Well to Seismic Ties Modeling with the Adaptive Log Analysis*

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Abstract

Data integration is a key step for accurate seismic interpretation and reservoir characterization. Hydrocarbon reservoirs are characterized by seismic, well-log, and petrophysical information, which is dissimilar in spatial distribution, scale, and relationship to reservoir properties. Acoustic and density logs could be absent in logging suite. In such case several techniques are applied for acoustic and density logs modeling. We propose adaptive model for elastic properties simulation. Developed algorithm is grounded on theoretically proved petrophysical laws and regularities in contrast with elastic properties simulation techniques which are based mainly on empirical relationships between petrophysical parameters.

According to the adaptive technology it is possible to describe a large number of factors that characterizes reservoir sedimentation conditions, mode of occurrence, epigenetic transformation. The base of the adaptive log analysis technology is the petrophysical invariant (normalized effective porosity or dynamic). It could be determined with log data (acoustic log, density log, compensated neutron log, spontaneous potential log and gamma ray log).

The adaptive log analysis technology tunes log analysis algorithms according to the tool response in formation natural occurrence conditions. Slowness and density of the reservoir can be estimated with characteristic values of acoustic and density log responses.

Examples of the acoustic impedance adaptive simulation and synthetic seismograms modeling were carried out for Jurassic reservoirs - sandstones with complex mineral composition. Acoustic impedance was calculated by two ways. First one is product of P-wave

velocity and density; the second one is carried out using adaptive model with spontaneous potential (SP) log, gamma-ray (GR) log and compensated neutron log (CNL).

Petrophysical invariant was calculated from acoustic and formation density logs and SP, GR and CNL for determination of simulation model accuracy characteristics. Calculated acoustic impedance was convolved to the synthetic seismogram in both cases. The excellent traces convergence indicates the high accuracy and reliability of the developed technology. The adaptive model is valid for granular reservoir rock (clastic or carbonate) only.

Calculated elastic parameters can be used to obtain wavelets, restore low-frequency component that is absent in seismic data as well as to analyze the seismic inversion results.

Introduction

Data integration is a key step for accurate seismic interpretation and reservoir characterization. Hydrocarbon reservoirs are characterized by seismic, well-log, and petrophysical information, which is dissimilar in spatial distribution, scale, and relationship to reservoir properties. However, different scales of measurement should be taken into account while preparing data for integration.

Well logs are calibrated to seismic data through check-shot-based drift corrections to the integrated acoustic transit times. Then synthetic seismograms are compared against real seismic data. Synthetic seismograms are generated with acoustic and density log data. Seismic (acoustic) impedances to pressure waves and shear waves are estimated with these logs and determine the AVO character of seismic reflections.

Acoustic and density logs could be absent in logging suite. This is especially critical for geo modeling, when old well logs data are in use. In such case several techniques are applied for acoustic and density logs modeling.

We propose adaptive model for elastic properties simulation. Developed algorithm is grounded on theoretically proved petrophysical laws and regularities in contrast with elastic properties simulation techniques which are based mainly on empirical relationships between petrophysical parameters.

The Adaptive Technique of the Acoustic Impedance Estimation

In case of density log absence, relation between P-wave velocities and densities are applied for densities determination. This approach to densities determination is based on the generalization of regularities, which are found from accumulated empirical data diversification. Those regularities indicate relations between clastic rocks velocity V_P and density ρ. Gardner gave following equation for density estimation [Garner, Garner, Gregory, 1974 (1)]:

$$\rho \approx aV_P^b. \qquad (1)$$

The relationship introduces two lithology dependent empirical parameters a and b that can be obtained by calibrating the model with experimental data. Gardner's equation has the tendency to the over-estimation of sandstones densities and to the under-estimation of shale densities. As a result, for more accurate densities estimation it is necessary to identify empirical relations with data in a given region or area for each well separately. This fact significantly complicates the acoustic impedance calculation in conditions of limited prior geophysical and petrophysical information. Many other techniques for elastic properties modeling are based on empirical relations and comparisons too. The adaptive log analysis is devoid of stated disadvantages [Kozhevnikov, Kovalenko, 2010 (2)]. According to the adaptive technology it is possible to describe a large number of factors that characterizes reservoir sedimentation conditions, mode of occurrence, epigenetic transformation, etc. with three compositive parameters μ0, Δμ, M (μ0 – framework water-holding capacity, Δμ – cement water-holding capacity, M – maximum reservoir rock porosity or framework porosity). These parameters characterize correlation regularities range for heterogeneous granular reservoir rocks with complex polymineral composition. It is no information loss, and completeness of the reservoir rocks properties variety description persists. The base of the adaptive log analysis technology is the petrophysical invariant (normalized effective or dynamic porosity). The petrophysical invariant could be determined with log data (acoustic log, density log, compensated neutron log, spontaneous potential log and gamma ray log) in following form [Kozhevnikov, Kovalenko, 2010 (2)]:

$$\Psi = \frac{\Re(\varphi;\Re_c) - \Re(\mu;\Re_c)}{\Re(M;\Re_M) - \Re(\mu;\Re_c)}, \tag{2}$$

where $\Re(\varphi;\Re_c)$ – the value of reservoir rock petrophysical parameters with current total porosity φ;

$\Re(M;\Re_M)$ – the reservoir rock petrophysical parameter in case of $\varphi = M$;

$\Re(\mu;\Re_c)$ – the petrophysical parameter in case of the effective porosity absence ($\varphi = \mu$, clay content is maximum).

Density, neutron porosity, slowness, natural gamma ray activity and dynamic spontaneous potential amplitude act as petrophysical parameters.

The validation of the petrophysical invariant as well logging suite data interpretative parameter allows ascending from poorly formalized empirical algorithms to log analysis algorithms, relying on analytical petrophysical reservoir models reflecting the totality of rock formation conditions. The principle of petrophysical invariance makes possible to reveal and present stable analytical relationships between interpretative parameters and reservoir properties of complex formations in generalized form. So the main advantage of such approach is analytical reservoir properties modeling possibility.

Figure 1 shows relations between slowness, P-wave velocity, density and the petrophysical invariant. Apparently characteristic parameters could be estimated from a comparison of the acoustic impedance and the petrophysical invariant. Characteristic acoustic and density log responses (markers) are determined there. Hence the fundamental possibilities of the acoustic impedance determination by adaptive log analysis models take place.

The adaptive log analysis technology is based on the granular reservoir rock petrophysical model and tunes log analysis algorithms according to the tool response in formation natural occurrence conditions.

The petrophysical invariant is calculated as normalized effective or dynamic porosity, balanced according to shares of each «simple» well log’s dispersions (spontaneous potential log, gamma ray, compensated neutron log) [Deshenenkov, Kozhevnikov, Kovalenko, 2010 (3)].

This means that slowness (P-wave velocity) as well as density could be determined on the base of the petrophysical invariant with application of the adaptive log analysis technology.

Slowness ΔT and density ρ of the reservoir can be estimated with characteristic values of acoustic and density log responses:

$$\Delta T(\varphi; \Delta T_C) = \Psi[\Delta T(M; \Delta T_M) - \Delta T(\mu; \Delta T_C)] + \Delta T(\mu; \Delta T_C), \tag{3}$$

$$\rho(\varphi; \rho_c) = \Psi[\rho(M; \rho_M) - \rho(\mu; \rho_c)] + \rho(\mu; \delta_c). \tag{4}$$

Then equation for acoustic impedance calculation will have following form:

$$Z(\varphi; Z_C) = 10^6 \frac{\Psi[\rho(M; Z_M) - \rho(\mu; Z_C)] + \rho(\mu; Z_C)}{\Psi[\Delta T(M; Z_M) - \Delta T(\mu; Z_C)] + \Delta T(\mu; Z_C)}. \tag{5}$$

It should be noted that presented equation is based not on empirical log analysis techniques and algorithms, but on physically grounded analytical models. Such algorithms and methods could be applied everywhere, but not only within the definite region or area, where those algorithms and correlation relationships were founded. The validation of granular reservoir petrophysical model, which is a base of the adaptive technique, is given below [Deshenenkov, Kozhevnikov, Kovalenko, 2010 (4)].

Petrophysical Modeling of Oil and Gas Reservoirs

Petrophysical invariant Ψ is the main log interpretative and petrophysical parameter, which reflects the wide range of factors that characterizes the sedimentation conditions, occurrence and secondary lithogeochemical transformations of reservoir rocks. This range includes: pore size distribution, surface area, mineral composition and fluid-holding capacity of the framework and cement, thermal and baric conditions, etc. [Kozhevnikov, Kovalenko, 2000 (5)], [Ringrose, 2008 (6)].

“Conservation principles” derived from laboratory core analysis are used to validate petrophysical models. Changes in mineral composition and properties of granular reservoirs cement affect reservoir properties and the capillary pressures distribution that determine the direction of fluid flows (Figure 2-C, 2-D, 2-F). Characteristic parameters of the model {share of residual water hold by the framework $\mu0$; share of water hold by the cement $\Delta\mu$; porosity of the framework M} allow studying petrophysical principles and relations directly on the core analysis results (Figure 2-E).

Mineral composition heterogeneity of the Western Siberia reservoirs cement is subject to certain regularity. This regularity acts as changes in the content of clay minerals in the cement with depth increase. In case of hydromica kaolinization 40% of the substance goes up to the solution. The process is accompanied with a significant increase in pore space volume and, as a consequence, with a significant improvement of reservoir rock properties. The reduction of the kaolinite relative contribution to the total clay minerals content decreases reservoir properties, which consist of the cement water-holding capacity increase and decrease of effective porosity and permeability. Comparisons of clay minerals content are plotted for samples with equal water-holding capacity. According to the proposed petrophysical model it is expected the transition from the nonswelling cement minerals to the swelling ones with reservoir water-holding capacity increase (Figure 2-G).

The Validity Argumentation of the Residual Water Saturation Model

The granular reservoir petrophysical model is applicable in case if the sum of total porosity and shale volume is a constant that is equal to porosity of the framework. It is assumed that sand and aleurite fraction (larger than 0.01 mm) make up the framework of the reservoir, while the clayey and pelite fractions (less than 0.01 mm) compose the cement and fill capacity of the framework. The presence of the cement solid component and bounded water in the framework goes to reservoir properties reduction. Figure 2-B shows the comparison of shale volume with total porosity of the Jurassic fine-grained sandstones. Shale volume is determined with grain size analysis; porosity is evaluated with saturation technique. Between these parameters there is a clear inverse relation, and their sum is equal to the framework porosity; this fact is completely corresponds to the “Conservation principles” points.

Comparisons of the sand and aleurite contents prove the point that fractions less than 0.01 mm are assigned to the cement. Figure 2-A compares the sand and aleurites volume contents for sandstones from different regions. It is difficult to expect high correlation coefficients due to known errors associated with the preparation of test charges. However, this comparison indicates that the sum of the sand and aleurites volume contents is a constant. Thus, framework porosity is stable with grain size variation and this fact is a second point of petrophysical model validity argumentation.

The close inverse correlation between the sand content and aleurite fractions content is due to the substitution of one fraction to another one within the particular reservoir. Grain size analysis results and their comparison with reservoir properties can identify limitations of the reservoir model applicability. Framework capacity can be taken as a constant value for the particular reservoir, even if the framework fraction composition varies with depth. The fine-fraction has main influence on log response and determines reservoir properties in case if mineral composition of the framework doesn't change.

Examples of Well to Seismic Ties Modeling

Figure 3 shows an example of the acoustic impedance adaptive simulation and synthetic seismograms modeling in Jurassic reservoirs – sandstones with complex mineral composition. Acoustic impedance was calculated by two ways. First one is direct product of P-wave velocity and density; the second one is carried out using adaptive model with spontaneous potential log (SP), gamma-ray log (GR) and compensated neutron log (CNL).

Petrophysical invariant was calculated from acoustic (AL) and formation density logs (DL) and SP, gamma-ray and compensated neutron logs for determination of simulation model accuracy characteristics. Calculated acoustic impedance was convolved to the synthetic seismogram in both cases. The excellent traces convergence indicates the high accuracy and reliability of the developed technology. The adaptive model is valid for granular reservoir rock (clastic or carbonate) only.

Results and Conclusions

Analytical equations for the acoustic impedance determination according well logging data are obtained. Two ways for the acoustic impedance calculation in limited prior information conditions are proposed. Notably, if the standard approach requires knowledge of slowness or density in every well, then in case of adaptive approach the impedance can be calculated while acoustic and density logs unavailability. It is only necessary prior characteristic slowness and density set according to the neighboring wells data or petrophysical zoning information.

The validation of proposed granular reservoir petrophysical model includes following. There is a clear inverse relation between the shale volume and total porosity, and their sum is equal to the porosity of the framework. The close inverse correlation between the sand content and aleurite fractions content is due to the substitution of one fraction to another one within the particular reservoir.

Proposed petrophysical model makes possible to predict effective porosity with log data in reservoir natural occurrence conditions. Effective porosity (petrophysical invariant) is considered as a basic interpretative parameter for log analysis in case of complex polymineral reservoirs.

Elastic parameters Vp and ρ calculated with adaptive technique are characteristics that are directly related to reservoir properties. They can be used to obtain wavelets, restore low-frequency component that is absent in seismic data as well as to verify and analyze the results of seismic inversion.

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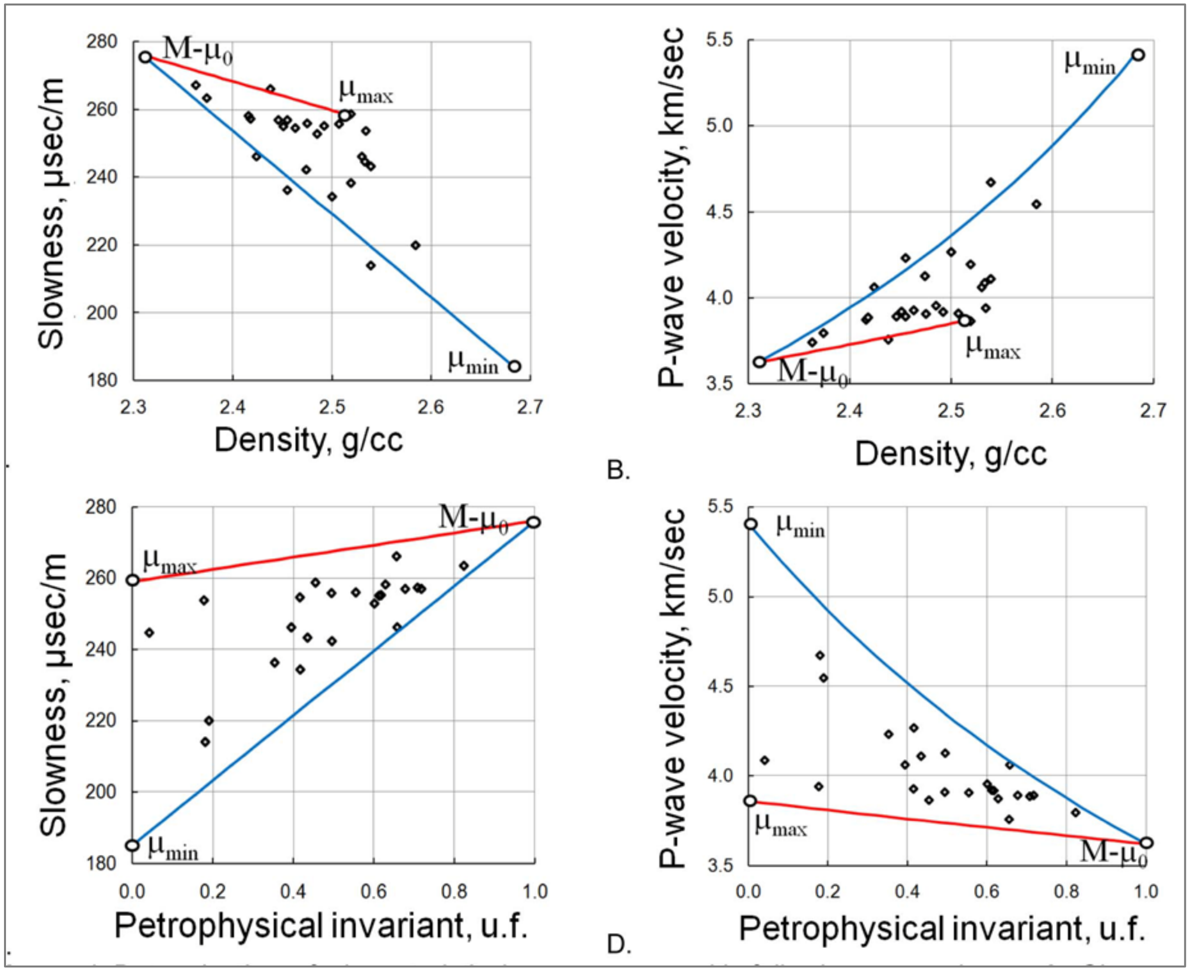

Figure 1. Determination of characteristic log responses with following comparisons: A. Slowness vs. Density, B. P-wave velocity vs. Density, C. Slowness vs. Petrophysical invariant, D. P-wave velocity vs Petrophysical invariant.

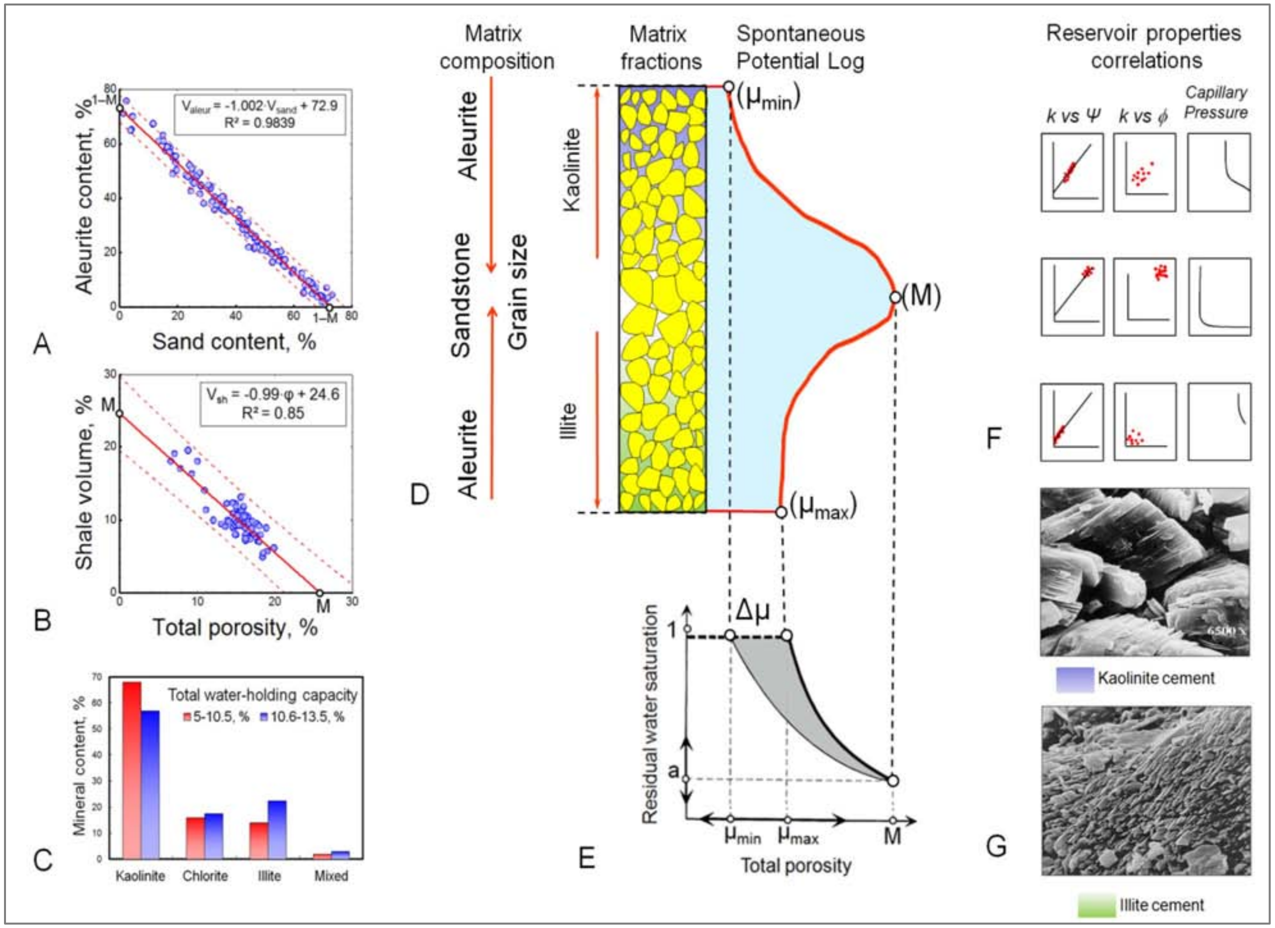

Figure 2. Correspondence between spontaneous potential (SP) log amplitudes and characteristic values (μ_{max}, μ_{min} and M) of the petrophysical reservoir model (D, E), changes in the content of clay minerals according to different cement water-holding capacities (C, G). “Conservation principles” of fine fractions (A) and (B) and corresponding correlation changes in relation between absolute permeability, petrophysical invariant and total porosity, capillary pressure and current water saturation (F).

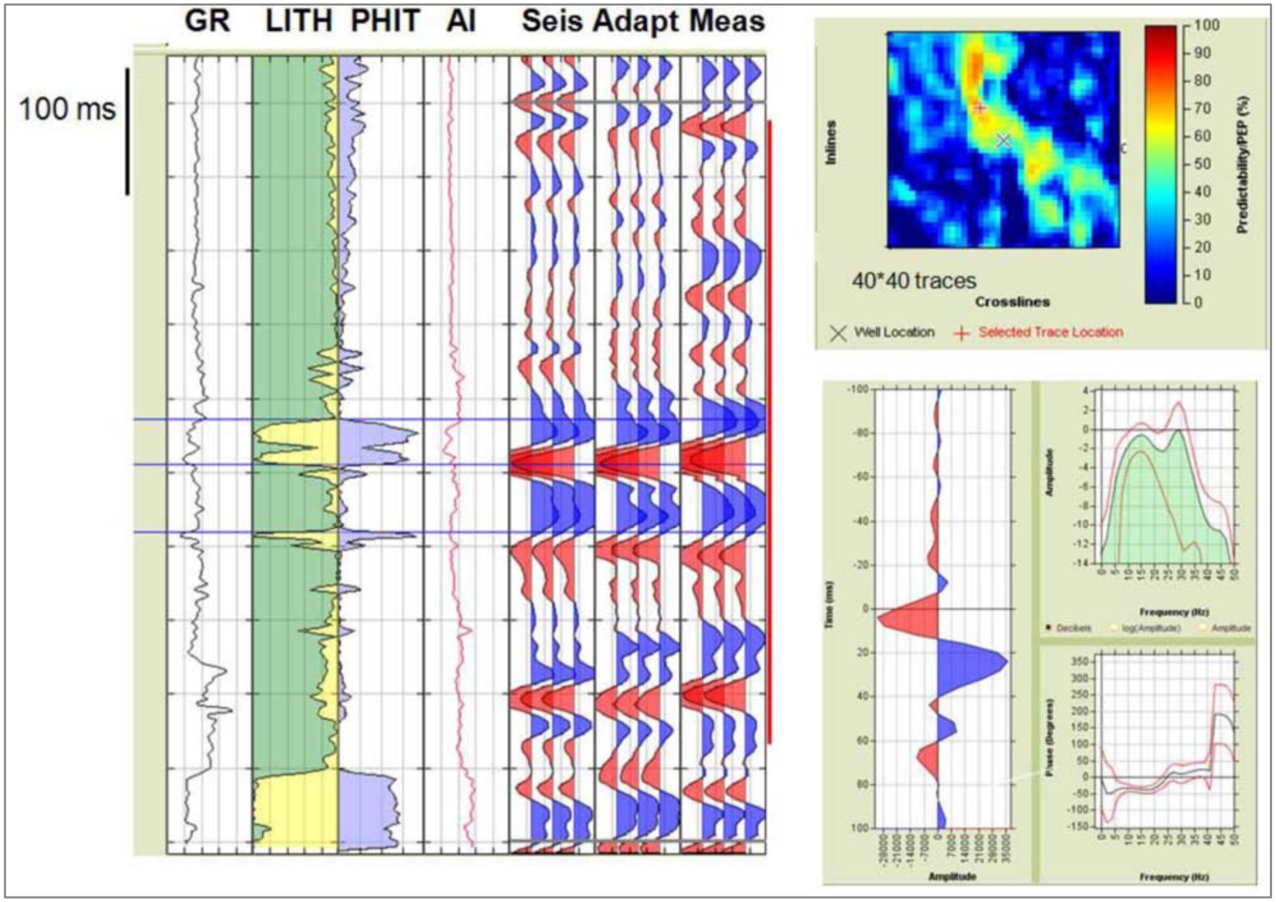

Figure 3. Results of the well to seismic ties modeling: 5th track – seismic trace; 6th track – acoustic impedance (AI) with SP, GR and CNL (adaptive technique), 7th track – AI with AL and DL (measured data).