Calculating shear wave velocity from compressional wave to estimate geomechanical parameters in a turbidite reservoir of Campos Basin - Southeast Brazil

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Abstract

To drill new wells in oilfields it is necessary to use a good design, which requires, beside detailed knowledge of geological and structural aspects, stress state of rocks and fluids present in the pores. Data analyzed for this purpose are derived from seismic, correlation between well logs or laboratory measurements on rock samples. All these evaluations have in common estimates of mechanical parameters of rocks through of acoustic properties, as propagation velocities of compressional (V_P) and shear (V_S) waves. Often, however, data set does not include V_S, or, in specific case of well logs, this parameter is not even measured. Thus, our study aims to establish a methodology to estimate V_S from V_P considering a polynomial fit with least squares technique in a turbidite reservoir of Campos Basin - Southeast Brazil. The results show that linear fit is better than the well known method of Castagna et al. (1985, 1993). After this, mechanical parameters calculated from simulated V_s of this oilfield show that one of the three studied wells is out of the drilling operational window of stability, possibly because it was calculated with noisy data, being therefore better adopt fracture pressure as upper bound of this framework.

Introduction

Well engineering is always looking for supports to develop projects for new wells to be drilled in an oilfield. This is done, mainly, through estimative of mechanical properties of rocks drilled in neighboring wells with similar geology. Geomechanical parameters such as horizontal stresses, stresses acting on the walls of the well, fracture pressure and its propagation, pore pressure, etc., can be derived from the ratio between the V_p and V_s (Bassiouni, 1994).

V_p data are usually acquired from well logs, laboratory measuments in rock samples or resulting from seismic data. However, the same situation does not happen with V_s data, what is usually a parameter not available in datasets to determine the dynamic elastic modulus of the geological media. Even when the measurement is carried out by logs, often, only small fragments of few wells are measured, mainly to characterize the reservoir in production or injection zones. Consequently, it is valid the attempts to simulate V_s from V_p in a reliable way, either by well and surface data (Goodman & Connolly, 2007). The relationship between these two velocities is essential to determine the lithology and mechanical parameters of rocks. In literature, it exists a wide range of relationships and techniques for predicting V_s, which, at first, appear quite distinct, but are reduced mainly two considerations (Mavko et al., 2003): a) empirical relationships between V_p, V_s and porosity (ϕ) for a reference fluid that saturates the rock - usually 100 % saturated by water or dry; b) Gassmann (1951) relation used to map these empirical relationships with other conditions of fluid saturation, especially in the presence of hydrocarbons.

Although some effective models can be used to predict V_s in function of V_p based on an idealized pore geometry, the most reliable and the most commonly used are fits based on experimental laboratory data or logs, or both. The most important and useful function of the theoretical methods is to extend such empirical relationships for different fluids saturating pores of the rock or different frequency measurement of V_s in function of V_p.

In this work, we build on the results of Greenberg and Castagna (1992), who showed a relationship to estimate V_s from V_p in sections of multimineral rocks saturated with water (S_w = 100%) based on empirical polynomial relations for purely monomineral lithologies (Castagna et al, 1993). In composite lithologies, saturated with water, V_s is approximated to a simple arithmetic and harmonic mean of each constituent of a particular lithology (sandstone, shale, limestone or dolomite), as shown in Equation (1):

$$V_s = \frac{1}{2}\left\{\left[\sum_{i=1}^{L} X_i \sum_{j=0}^{N_i} a_{ij} V_P^{\,j}\right] + \left[\sum_{i=1}^{L} X_i \left(\sum_{j=0}^{N_i} a_{ij} V_P^{\,j}\right)^{-1}\right]^{-1}\right\}, \qquad (1)$$

where $\Sigma X_i = 1$ ($i=1$ to 4) is the volumetric fraction of each lithological component; L is the number of different lithological constituents; a_{ij} *is the* empirical regression coefficients; N_i *is the* polynomial order of the lithologic constituent i; V_p, and V_s are compressional and shear velocities (km/sec), respectively, in multimineral rocky compound saturated by water. Castagna et al. (1985) proposed Equation (2) for each component i, whose coefficients are shown in Table 1:

$$V_s = a_{i0} + a_{i1}.V_p + a_{i2}.V_p^2, \qquad (2)$$

where a_{i2}, a_{i1} and a_{i0} are coefficients. It is important to note that this relationship applies only in rocks 100% saturated with formation water (brine). To estimate V_s from measured V_p for other fluid saturations (oil or gas, or combination of them and water), equation of Gassmann (1951) should be used in an iterative manner, as shown by Mavko et al. (2003). The method, however, requires knowledge of lithology, porosity, saturation, elastic modulus, density of the mineral constituents and pore fluids.

Thus, after estimates V_s from V_p in a reliable way, it proceeds to calculate mechanical parameters or elastic constants, which are needed to evaluate the operating window of stability in drilling wells. Thus, by calculating, initially, parameters as Poisson ratio (Equation 3), Young's modulus (Equation 4) and Biot constant (Equation 5), it can be obtained parameters such as absolute pore pressure (Equation 6), vertical stress (Equation 7) and minimum horizontal stress (Equation 8) (Tiab & Donaldson, 2004).

$$\nu = 0,5\frac{\left[\left(\frac{V_p}{V_s}\right)^2 - 2\right]}{\left[\left(\frac{V_p}{V_s}\right)^2 - 1\right]}, \tag{3}$$

$$E = \left(1,34x10^{10}\right)\left[\frac{\rho}{\left(\Delta t_p\right)^2}\right]\left[\frac{((1+\nu)(1-2\nu))}{(1-\nu)}\right], \tag{4}$$

$$\alpha = 1 - \left(\frac{k}{k_r}\right), \tag{5}$$

$$P_p = 0,17.\rho_p.D, \tag{6}$$

$$\sigma_V = 1.422\left(\rho_W.LDA + \int_0^{z'} \rho dz'\right), \tag{7}$$

$$\sigma_h = \left(\sigma_v - \alpha P_p\right)\left[\frac{\nu}{1-\nu}\right] + \alpha P_p, \tag{8}$$

where ρ e Δt_p are the density and sonic logs in g/cm^3 and km/sec, respectively; k_r = 3.0 x 106 psi is the radial pressure; ρ_p = 8.6 ppg is the normal gradient pore pressure as it is common practice in well engineering; D is the actual vertical depth of the well; ρ_W = 1.033 g/cm^3 is the density of water; the overhead gradient (Ovb) is simplified to 1 psi/ft, so that LDA is the sea water layer and z' the vertical depth below the seafloor, these two latter in meters.

Another important factor to be considered in our approach is the calculation of the shaliness volume (Vsh), as proposed by Larionov (1969), which begins calculating the Index of Gamma Ray – IGR (Equation 9) and selecting type of rock, to evaluate Vsh (Equation 10):

$$I_{GR} = \frac{GR_{\log} - GR_{\min}}{Gr_{\max} - Gr_{\min}}, \tag{9}$$

$$V_{sh} = \frac{I_{GR}}{A_{GR} - (1 - A_{GR}).I_{GR}}, \tag{10}$$

where GR_{log} is gamma ray log (ºAPI); GR_{min} and GR_{max} are, minimum and maximum values for GR log, respectively; AGR = 1 to Tertiary rocks, 2 for pre-Tertiary rocks and 3 for post-Tertiary rocks.

Therefore, knowledge of V_p and V_s in subsurface geological media is extremely important to estimate properties such as σ_h, which is active in the wall of a vertical well and is one of the maximum pressure limits that can be adopted by well designer to apply the drilling fluid throughout the time that well is open, i.e., before casing (Tiab & Donaldson, 2004). Thus, besides the drilling process, evaluation of σ_h is essential for operations such as changing of drilling fluids, gravel packing and hydraulic fracturing and reservoir stimulation (Tomasi et al., 2006).

It is reasonable to realize that these estimates may provide a good assessment of operational limits for drilling a new well, helping to avoid problems as a kick until a blow out or accidental fractures, which can be followed by total fluid loss during drilling or open hole completion. This can result in much wasted time due to unwanted permanent abandonment of the well with the loss of sea structures, semi-submersible rig or drillship, leaving the well in an uncontrolled way, which is reflected in corresponding financial losses amounting to millions dollars and/or losses in human lives (Rocha & Azevedo, 2007).

Thus, the present study stems from the need to determine mechanics parameters of rock to be drilled on new well projects in oilfields located in Campos Basin, through the analysis of correlation between their wells and thus determine the boundaries of the operational window for weight of the fluid, which can ensure accuracy with good stability during well drilling or completion operations.

Geological Context

The reservoir of this study belongs to a field in the Campos Basin, which is located in the eastern Brazilian coast (Figure 1). This makes part of Carapebus Formation of Campos Group and is part of a regressive marine sequence of the continental margin that in this basin covers the sedimentary record of Lower Tertiary to Recent (Bruhn, 1998). Lithologically, the reservoir consists of interbedded shales and turbidite sandstones, the latter being poorly consolidated and presenting as reservoir rock oligocenic age (Figure 2). Medium and fine sandstones, massive, poorly selected, with low levels of calcite cement and clay - siltic matrix and make up almost entirety this reservoir.

Despite its apparent homogeneity, the reservoir has important heterogeneities: a) impermeable layers with thicknesses typically less than 2 m, composed of interbedded dark - gray shale and very fine sandstones with parallel lamination and cross by ripples; b) horizons with sub - spherical calcite concretions; and, c) levels of intra - formational conglomerates intensely cemented by calcite (Bruhn,1998). The reservoir has a thickness of about 50 m, 30% of porosity, average permeability of 2.000 mD and connate water saturation of 11%. Log data and formation tests performed in exploratory wells indicate that, from the point of view of quality of rock, oligocenic sandstone reservoirs this field are little clay, with negligible cementation, excellent permoporosity characteristics, high productivity rates and having oil between 17 and 24 ° API (Campos, 1983).

Methodology

To conduct this study, we used a dataset from three wells ($P1$, $P2$ and $P3$), which has the basic suite of well logs (gamma rays - GR, resistivity - Rt, density - $RHOB$, neutronic porosity - $NPHI$, sonic - V_P), V_S log and lithology (Figure 3). Initially, least squares technique was applied to find relations between V_S and V_P, without any lithological restriction, obtaining regression coefficients for first and second degree polynomials (Tarantola, 2005). In sequence, we follow Castagna et al. (1985, 1993) approach, applying their empirical polynomials, relating V_S - V_P, for sandstones, shales, carbonates and dolomite lithologies. Finally, analysis of results of each attempt was made comparing calculated and measured V_S using Pearson coefficient - R^2 (Moore, 2007), and, once determining reliably V_S, mechanical parameters of operational window were obtained to help drilling of new wells in oilfield above mentioned.

Results

Initially, we plotted $GR, Rt, RHOB, NPHI, V_P$ and V_S logs, beside lithology, for each well (Figure 3). Using GR, Rt and $RHOB$ logs it was possible to trace the reservoir, which coincides very well with lithology (right of Figure 3). Hereafter, we analyzed correlation V_P - V_S for well $P2$, observing a big dispersion but, also, a nearly linear relationship between them as shown in the croosplot, with 3D graph showing this relation in depth (Figure 4). $P1$ and $P3$ wells also present greater dispersion, not shown in this article. This dispersion induced us to apply least squares in obtaining specific polynomial relationships for V_S - V_P. For well $P2$ yet, Figure 5 presents measured V_S (black) in all tracks, while, first track also shows linear V_S fit (blue), second track fit for second degree polynomial (red), and subsequent tracks, fits applying Castagna et al. polynomials for different lithologies (yellow).

Table 2 summarizes these results, observing that linear, second degree polynomial and dolomite fits have almost same R^2 magnitude, ranging between values -1 to 1. In sandstone, carbonate and shale polynomial cases, values are out of this interval. For well $P2$, graphs of Figure 6 demonstrate applicability of our approach, exhibit first track with linear V_S fit, followed by measured $V_P, \nu, E, \alpha, \lambda, K$ and G, many of them used to obtain mechanical properties as P_P, σ_V and σ_H. Even for well $P2$, Figure 7 presents, in sequence, calculated V_S, measured $V_p, \alpha, P_P, \sigma_V, \sigma_H$ and operational drilling window, latter showing its minimum P_P (red) e maximum σ_V (blue) limits. For this well, σ_H gradient (green) is inside operational window, happened the same for well $P3$ (not shown in this work). For well $P1$, however, σ_H is below P_P, and, if not explained as caused by diverse sources of errors, this can be interpreted as σ_H being inappropriate upper bound, becoming fracture pressure more convenient pressure as upper bound (Figure 8).

Conclusions

Results obtained in this study show that the best relationship between V_S and V_P, derived by least squares approach, is linear for 3 wells of turbidite reservoir of an oilfield of Campos Basin. Despite small difference in R^2 with the fit of second degree polynomial, we selected it because is simpler and crossplot shows, approximately, this tendency. This result is also better than those obtained with Castagna et al. method, because still dolomite polynomial has same magnitude of R^2, it is a wrong lithology. Other Castagna et al. polynomials have R^2 values out of real boundaries, demonstrating that such empirical approaches are applicable only with specific lithologies. Therefore, in projects for new wells where there is no V_s data, the best is performed a linear adjust with V_P, or, otherwise, utilize Castagna et al. coefficients with nearest lithology. Finally, estimated V_s enables calculation of elastic constants and acting stresses, which provides comfortable drilling operational window in the case of $P2$ and $P3$, but in the case of $P1$, best is take fracture pressure as upper bound.

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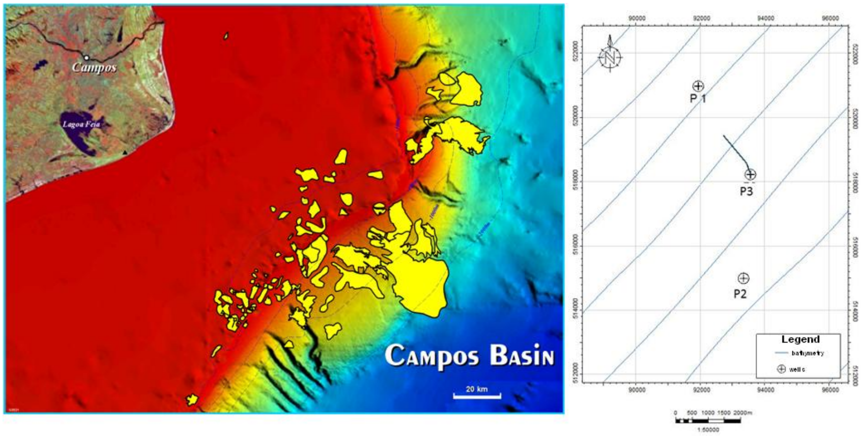

Figure 1. Map of (a) the Campos Basin (modified from Bruhn, 1998) and (b) distribution of wells.

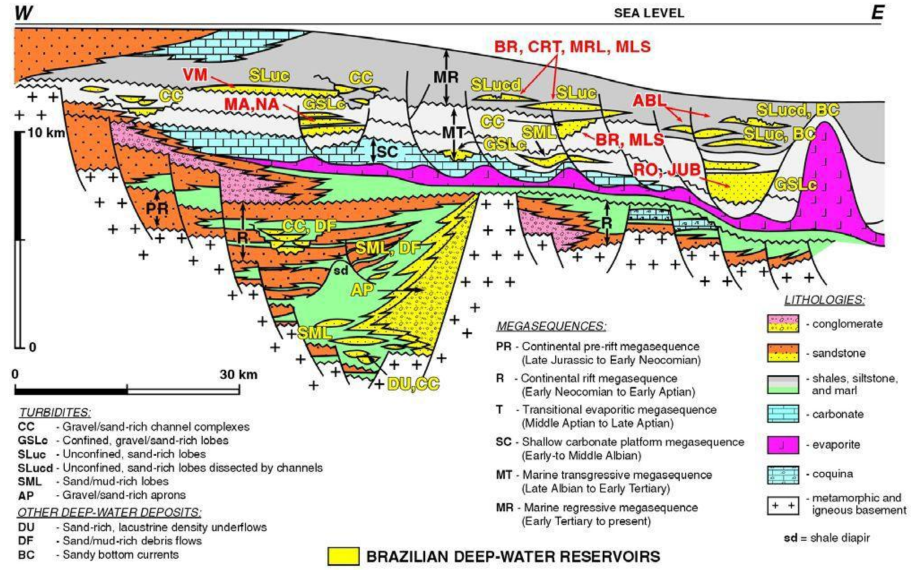

Figure 2. Main reservoirs of Campos Basin (modified from Bruhn, 1998).

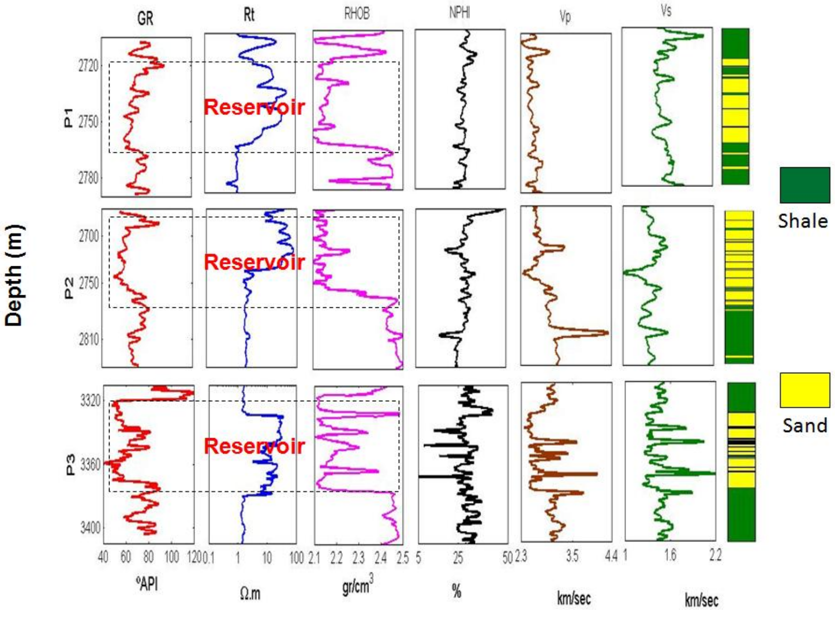

Figure 3. Logs and lithology of *P1, P2* and *P3* wells in Campos Basin.

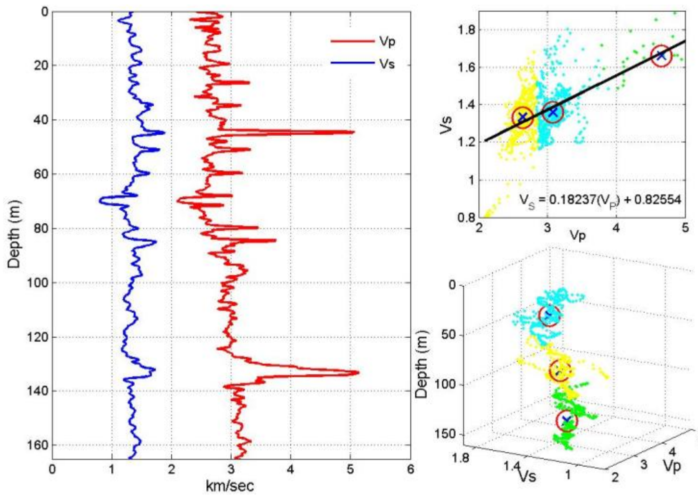

Figure 4. Plan and three-dimensional overview of V_P and V_S logs of well $P2$.

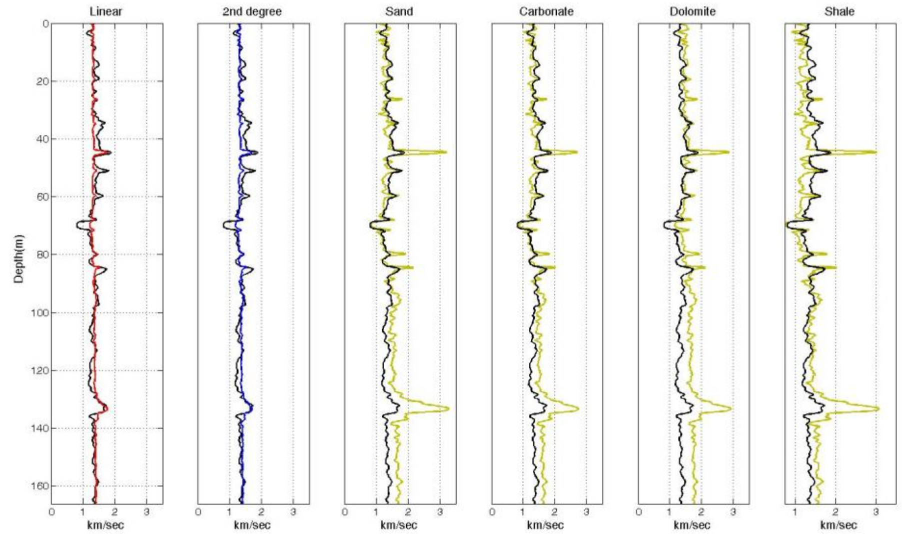

Figure 5. Linear, second degree and Castagna et al. (1985, 1993) polynomials fits for well $P2$.

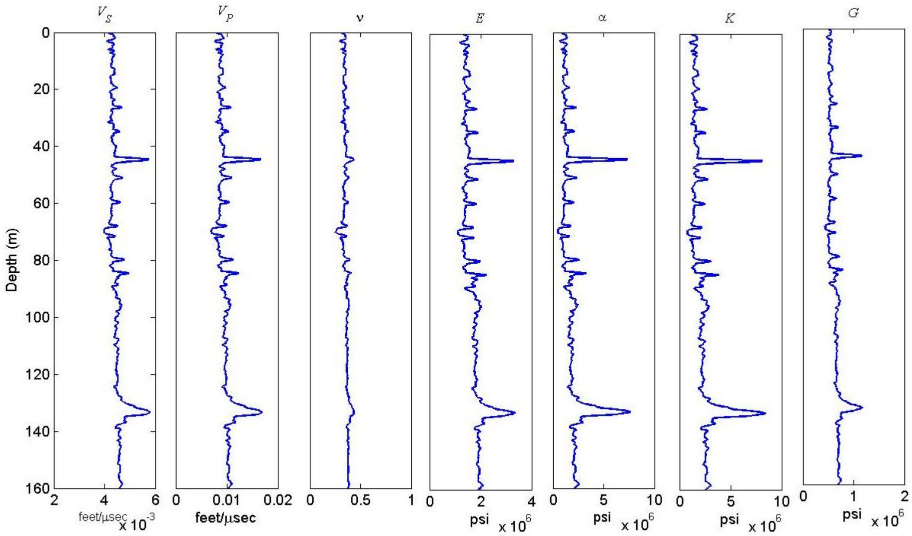

Figure 6. Estimated V_S, measured V_P and elastic constants calculated for well $P2$.

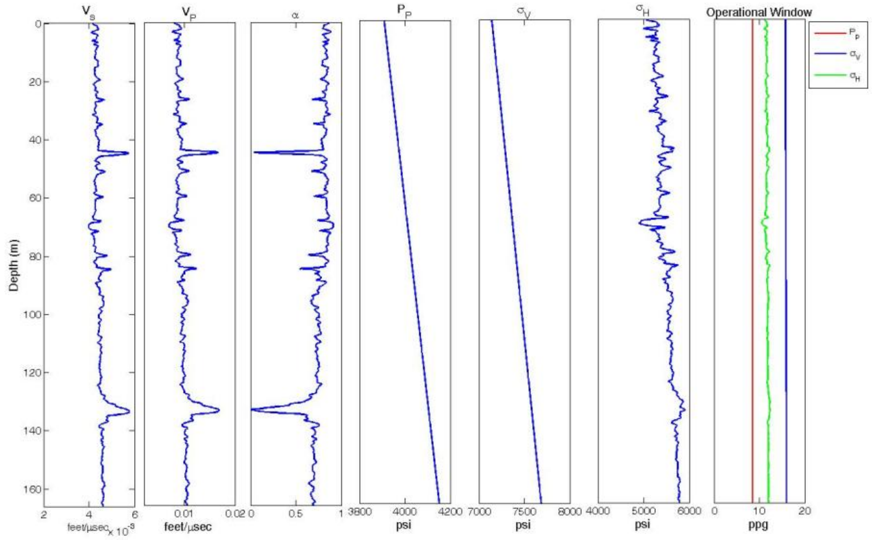

Figure 7. Estimated V_S, measured V_P, α, P_P, σ_V, σ_H and operational window for well *P2*.

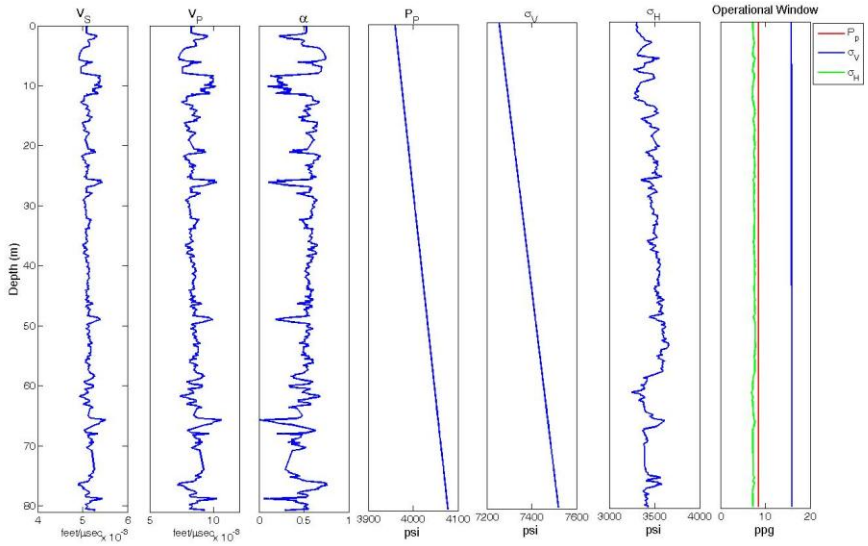

Figure 8. Estimated V_S, measured V_P, α, P_P, σ_V, σ_H and operational window for well *P1*.

Table 1. Castagna et al. (1985) coeficients**.**

i	Lithology	a_{i2}	a_{i1}	a_{i0}
1	Sand	0	0,80416	-0,85588
2	Shale	0	0,76969	-0,86735
3	Carbonate	-0,05508	1,01677	-1,03049
4	Dolomite	0	0,58321	-0,07775

Table 2. Resume of fits obtained for well *P2*.

Polynomial	a_2	a_1	a_0	R^2
Linear	0	0,18237	0,82554	0,2898
2nd Degree	-0,024619	0,34961	0,55124	0,2949
Sand	0	0,80416	-0,85588	-1,6090
Carbonate	0	0,76969	-0,86735	-1,0232
Dolomite	-0,05508	1,01677	-1,03049	-0,2343
Shale	0	0,58321	-0,07775	-2,6637