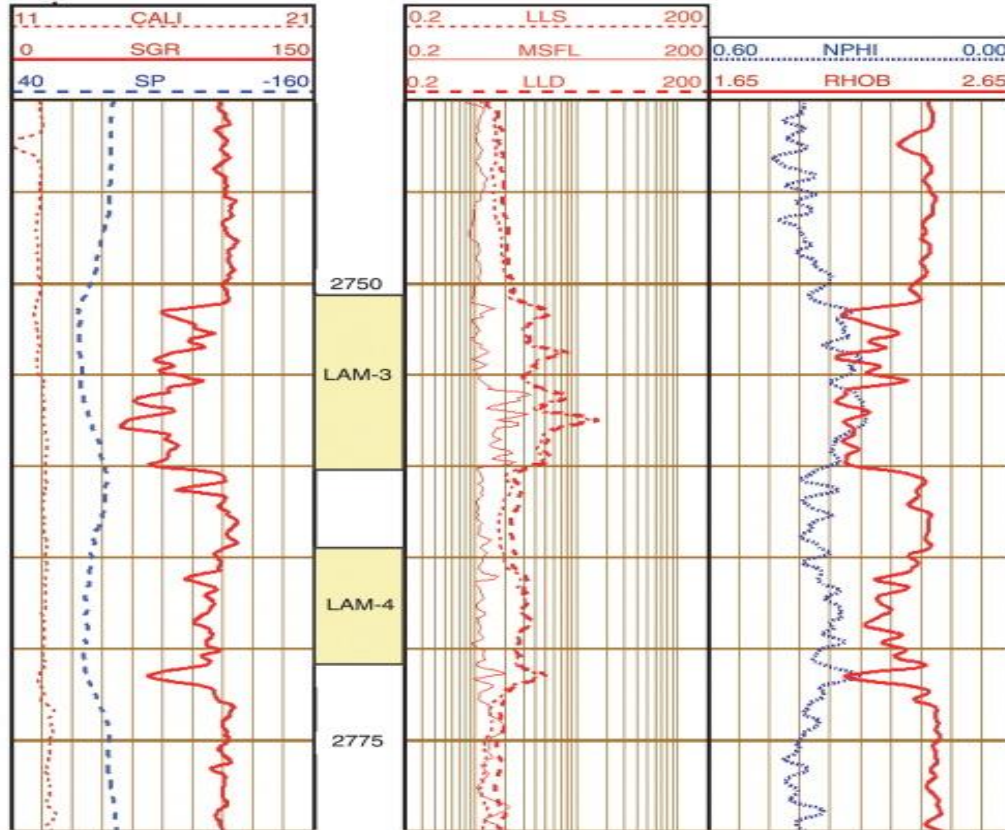


Figure 6 Conventional well-log response to laminated sandstone and shale intervals

Figure 13 illustrates several of these points with standard well logs for two laminated sandstone intervals. For the upper laminated sand (LAM-3), both the SP and gamma-ray curves indicate the presence of sandstone, but the gamma-ray curve never measures the low GAPI values expected for clean sandstones. These observations, and the high frequency of the SGR curve, suggest that thin shale interbeds are present in this interval. The neutron/density curves indicate interbedded sandstones and shales, with the two curves mirroring each other. The shallow resistivity curve (MSFL) suggests thin hydrocarbon-bearing beds, with the overall resistivity response higher than surrounding thick shales. [Serra and Andreani, 1991]

For the laminated sand LAM-4, the SP indicates a sandy interval, but the gamma-ray curve gives some indication of thin sandstones interbedded in a primarily shale interval. Overall, the gamma-ray response is slightly lower than in the underlying shale (below 2773 m [9098 ft]). As with LAM-3, the neutron and density curves mirror each other, but the separation indicates a shalier interval than LAM-3. Also, the deep resistivity curve is slightly higher than in the surrounding thick shales, suggesting the presence of thin, hydrocarbon-bearing sandstones. [Serra and Andreani, 1991]

NMR logs

The NMR T_2 distribution [Ye and Rabiller, 2000] may often be used to infer the presence of a thinly bedded reservoir where conventional logs apparently see only shale. Figure 14 shows such an example. The data is from an offshore deep water turbidite deposit that was fully cored.

With this information, one can readily identify the thick reservoir sands below 2657 m [8718 ft]. But what is happening at depths shallower than 2657 m [8718 ft]? [Ye and Rabiller, 2000]

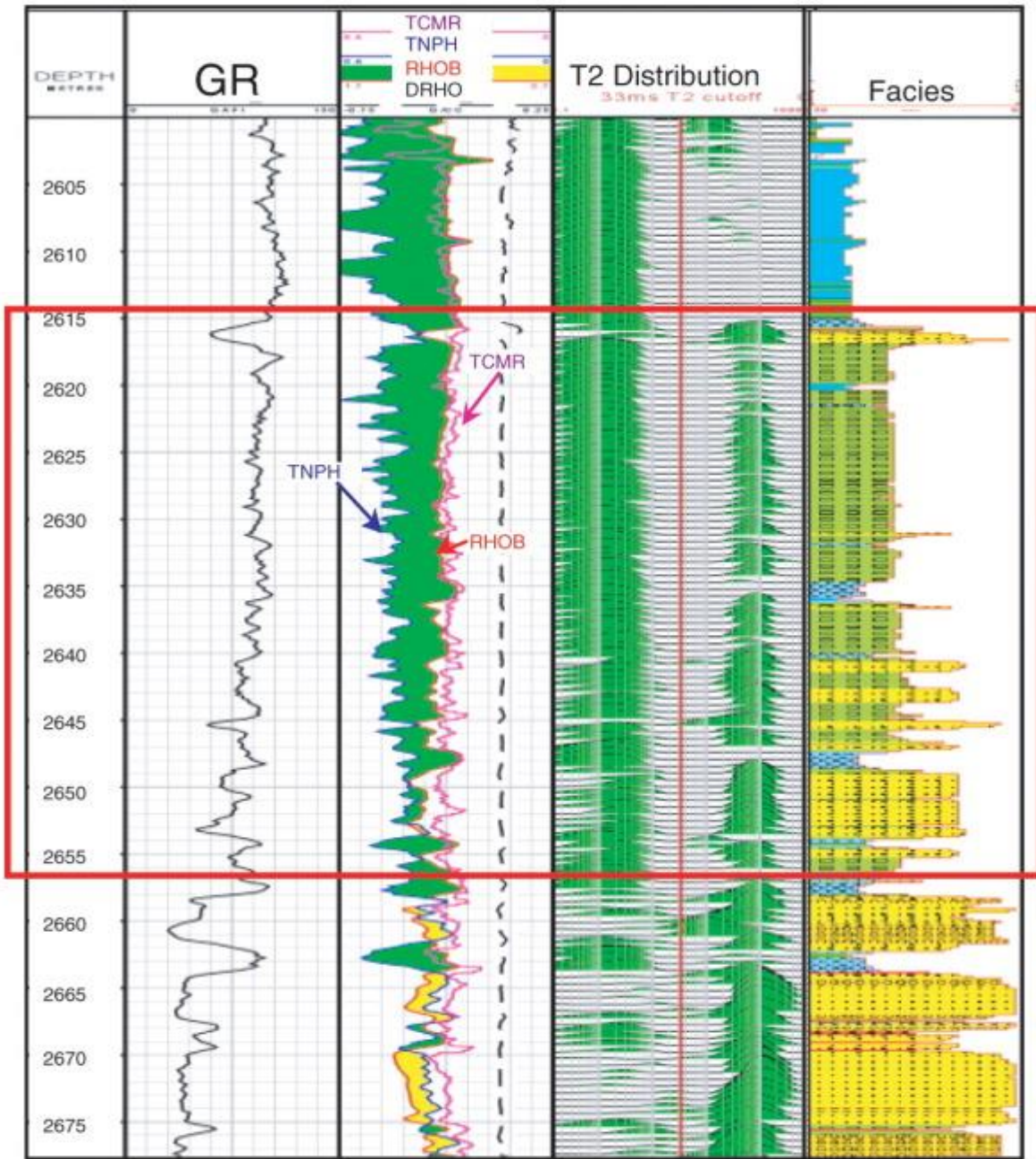


Figure 7 NMR T2 distribution (Track 3) shows the presence of thinly interbedded sands and shales in the interval between 2615 and 2657 m [8580 and 8718 ft] (red box) [Ye and Rabiller, 2000].

The only likely interpretation is that between 2615 and 2657 m [8580 and 8718 ft] the formation consists of thin sands interbedded with shales. Shallower than 2615 m [8580 ft], there is only a thick shale.. Track 4 (a facies display) is included to confirm the information derived from NMR. [Ye and Rabiller, 2000]

Multi-component induction logs

The multi-component induction logging tool can provide a strong indication for the presence of thinly bedded reservoirs. In the simplest scenario, where the borehole penetrates perpendicular to the horizontal bedding planes and the individual sand and shale beds are planar and isotropic, such a tool will measure two resistivities. First is the horizontal resistivity (R_h), which is measured by currents parallel to the bedding planes and is equivalent to the standard induction-log resistivity.

Second is the vertical resistivity (R_v), which is measured by currents transverse to the bedding planes. R_h is extremely sensitive to the low-resistivity interbedded shales, while R_v is much more sensitive to the high-resistivity hydrocarbon-bearing sands. [Gianzero et al., 2002]

Figure 15 is a synthetic log illustrating R_h and R_v in a case where the sand fraction is only 30%. The gamma ray, density and neutron porosities, and R_h barely hint at the presence of hydrocarbon sand in the interval from 9010 to 9030 ft [2746 to 2752 m], while the R_v measurement responds strongly to the resistive sand. [Gianzero et al., 2002]

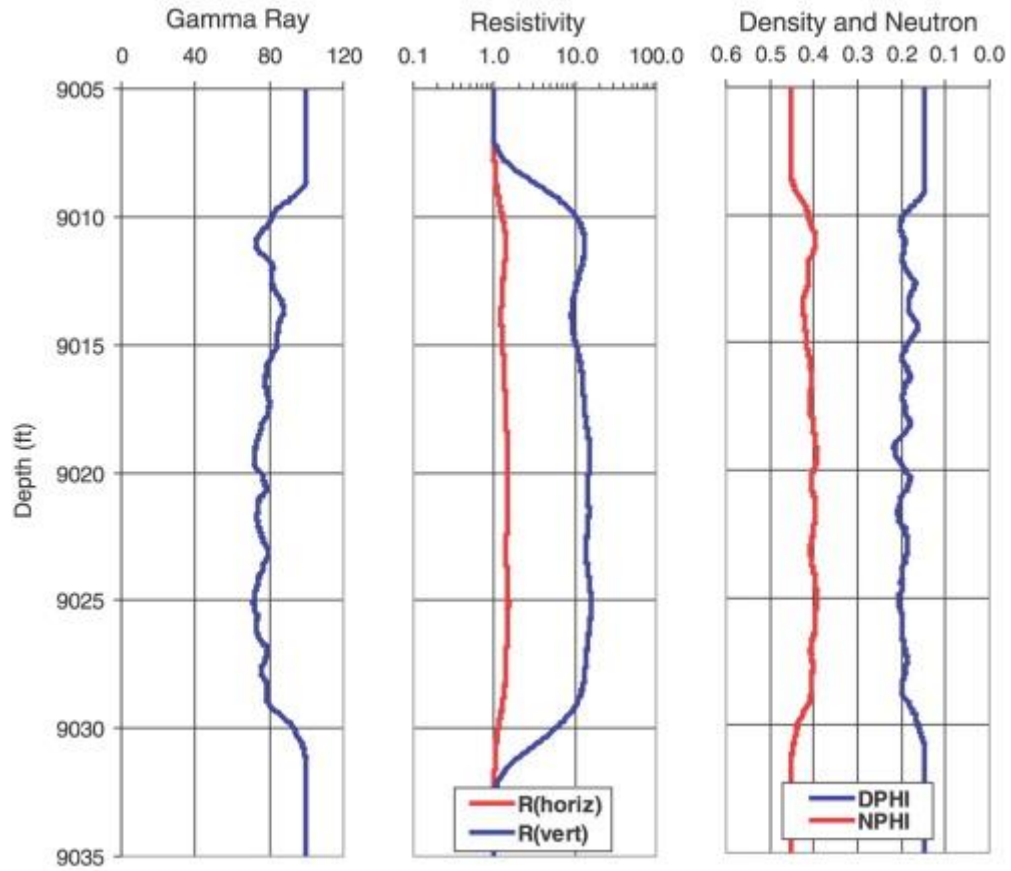


Figure 8 Synthetic triaxial resistivity measurements in a thinly bedded formation with $V_{sh} = 70\%$.

Forward and Inverse Modeling

Forward Modeling

The process of calculating a well-log response numerically for a given earth model is referred to as forward modeling. An algorithm or computer code for performing such a calculation is a forward model. Each forward model is closely linked to a specific type of earth model, since it is the earth model that carries all the data required as input for the forward model's calculations. Forward models typically produce a unique solution at each depth of the earth model, so they may also be called tool response functions.

Figure 22 is a schematic illustration of 1-D forward models of shallow, medium, and deep resistivity logs. The geometry of the earth model is shown on the left. The resistivity of the earth model's beds is shown on the right as the orange line and shading, labeled RT. The forward models assume no borehole or invasion effects. These forward models, which are 1-D convolution filters, are shown graphically in the middle. Overlaid on the RT curve on the right-hand side are the shallow (blue), medium (green), and deep (red) resistivity logs calculated by the respective forward models. Several types of forward model useful in thin-bed evaluation are described below. [Passey et al. 2006]

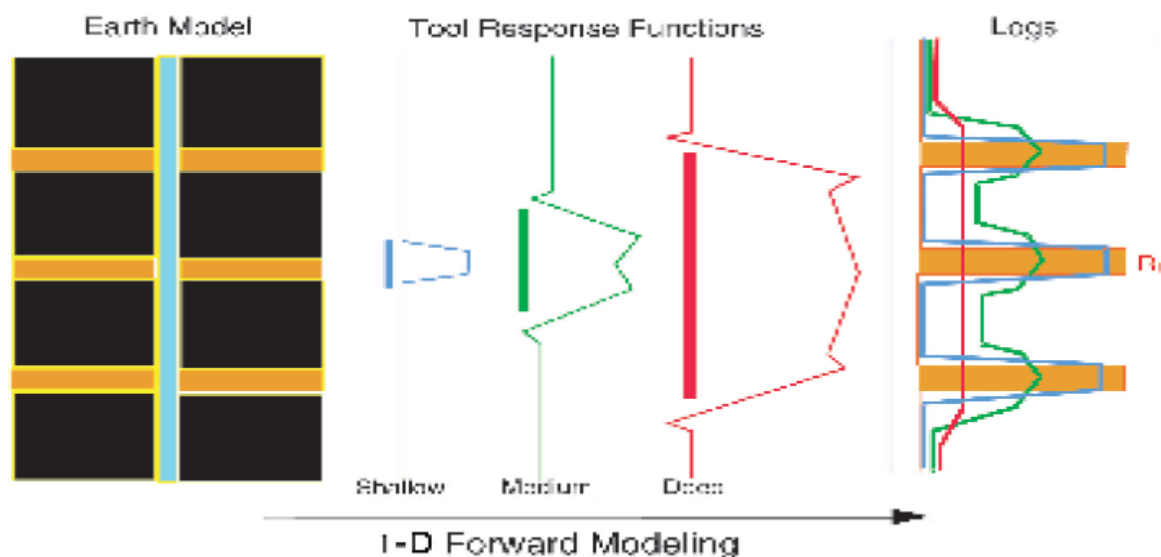


Figure 9 Schematic representation of 1-D forward modeling.

Inverse Modeling

When we log a well, what we hope to obtain from the well logs is an accurate earth model of the logged formations, including both the bedding geometry and the petrophysical properties of the beds. The logs themselves are only indirect indicators of this true earth model because their measurements are affected by bed thickness, shoulder beds, borehole conditions, invasion, and other factors. Therefore the estimation of the earth model from the logs requires a process of inference.

This process of deriving the geometric and petrophysical parameters of an earth model from a set of given field logs and the appropriate tool-response functions are referred to as inverse modeling or simply inversion. Figure 23 illustrates inversion of a deep resistivity log using an iterative procedure based on the 1-D tool response function shown in Figure 22. In Figure 23, the earth-model geometry (horizontal planar beds) is shown on the left. In the center, the log at A shows an initial guess for the true resistivities of the earth model as the squared orange curve. The measured field log is shown in blue, and the calculated log based on the earth model and the tool response function is shown in red. Mismatches between the field log and the modeled log are evident. In the inversion step, the resistivity values of the earth model's beds are adjusted iteratively to optimize the match between the field log and the modeled log.

The log at B shows the final inversion result. The revised earth-model resistivities are again shown as the squared orange curve. The calculated log (red) hides the field log (blue), showing that a good replication of the measured data was obtained. The final earth model (with its beds and resistivities) is then taken to be a better representation of the actual distribution of R_t — true formation resistivity — than the original measured log. In the example of Figure 23, the iterative inversion procedure adjusted the earth-model resistivities and left the bed boundaries fixed. This procedure might be employed in a case where bed boundaries can be defined with confidence using high-resolution data such as a borehole image log. In general, however, all parameters of the earth model,

including the number of beds and the locations of their boundaries, can be adjusted to optimize the fit between the modeled and measured logs. [Passey et al. 2006]. Several methods of inverse modeling that have been employed in thin-bed evaluation are discussed below.

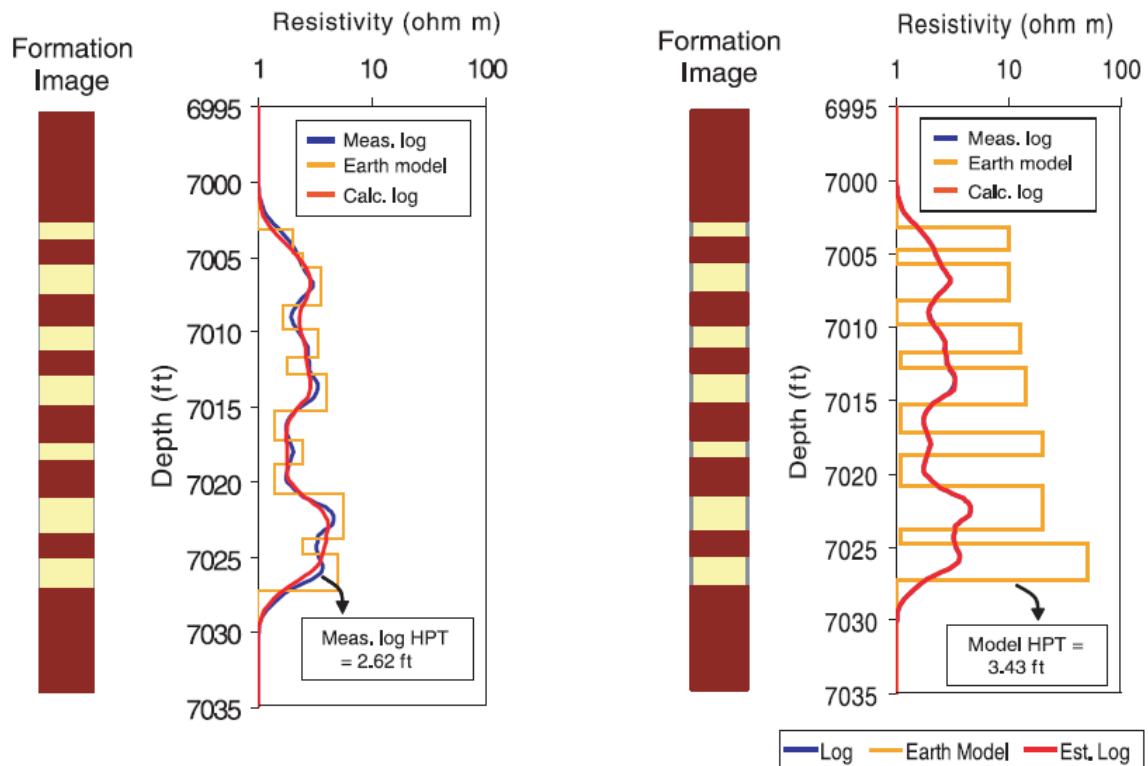


Figure 10 Schematic illustration of inverse modeling [modified from Passey et al., 2004].

1-D Convolution Models

Figure 24 illustrates a 1-D convolution model for a gamma ray (GR) log. The earth model (a 10-ft [3-m] subinterval of a longer interval) is subdivided into layers of equal thickness. The earth model is shown on the left and its subdivision into 10 layers per ft is indicated by the tick marks on the left vertical axis. Petrophysical beds, indicated by colored bars, are composed of one or more contiguous layers. The orange beds have GR = 20 and the

green beds have GR = 100, as indicated on the horizontal axis. The set of GR values situated at the center of each layer form a data series, {GR_i, 1 ≤ i ≤ 100}.

The convolution model is defined by a convolution filter representing the logging tool's impulse response function — that is, its vertical response to an infinitesimally thin bed. The convolution filter quantifies how the finite-length logging tool “smears” the measurement of a very thin bed.[Anderson 2001]

Mathematically the convolution filter is expressed as a set of constant numeric coefficients, {f_i, -N ≤ i ≤ N}, which are normalized so their sum is one (1). The index (i) represents the same depth increment as the layer thickness in the subdivided earth model. In Figure 24 the convolution filter is plotted in the center with its indices along the vertical axis. Its non-zero coefficients extend from about i = -20 to i = 20.

The modeled log, GR (mod), is computed by convolving the earth-model data series with the tool filter coefficients as in Equation 2.[Anderson 2001]

$$GR(mod)_k = \sum_{i=-N}^N f_i \cdot GR_{k-i} \quad \text{Eq. 2}$$

For this example, depth is related to the index (k) in Equation 2 by

$$\text{depth} = XX00 + (k - 1)/10 \text{ where } 1 \leq k \leq 100 \quad \text{Eq. 3}$$

The blue dot on the modeled GR log (right side of Figure 24) represents GR (mod) 51, located at depth XX05 feet. The other modeled points are plotted as a continuous blue curve.

Convolution models can be developed for all the most commonly-used conventional logs [Looyestijn, 1982]. In general, logging tools are designed so that their response characteristics are as close as possible to linear for the simple earth geometry illustrated in Figure 24. Linearity in this context means precisely that the tool's vertical response can be approximated adequately by a 1-D convolution model.[Looyestijn,1982]

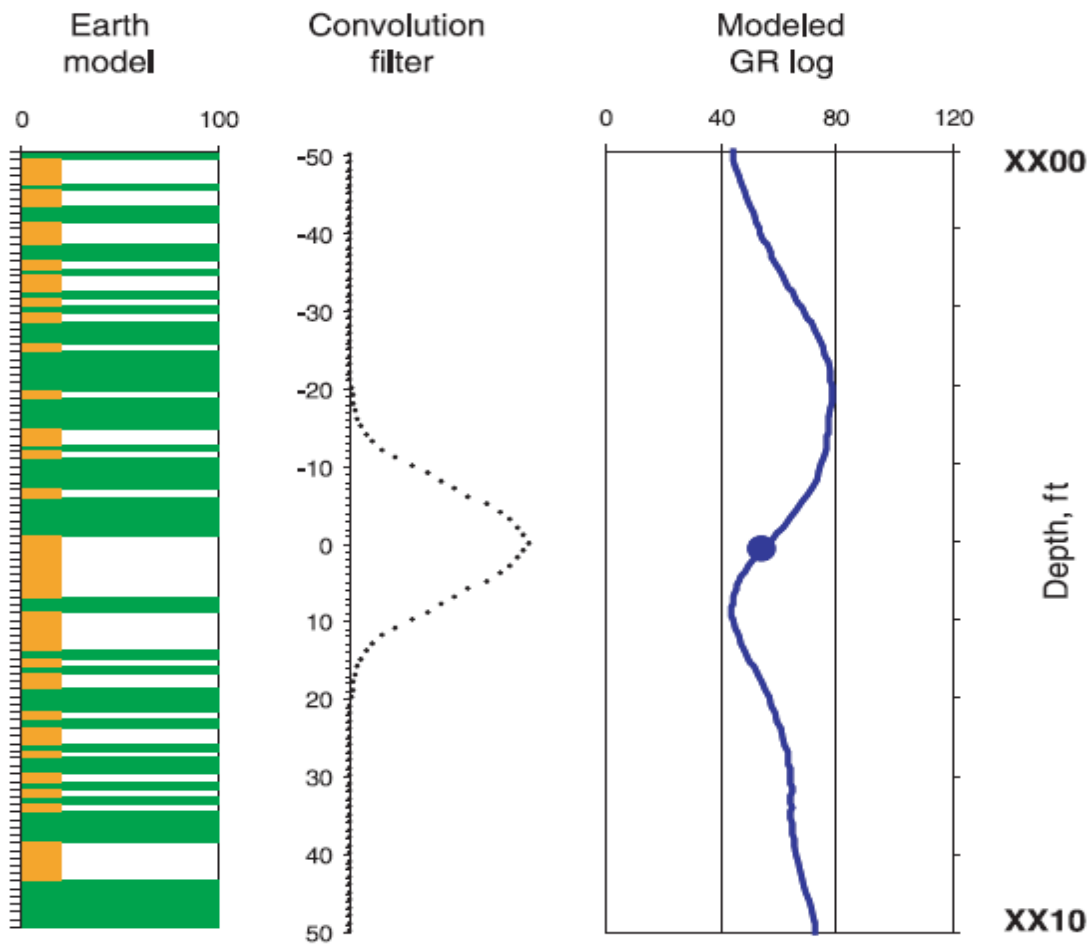


Figure 11 The components of a 1-D convolution model for a GR log. [Passey et al. 2004]

Analysis and Modeling

The field is located in Romania and the field name and formation would not be mentioned as requested by field owner. We will consider it as field “A” in this thesis. Field A is a thin layered thin bed sand lamination with around 5 m gross thickness. It is mainly comprised of sand and shale in lamination distribution format with limited amount of calcitic cement. Permeability is quite high for loose sand parts and low in clay bearing interval.

Available Data

Fullset log as well as core data are available. Details of data are tabulated below.

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Table 1 Available Core and Log Data

Log Data		Core Data	
Log Name	Interval (m)	Core Parameter	Interval (m)
Caliper	10	Porosity	9
Density	10	Permeability	9
Neutron	10	Grain Density	9
Gamma Ray	10	Oil Saturation	9
Sonic	10	Water Saturation	9
Photo Electric	10	Description	9
Deep Resistivity	10	Photo	9
Short Resistivity	10		

Well Log Data

General quality of logs is good since in the cored interval there are no washouts, which can be investigated in the below figure.

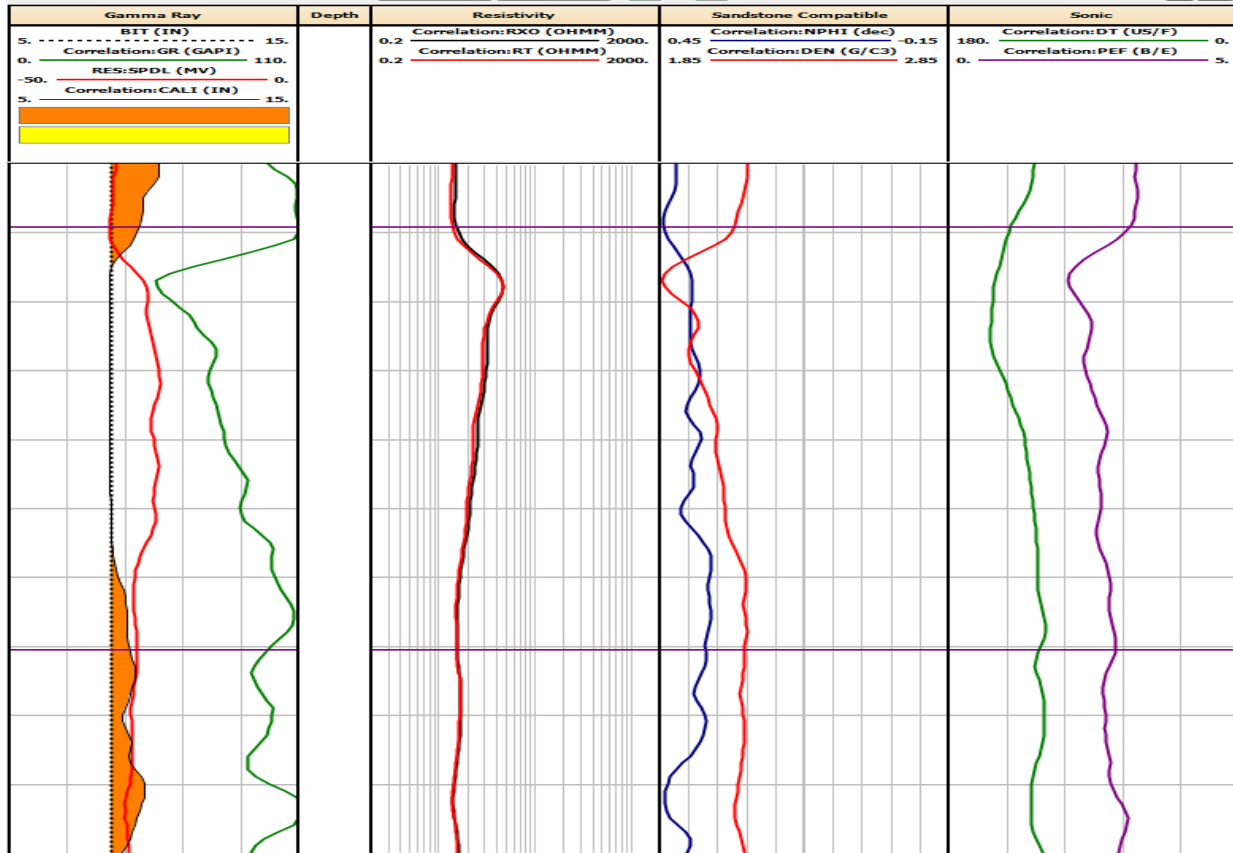


Figure 12 Raw Well Log

Gamma Ray is generally high; it reads minimum 60 GAPI which is not promising to have a prolific reservoir. Resistivity curves are overlying which is not indication of permeable interval. Due to having higher resolution, Neutron-Density logs show a very small clean interval (< 0.5 m). Sonic log reads very high (>140 microsec /ft) close to shale. The standard petrophysical evaluation result is shown below.

Very small oil column in the order of maximum 1 meter can be observed. General conclusion is that the reservoir is not prolific up to this point. The well was perforated and produced mainly oil after being tested. What is the correct saturation? How much is true oil column? Therefore we need to update the formation evaluation based on integrating with other data. The first candidate is core data.

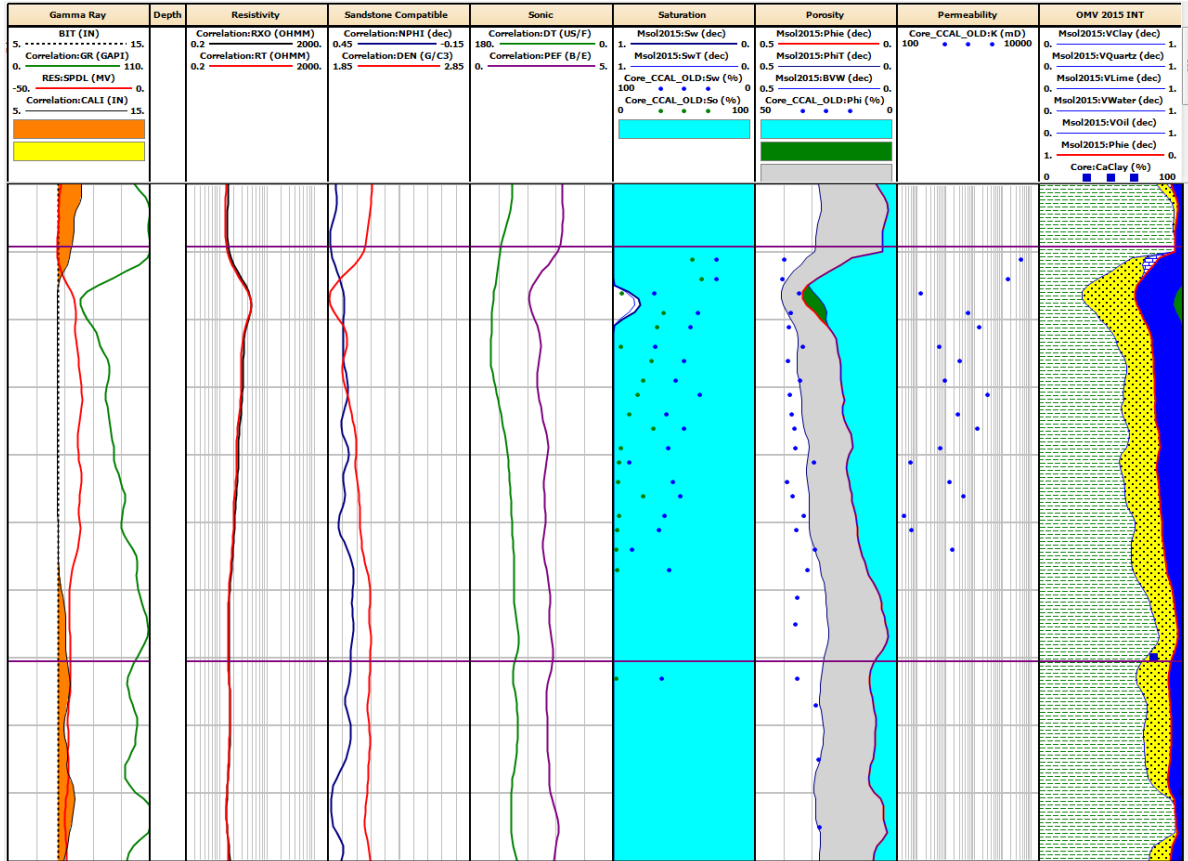


Figure 13 Standard Petrophysical Evaluation

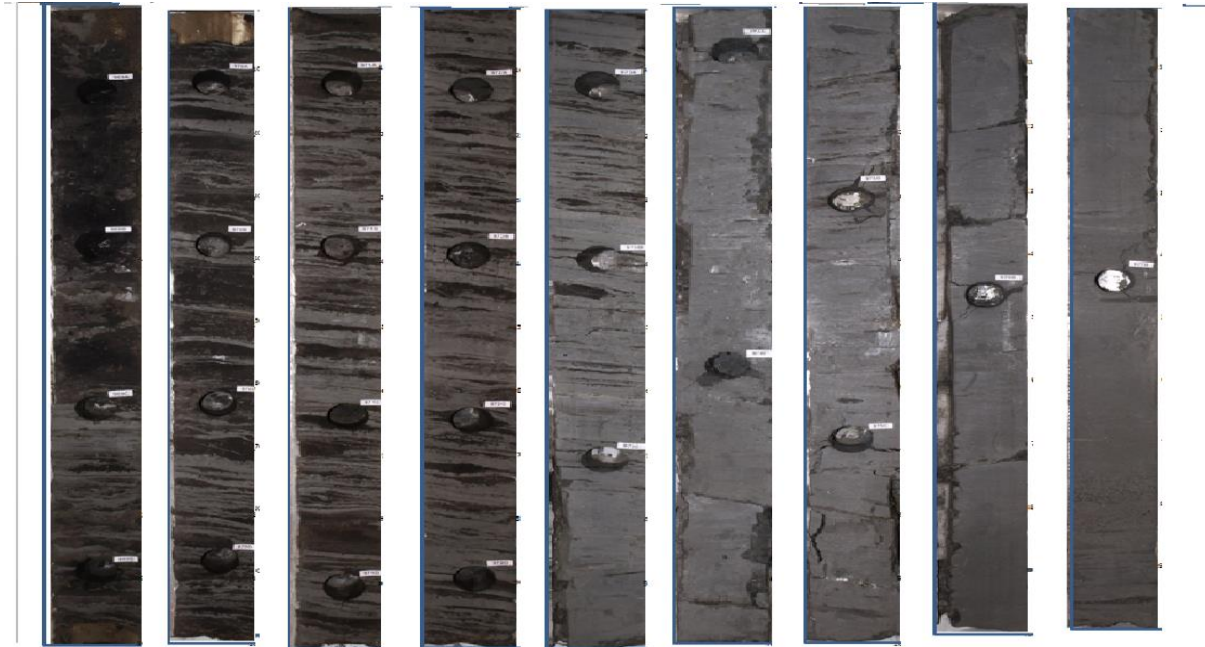


Figure 14 Core Photo of Field A

Core photos in the above figure confirm presence of sand shale thin layers. Each column is a 1m barrel of core. Depth increases from left to right which means the left most picture is reservoir top. The first four meters of the core shows oil stain. Oil stain decreases as it goes deeper. The bottom five meters is almost shale. There is a large contrast in permeability data which confirms alternation of thin layer shale and sand. Another important observation is core saturations. Summation of water and oil saturation is not 100%. Error in core saturation is expected when core is not taken under preserved condition. Gas content of oil would be vaporized and oil volume would shrink. Parts of water can also be vaporized into air to reduce original water volume. If water based mud is used during coring, mud filtrate would replace parts of original oil to decrease oil saturation from original saturation. If oil based mud is used during coring, mud filtrate would replace parts of original water to increase oil saturation. These are some challenges involved in core saturation determination.

By reviewing core saturations, it suggests that the well should produce water mainly, but in reality it has produced oil. It can be concluded although core data are highly valuable regarding porosity and permeability, but core saturations can be quite misleading. In this sense formation evaluation in thin laminated cannot be done only based on core data.

What is the correct saturation? How much is true oil column? These questions are not answered yet.

High Resolution Formation Evaluation in Laminated Shale Sand Reservoir

Earth Model

The need to other sources of formation evaluation is clear now based on previous review of data. Details of High Resolution Formation evaluation was mentioned in chapter 2. At the first step we need to create an explicit earth model. The main constituents are layer thickness and initial guess for Rt in each layer.

Explicit earth model was created based on core photo to define thin layer thickness. An example is shown below. The interval with similar color is considered to have same property hence considered as layer.

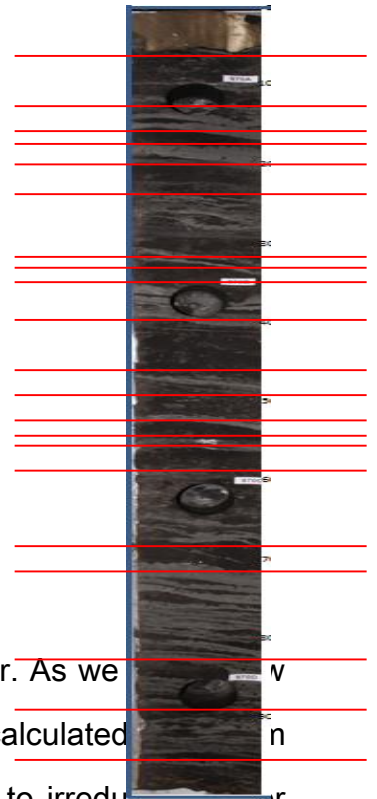


Figure 15 Defining Layer Thickness for Earth Model

The next step would be estimation of initial Rt in each defined layer. As we do not know exactly how much is water saturation for each layer, two Rt values calculated in each layer. One Rt value, based on minimum water saturation which is equivalent to irreducible water saturation (Swirr) and a minimum Rt value based on a maximum water saturation (Sw = 100 %).

The workflow is as follows; at first we need an estimation of Swirr which can be calculated by rearranging Timur correlation for Swirr.

$$K = a \phi^b / Swirr^c$$

Where

K = Permeability (md)

S_{wirr} = Irreducible Water Saturation (v/v)

Φ = Porosity (v/v)

$a = 8581$, $b = 4.4$, $c = 2$

By rearranging Timur formula S_{wirr} will be estimated. Now this value of S_{wirr} will be inserted in Archie formula to solve it for R_t . Based on this workflow a maximum R_t values were calculated.

On the other hand, in order to calculate minimum R_t , water saturation will be considered 100 % and by solving Archie formula for R_t , a minimum value for R_t will be calculated. The real R_t lies within this range. Therefore Maximum R_t and Minimum R_t will be used as check point for the calculated final R_t by high resolution formation evaluation method (Forward Modeling and Inversion).

Now earth model have a value of thickness and R_t for each layer. This earth model was imported in MATLAB programing software as input parameters.

Results

As a first step in improvement of results, petrophysical analysis is done again by considering core data. The result is shown in the following figure. The amount of sand and HPT increased considerably. As can be seen petrophysical analysis cannot show presence of thin layers as their thickness is less than log resolution. Based on real data, the well has not perforated in top most 1st meter, mainly due to the fact that resistivity curve reads low under effect of adjacent shale and water saturation is calculated to be high. This is the limitation of classic Petrophysics. In the next step, by the aid of high resolution evaluation methods it will be shown that top most 1st meter can be perforated.

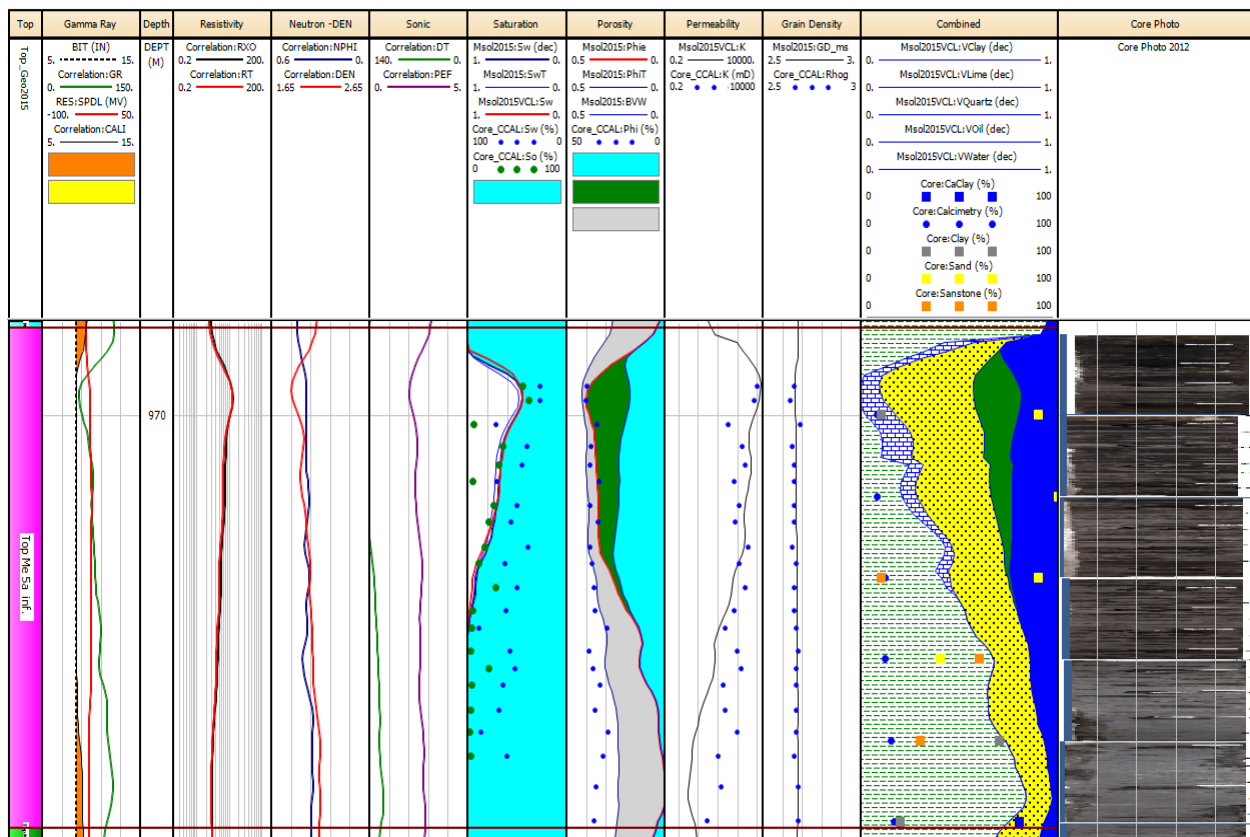


Figure 16 Petrophysical Evaluation Integrated by Core Data

As mentioned in previous chapter, core photo was used for defining thin layer thickness for the earth model. Based on the workflow described in chapter 3, initial values for Rt was generated to be incorporated in earth model. All the building blocks are now available to perform forward modeling. Forward model was performed by convolution of earth model and tool response function to generate a calculated deep resistivity. In each iteration the difference between calculated log and measured log is considered as incoherence function. Incoherence function is optimized by the aid of genetic algorithm to produce best possible match. The process is illustrated in the following figures.

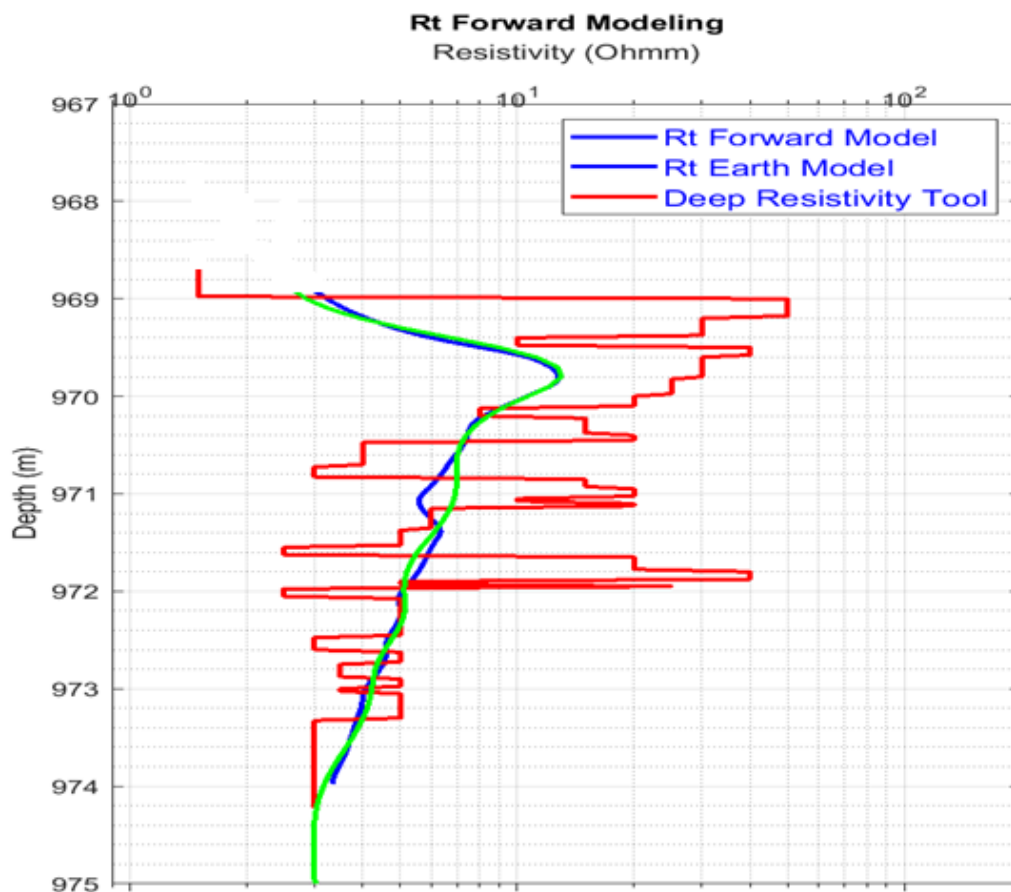


Figure 17 Iterative Inversion

The match improved step by step till the criteria incoherence to be less than tolerance is met. Then the iteration is stopped. Based on the result it is observed to top most 1st meter is also reservoir and can be perforated as is confirmed by the above figure; the Earth Model Rt - red curve - would be the resistivity which would be used for interpretation. The range of earth model Rt is higher than the recorded resistivity so it guaranty to interpret high oil saturation up to top most part of reservoir – at 696 m. Meanwhile it reads low in bottom parts of interval even in sand zones, so it is expected to have higher water saturation in lower parts of interval. The production test confirms presence of oil. Oil production test result proved 70% oil and 30% water.

Conclusion

1. It was concluded that classic Petrophysics is not able to determine true hydrocarbon pore thickness in thin layer shaly sand interval due to the fact that since layer thickness is less than log resolution so several layers are averaged at each depth and the log reading would be only an average value and is not representative for each of them.
2. It was shown that based on classical Petrophysical approach, hydrocarbon pore thickness is underestimated. Integration of core was an improvement.
3. It was shown based on forward modeling which is the main subject of this thesis the maximum hydrocarbon thickness should be 4 meter. In reality only 3 meter was perforated before production. The result of current research showed the top most 1st meter from top of reservoir which was the most prolific interval was not perforated.

4. It is recommended based on the results that top most 1st meter should be perforated.
5. Making an accurate earth model needs data as well as experience. The initial values for earth model would never results in a good match. On the other hand a match although is necessary but is not sufficient; the results should be verified by other data as core, advanced logs, production test results, etc. this is the drawback in majority of previously published work in this area.

Original Contribution

1. A very important power point of this research is integration of fullset, RCAL, SCAL, core photo and production test results which have not been reported in any of previous published papers. Therefore validity of earth model is confirmed by core photo to avoid non- uniqueness problem.
2. Besides, the optimization procedure of genetic algorithm was applied for automation of iterative inversion for the first time in this research domain which serves as the novelty of this research thesis. Genetic algorithm is a mathematical optimization algorithm inspired by natural evolutionary selection principles. It is widely applied in different optimization processes and proved to be a successful tool for various engineering areas.
3. A computer code developed in this research to perform the mentioned simulation. This is because these codes are not available in any of the

commercial softwares. The applied method in this thesis is called “SHARP PROCESSING” by Schlumberger and is charged several thousand euro per meter analysis. The companies which have developed same technology have patented it and are reluctant to reveal details involved. Different authors and scholars who have presented their results normally had not revealed the whole details involved. It made serious problems for the author of this work during developing the computer code as the code was not converging; finally it was cleared for the author that some key parts were not mentioned in previous papers.