

Seismic signature of a permeable, dual-porosity layer

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ABSTRACT

Of the key reservoir properties, permeability seems to be the most elusive. Since the middle of the 90s, various seismic attributes have been proposed to map permeability by using detailed analysis of the frequency content of reflected wavetrains. Some attributes are expected to show a relative increase of high-frequency content with increased permeability; other attributes assume the opposite. Actually, both these trends were observed. A possible explanation of these observations is here derived from an effective model of a permeable dual-porosity layer enclosed by impermeable rocks. For such a model, the reflected wavetrain can be regarded as a sum of three components, one of which is related to acoustic-impedance contrasts, another to extra compliance caused by P-wave-induced fluid flows between fractures and intergranular pores with a high aspect ratio, and a third to the fluid-flow-induced, inelastic attenuation. In layered reservoirs, all the components tend to be frequency dependent, and the well-known dependence of the first component on the reflecting-layer thickness may strongly dominate the effects of permeability. Hence, predicting the behavior of a permeability attribute in a particular environment requires a modeling formalism that can be called permeability substitution by analogy with the widely used fluid-substitution technique.

INTRODUCTION

In dual-porosity rocks, the bulk of permeability is provided by fractures connected with each other and with high-aspect-ratio intergranular pores defined as equant pores by Thomsen (1995). When a P-wave propagates through such a rock, a partial fluid exchange occurs between fractures and pores. During the compression phase, fluid flows from the fractures to the pores, because the fractures are more compliant than are the pores. During the expansion phase, a part of the fluid accumulated in the pores is sucked back into fractures. The possibility of fluid exchange makes the rock more compli-

ant than it is in the case of isolated pores and fractures. The more permeable the rock, the more extra compliance appears.

If rocks were infinitely permeable, this effect of compliance increase and velocity decrease would be purely elastic. In rocks with finite permeability, such fluid flow takes some energy from the propagating wave, thus causing inelastic attenuation. As permeability tends to zero, the fluid flow ceases to exist, so the fluid-flow-induced inelastic attenuation should tend to zero as well. Hence, at some intermediate permeability, the inelastic attenuation reaches its maximum.

Supposedly, the decrease of P-wave velocity is an essential aspect of the seismic signature of a permeability increase in the case of dual porosity. A second aspect is the trend of inelastic attenuation. It has become obvious that the attenuation can either increase or decrease in response to the permeability increase, depending on which side of the attenuation maximum the particular value of the rock permeability is located. Also, when the fracturing is aligned, it is reasonable to expect both velocity and attenuation to be anisotropic.

These features of dual-porosity rocks have been intensely investigated theoretically. Thomsen (1995) expresses the elastic effect of P-wave-induced fluid exchange between (aligned) fractures and pores via an anisotropic fluid influence factor affecting the fracture-induced extra compliance normal to the fracture faces. No explicit dependence on permeability is included in Thomsen's (1995) formalism, because the fracture network is assumed to be infinitely permeable. Consequently, the fracture-induced extra compliance is just that of dry fractures, decreased to an extent that is defined by the rate of equalization of P-wave-induced extra fluid pressure over all the voids of the rock. At a very low frequency, when complete equalization is reached at each cycle, the rock compliance tends to that of dry fractures (maximum extra compliance). At a very high frequency, too little time is available for a noticeable fluid exchange between the fractures and the pores, so the rock behaves as if all the voids are isolated (minimum extra compliance). Accordingly, separate expressions are proposed for the fluid-influence factor at low (seismic), moderate (sonic), and high (ultrasonic) frequencies, thus giving a certain frequency dependence for the rock compliance normal to the fractures and, hence, for P-wave velocity and velocity anisotropy.

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Hudson et al. (1996) and Hudson et al. (2001) propose an alternative model covering dual-porosity rocks with mobile pore fluid and aligned fractures. The resultant anisotropic rock bulk modulus is a complex value, dependent, explicitly and continuously, on the rock-matrix porosity and permeability, pore-fluid incompressibility and viscosity, and frequency of the propagating P-wave. The imaginary part of the rock bulk modulus reflects inelastic, anisotropic attenuation. With regard to the Thomsen formalism, the attenuation is one more permeability-dependent aspect of the model.

The Thomsen (1995), Hudson et al. (1996) and Hudson et al. (2001) theories are based on an ellipsoidal-fracture model. This model is simple and convenient when the external background effective stress can be assumed invariable. However, in some important cases, e.g., in seismic monitoring of reservoir production (4D seismic), the fluid type and pore pressure, and sometimes permeability as well, are time variable, and these variations are target characteristics to be monitored. The model with ellipsoidal fractures is not quite adequate in the environment of varying effective stress, because the theoretical compliance of an ellipsoidal crack increases with compressive stress normal to the crack faces, whereas real fractured rocks exhibit just the opposite stress dependence, i.e., a decrease of compliance with increasing stress.

This latter, real form of effective-stress dependence is characteristic of fractures with rough faces (e.g., Greenwood and Williamson, 1966). Kozlov (2004) develops a model of dual-porosity rock with rough-face fractures accounting for Thomsen-style (i.e., elastic) fluid exchange between fractures and pores. Baransky et al. (2005), on the basis of the same arguments as in Hudson et al. (1996) and Hudson et al. (2001), expand the model so as to include inelasticity. The latter model depends on permeability exactly as in Hudson et al. (2001), but to describe its response to effective stress, opposite faces of fractures are assumed to be contacting each other via half-spherical asperities on the fracture faces. Deformation of the asperities because of external stress is expressed via Hertz-Mindlin's formalism (e.g., White, 1983).

In the cited papers, no definite techniques for extracting permeability estimates from reflection seismic data are discussed. Any such techniques suggested were based on rather general assumptions concerning the pattern of the seismic signature of fluid mobility.

Pisetski (1995) assumes that the reflection coefficients of seismic horizons attributed to hydrocarbon-bearing reservoirs are dominated by layering-concordant fractures. According to such a model, the increase of fracture opening (resulting in increased permeability and, consequently, increased hydrocarbon productivity) would lead to an increase of the absolute value of the reflection amplitude and a relative increase of the high-frequency content of the wavetrain reflected from within the reservoir.

Lichman and Goloshubin (2003) use, as a starting point, the well-known fact of the relative increase of the low-frequency content of the wavetrain reflected within (and in the vicinity of) a reservoir, especially if the latter is gas saturated. Among the parameters describing the reflected-wavetrain amplitude spectrum $|S(\omega)|$, the steepness $\partial|S(\omega)|/\partial\omega \equiv |S'|$ of the spectrum's left-hand slope is recommended as the attribute providing information on the fluid mobility within the reservoir. Later, the product $\omega(\partial|S(\omega)|/\partial\omega)$, averaged over the entire seismic frequency band, was shown to be proportional to the reservoir rock permeability (Silin et al., 2004).

Another attribute is developed within the framework of parameterized spectral decomposition (Davydova et al., 2005). Effective

permeability (i.e., permeability times permeable reservoir-layer thickness) is predicted by using the relationship $K_1 = \bar{S}_2/\bar{S}_1$, where $\bar{S}_1$ is the reflected-wavetrain amplitude spectrum integrated from the minimum frequency of the spectrum to its median frequency, and $\bar{S}_2$ is the amplitude spectrum integrated from its median frequency to the maximum frequency. It should be noted that elements of the theory for attribute $|S'|$ and K_1 time variant were initially developed (Silin et al., 2004; Baransky et al., 2006) by using models in which a single reflector is considered, whereas the reported successes are achieved in regions where reservoirs are represented by stacks of rather thin, alternating permeable and impermeable layers.

This paper concentrates on the effect of reservoir layering. An expanded rough-face-fracture model (Kozlov, 2004) is used to compare the contributions of the elastic and inelastic effects of P-wave-propagation induced fluid flows with the seismic signature of a single reservoir layer. The rough-face-fracture model is not as simple as that of ellipsoidal fractures. However, this model is more applicable to varying effective stress, which is important, e.g., in 4D seismic. The single-layer model is chosen because it would be too difficult to deal with an arbitrarily layered structure; on the other hand, a single layer is a better representative of a multilayered stack than is a single reflector. Two cases are considered: (1) when the increase of permeability increases the layer reflectivity (conventionally, type 1 layer) and (2) when the permeability increase leads to the opposite effect (type 2 layer).

The message of this paper is that, even for such a simplistic rock structure, (1) either acoustic-impedance contrasts at the layer boundaries or elastic extra compliance caused by pore-fluid mobility dominates the seismic signature of the layer, depending on the layer thickness and frequency range; (2) either an increase or a decrease of the relative high-to-low frequency content of the reflected wavetrain can result from a permeability increase, depending on the layer thickness and P-wave velocity, and (3) attributes $|S'|$ and K_1 respond to layers of types 1 and 2 in a different way. Hence, for better understanding of the geologic nature of permeability variations, permeability replacement modeling would be helpful.

THE MODELING FORMALISM

Assuming fractures to be azimuthally aligned, I use, for a starting point, then the same elastic stiffness matrix $\mathbf{C}$ of an effective horizontal transverse isotropy (HTI), (as is used in Thomsen, 1995 and Hudson et al., 1996):

$$\mathbf{C} = \begin{bmatrix} M(1 - \Delta_N) & \lambda(1 - \Delta_N) & \lambda(1 - \Delta_N) & 0 & 0 & 0 \\ \lambda(1 - \Delta_N) & M(1 - \xi^2 \Delta_N) & \lambda(1 - \xi \Delta_N) & 0 & 0 & 0 \\ \lambda(1 - \Delta_N) & \lambda(1 - \xi \Delta_N) & M(1 - \xi^2 \Delta_N) & 0 & 0 & 0 \\ 0 & 0 & 0 & \mu & 0 & 0 \\ 0 & 0 & 0 & 0 & \mu(1 - \Delta_T) & 0 \\ 0 & 0 & 0 & 0 & 0 & \mu(1 - \Delta_T) \end{bmatrix}. \quad (1)$$

Here, $\Delta_N = MZ_N/(1 + MZ_N)$ and $\Delta_T = \mu Z_T/(1 + \mu Z_T)$ are normal and tangential weaknesses (Bakulin et al., 2000), $M = K + 4\mu/3 = \lambda + 2\mu$, λ and μ are the Lamé constants, $\xi = \lambda/M$, and Z_N and Z_T are normal and tangential extra compliances. For a rock with rough-face fractures, the compliances can be expressed (Kozlov, 2004, equation 2 after some simplifications) as

$$Z_N = (2/3)Bce[c/(K^2p)]^{1/3}D, \quad (2a)$$

and

$$Z_T = (1 - 0.5\nu)ce\{2c/[3(1 - \nu)\mu^2p]\}^{1/3}. \quad (2b)$$

Here, e is a fracture density, c is the fracture roughness parameter, K is dry-rock bulk modulus, $p = p_s - np_f$ is effective stress, p_s is the lithostatic stress component normal to fracture faces, p_f is pore pressure, and n is the effective-stress coefficient, sometimes called Biot's parameter. Further, $B = [(1 + \nu)/(1 - \nu)]^{2/3}$, fluid-influence factor $D = \varphi D_1 + (1 - \varphi)D_2$, $\varphi = \phi/\phi_\Sigma$, ν is the Poisson's ratio of dry rock, ϕ is open porosity, and ϕ_Σ is total porosity. As seen, the first and second terms of the expression for fluid-influence factor D describe the effects of open and isolated porosities, respectively.

Of interest here is the open porosity only, i.e., the term with D_1 . By combining results of Thomsen (1995), Hudson et al. (1996), and Kozlov (2004), it can be shown (Appendix A) that

$$D_1 \approx \{1 + (2/3)[K_f/(\phi K)][K_s/(K_s - K_f)]BFce[cK/(3p)]^{1/3}\}^{-1}, \quad (3)$$

where K_s is bulk modulus of the rock-matrix material, K_f is pore-fluid bulk modulus, and

$$F = \{1 + [3/(2b)](1 - i)[\phi K_f \kappa / (2\eta_f \omega)]^{1/2}\}^{-1} \\ \approx [3/(8\pi)](a\phi_c/e)(1 + i)[2\eta_f \omega / (\phi K_f \kappa)]^{1/2}. \quad (4)$$

Here, ϕ_c , a , and b are fracture (or crack) porosity, average size, and average opening, respectively, κ is fractured-rock permeability, η_f is fluid viscosity, ω is angular frequency, and $i = (-1)^{1/2}$. Expression 4 implies rough-face penny-shaped fractures with an aspect ratio $b/a \ll 1/c$.

The imaginary component of F introduces inelasticity into the model described by equations 1–3. In particular, the extra normal compliance Z_N and P-wave velocity V_p are replaced with complex values $\tilde{Z}_N$ and $\tilde{V}_p$, respectively. (Tangential compliance is assumed to remain real.) The inelasticity causes intrinsic attenuation, defined by the inverse quality factor $Q^{-1} = \text{Im}(\tilde{V}_p)/\text{Re}(\tilde{V}_p)$, as well as P-wave velocity dispersion. This dispersion adds to the velocity alteration caused by the extra compliance that results from fluid exchange between fractures and equant pores. The presence of parameter a in the approximate expression for F would help account for the influence of fracture size on rock compliance, if fracture density e and aspect ratio b/a can be assumed unchanged when a varies. (This effect is predicted by Chapman (2003) and confirmed by physical modeling [Bakulin et al., 2004].) The $\tilde{Z}_N$ values calculated by using approximate versions of expression 4 are incorrect for permeabilities of less than 1 mD, so this expression should be used with caution.

Velocity anisotropy is described via normal and tangential compliances as in Kozlov (2004). Attenuation anisotropy is described (Appendix B) by analogy with the formalism proposed in Chichinina et al. (2006). The pore pressure is implicitly included in the model as a component of effective pressure p . As seen, the model represented by equations 1–4 accounts for all the main petrophysical parameters affecting the seismic wavefield, as illustrated in Figures 1–5.

MODELING THE SEISMIC SIGNATURE OF A PERMEABLE LAYER

Figures 1–4 show that the permeable-rock extra compliance Z_N and the P-wave velocity V_p decrease with increasing permeability, whereas the rock anisotropy increases with increasing permeability. For all three parameters, the highest gradient of the alteration is reached at rather small permeability values of 0.1–10 mD. In contrast, Figure 5 shows that the inverse quality factor Q^{-1} , as a measure of intrinsic attenuation caused by P-wave-induced fluid flow, increases markedly as permeability increases from 0.001 to 0.1 mD at $\omega/2\pi = 70$ Hz and from 0.001 to 0.01 mD at $\omega/2\pi = 10$ Hz. Then, with further increase of permeability to 1 D, attenuation decreases to nearly zero values. It should be noted that anisotropy is more affected by variations of effective stress than by variations of other parameters (Figure 4); the effect of the stress variation is most prominent at small values of the stress (Figures 1 and 2); in contrast to the rough-face-fracture model, a medium with the same background, but with ellipsoidal fractures as described, e.g., in Hudson et al. (2001), does not account for effective-stress variations (see Figure 4).

The reflection coefficient for a single boundary between permeable and impermeable rocks is governed by contrasts of acoustic impedance and attenuation at the boundary. Hence, the permeability dependence of the reflection coefficient can be deduced from the permeability dependencies of velocity and attenuation inherent in the permeable rock, as illustrated by Figures 3–5. However, limiting oneself to consideration of the seismic response of such a boundary will be misleading when interpreting a wavetrain reflected from a target interval represented by a stack of thin, alternating reservoir and seal layers. On the other hand, an attempt to analyze fully the response of a multilayered interval would not be suitable here, because

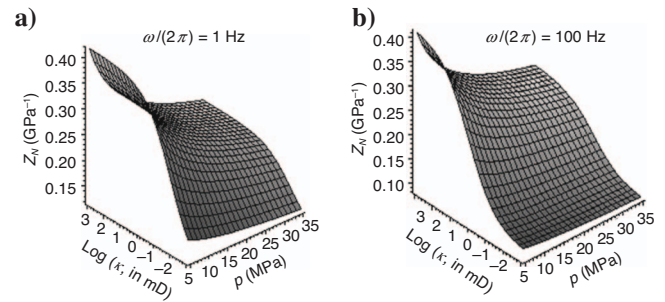


Figure 1. Fracture-induced extra compliance $Z_N(\kappa, p)$ at (a) 1 Hz and (b) 100 Hz. At 1 Hz, dependence of Z_N on effective stress p is more pronounced, and the steepest change of Z_N with permeability is shifted to lower permeability values.

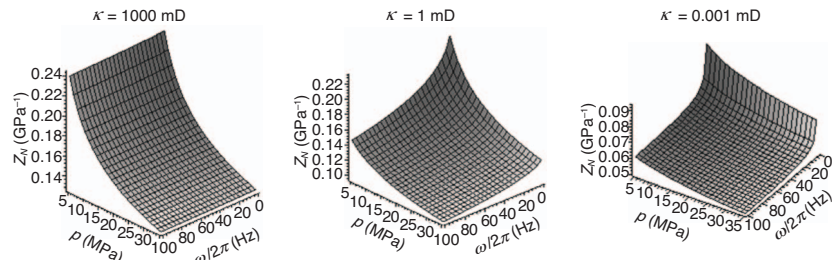


Figure 2. The shape of $Z_N(\omega, p)$ depends strongly on permeability.

the aim of this paper is limited to basic properties of the seismic signature of such an interval. The next step, then, is to consider the seismic response of a single permeable layer with varying thickness, enclosed in impermeable rocks, as depicted in Figure 6. For this, I use the scheme developed by Ursin and Stovas (2002) to calculate the reflectivity of a sequence of thin, standard-linear-solid layers. For a single attenuating layer, the reflection coefficient is reduced to

$$R(\omega, \tau) = \frac{\tilde{r}_1 + \tilde{r}_2 \exp(-i\omega\tau + Q_2^{-1}/2)}{1 + \tilde{r}_1 \tilde{r}_2 \exp(-i\omega\tau + Q_2^{-1}/2)}, \quad (5)$$

where $\tilde{r}_1 = [\rho_2 \operatorname{Re}(\tilde{V}_2) - \rho_1 V_1(1 + iQ_2^{-1}/2)] / [\rho_2 \operatorname{Re}(\tilde{V}_2) + \rho_1 V_1(1 - iQ_2^{-1}/2)]$ and $\tilde{r}_2 = [\rho_3 V_3(1 - iQ_2^{-1}/2) - \rho_2 \operatorname{Re}(\tilde{V}_2)] / [\rho_3 V_3(1 - iQ_2^{-1}/2) + \rho_2 \operatorname{Re}(\tilde{V}_2)]$ are the normal-incidence acoustic reflection coefficients for the layer top and bottom, τ is two-way travel-time in the layer,

$$Q_2^{-1} = \operatorname{Im}(\tilde{V}_2^2) / \operatorname{Re}(\tilde{V}_2^2), \quad (6)$$

and

$$\tilde{V}_2 = \{[(Z_{0,2} + \tilde{Z}_{N,2})^{-1} + (4/3)\mu_2] / \rho_2\}^{1/2}. \quad (7)$$

Here ρ and V are rock density and P-wave velocity, tildes mark complex values, indices 1, 2, and 3 relate to rocks above, within, and below the layer, respectively, and $Z_{0,2}$ and μ_2 are compliance and

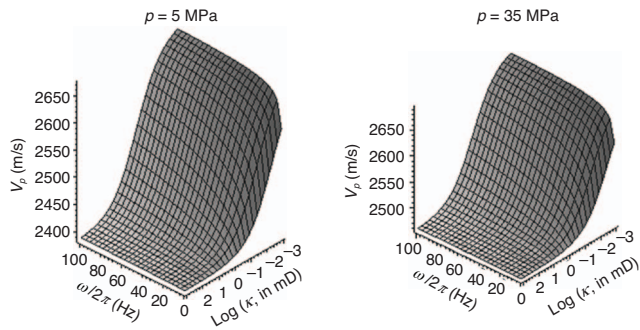


Figure 3. P-wave velocity in a permeable layer varies essentially with frequency at a moderate permeability of about 0.1–10 mD, but with permeability, the velocity varies most at moderate and low permeability $\kappa < 10$ mD. The increase of stress p decreases velocity-variation gradients but does not distort the $V_p(\omega, \kappa)$ function shape.

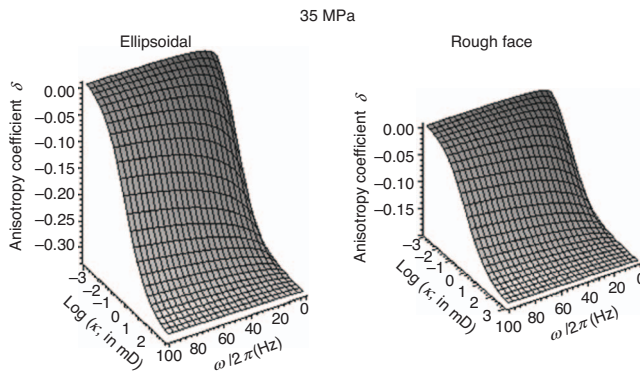


Figure 4. P-wave velocity anisotropy (Thomsen's coefficient δ) of rock with rough-face fractures is about the same as that of rock with ellipsoidal fractures at stress $p = 5$ MPa (not shown), but is 1.5 times less at $p = 35$ MPa. Neither fracture type nor stress p affects $\delta(\omega, \kappa)$ function shape.

shear modulus of the dry, isotropic reservoir host rock (i.e., with equant pores, but without fractures). The permeability-dependent, anisotropic reflection coefficient at oblique incidence can be roughly estimated by using approximate expressions derived in Appendix B; however, modeling the oblique incidence case is out of the scope of this paper.

The simplest noise-free model for a seismic trace in the frequency domain can be expressed as $S(\omega, \tau) = R(\omega, \tau)W(\omega)$, where $S(\omega, \tau)$, $R(\omega, \tau)$, and $W(\omega)$ are complex spectra of the trace, reflectivity function, and seismic wavelet, respectively. To model the seismic signal

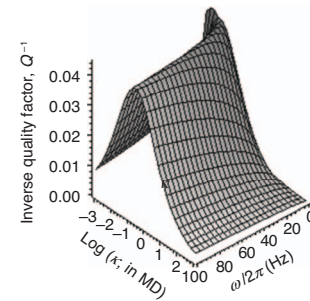


Figure 5. The intrinsic attenuation $Q^{-1}(\omega, \kappa)$ has a sharp maximum as a function of permeability (at about 1 mD for $\omega = 100$ Hz and at 0.01 mD for $\omega = 1$ Hz) but no distinct maximum as a function of frequency at $\kappa = \text{const}$. At very low permeability ($\kappa < 0.1$ mD), intrinsic attenuation decreases with increasing frequency. At moderate and high permeability ($\kappa > 1$ mD), intrinsic attenuation increases with increasing frequency. The maximum gradient is at about 10 mD.

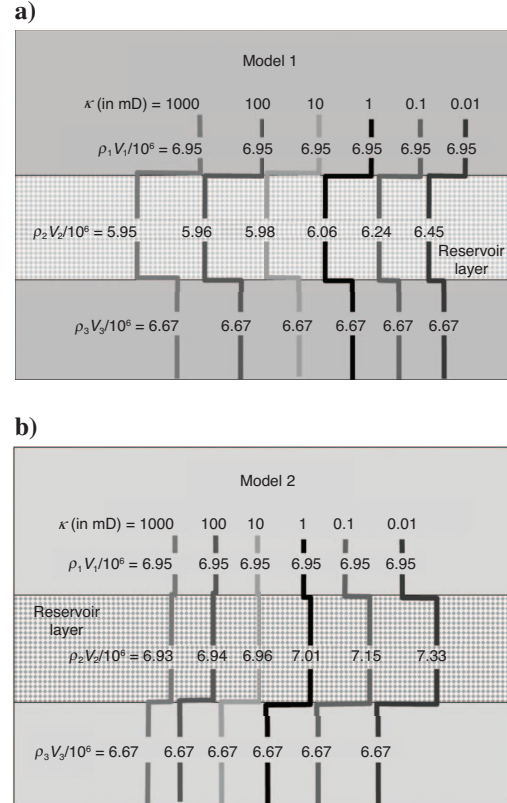


Figure 6. Parameters of a reservoir-layer model with acoustic impedance lower (a) and mainly higher (b) than in the enclosing seal rocks.

ture of permeability in an explicit form, the spectrum $S(\omega, \tau)$ must be split into three components. The first of them, designated $S_A(\omega, \tau)$, is defined as resulting from acoustic-impedance contrasts at no fluid flow (all voids are isolated, $\kappa = 0$, $F = 1$, so the reflectivity results only from layering). The second component is the Thomsen-style (i.e., elastic) contribution of fluid flow, which is defined as $S_C(\omega, \tau) = S_{CA}(\omega, \tau) - S_A(\omega, \tau)$, where $S_{CA}(\omega, \tau) = S(\omega, \tau)$ with Q^{-1} set to zero in equation 5. In other words, $S_C(\omega, \tau)$ results from the (elastic) extra compliance induced by fracture-and-pore connectivity. And finally, the third component, $S_Q(\omega, \tau) = S(\omega, \tau) - S_{CA}(\omega, \tau)$ results solely from the inelastic attenuation caused by the nonzero viscosity of the flowing fluid. Spectra of the full wavetrain and its three components are modeled by using the formalism represented by equations 2–7 for two different models of the reservoir layer. In the first model, an increase of the layer permeability leads to an increase of the layer acoustic-impedance contrasts with enclosing rocks (Figure 6a), whereas in the second model, the impedance contrasts decrease as the layer permeability increases (Figure 6b). Values of the layer and enclosing rock parameters used for modeling are shown in Table 1; $W(\omega)$ is represented by the spectrum of a 30-Hz Ricker wavelet.

Altogether, three series of 3D plots are calculated. To reduce the number of figures, only amplitude spectra are displayed. In the first series (Figures 7–10), plots of spectrum $|S(\omega, \tau)|$ and its components $|S_A(\omega, \tau)|$, $|S_C(\omega, \tau)|$, and $|S_Q(\omega, \tau)|$, are presented for three fixed values of permeability ($\kappa = 0.001$, 1, and 1000 mD) and with $p = 10$ MPa. The following observations are pertinent: (1) The reservoir-layer thickness (or, more precisely, the ratio of the layer temporal thickness τ to the wavelet apparent period T) affects the spectrum shape much more than does the permeability, frequency, or pore pressure. (2) For model 1, the spectrum $|S(\omega, \tau)|$ peak value and variability with τ/T increase with permeability, whereas for model 2, the opposite occurs (Figure 7). (3) As should be expected, the acoustic-impedance-contrast component S_A is not affected by permeability variations at all (Figure 8); the contribution of the extra compliance component S_C to the total spectrum of both of the models is more significant than the contribution of attenuation S_Q (cf. Figures 9 and 10). (4) Variation of permeability affects components S_C and S_Q in different ways. Indeed, the magnitude of S_C (the extra compliance component) is seen to monotonically increase tenfold as permeability increases from 0.001 mD to 1 D (Figure 9), whereas the magnitude of S_Q (the attenuation component) increases only slightly as permeability increases from 0.001 to 1 mD and then decreases more than tenfold with further increase of permeability from 1 mD to 1 D.

The second and third series (Figures 11–16) are created to illustrate the performance of two seismic attributes introduced to track lateral variations of permeability in the reservoir rock. Both attributes are calculated by using the kind of spectral decomposition described in Mushin et al. (2000). One of the attributes (Davydova et

Table 1. Values of parameters used for modeling.

$K = 9$ GPa (1st model)	$K_f = 2.2$ GPa	$\phi = 0.2$	$V_{p1} = 3021$ m/s
$\mu = 9$ GPa (1st model)	$\eta_f = 0.001$ Pa s	$\nu = 0.25$	$V_{p3} = 2900$ m/s
$K = 12.4$ GPa (2nd model)	$e = 0.1$	$\nu_s = 0.125$	$\rho_1 = 2300$ kg/m ³
$\mu = 12.4$ GPa (2nd model)	$c = 4$		$\rho_3 = 2300$ kg/m ³
$K_s = 40$ GPa	$b = 0.0001$		$\rho_2 = 2650$ kg/m ³

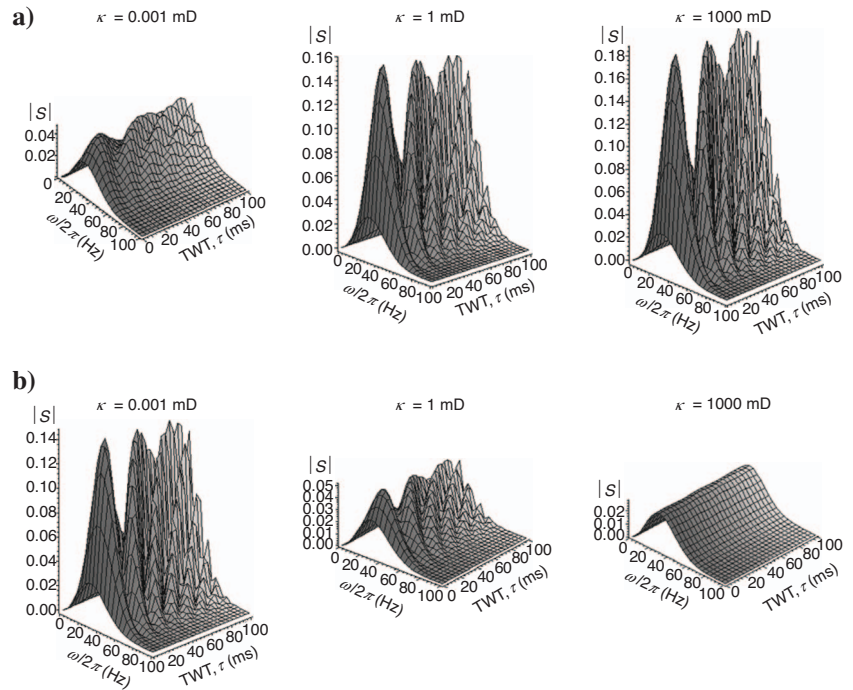


Figure 7. Modulus $|S|$ of reflected-wavetrain spectra as a function of frequency ω and reservoir-layer thickness τ (in TWT = two-way traveltime), at permeability $\kappa = 0.001$, 1, and 1000 mD, for the (a) first and (b) second models. The $|S|$ function has a complex shape, rather stable in κ and mostly affected by variations of τ . Modulus $|S|$ magnitude increases with κ for the first model and decreases with κ for the second model.

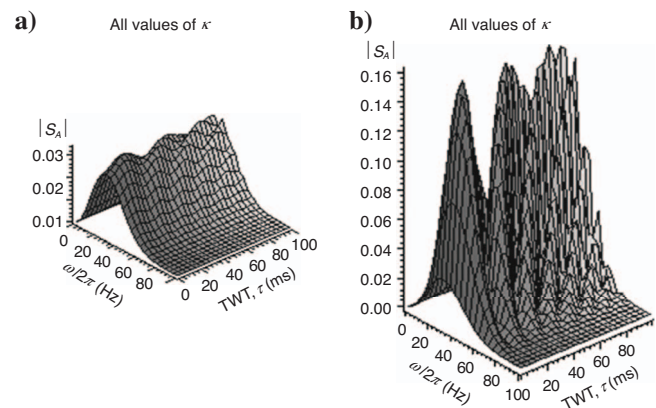


Figure 8. Modulus $|S_A|$ of the acoustic-impedance component of reflected wavetrain spectra as a function of frequency ω and reservoir-layer thickness τ (in TWT = two-way traveltime), at permeability $\kappa = 0.001$, 1, and 1000 mD, for the (a) first and (b) second models. As expected, the component $|S_A|$ is independent of permeability. The $|S_A|$ function magnitude for the first model is about five times smaller than that of the second model.

al., 2005) maps the ratio of the high-frequency part of the amplitude spectrum $|F(\omega, t)|$ of a seismic trace $f(t) = s(t) + n(t)$ to the low-frequency part of $|F(\omega, t)|$:

$$K1 = \left(\sum_{\omega_m}^{\omega_2} |\bar{F}(\omega, \tau)| \right) / \left(\sum_{\omega_1}^{\omega_m} |\bar{F}(\omega, \tau)| \right). \quad (8)$$

Here t is recording time, $n(t)$ is additive noise, ω_1 and ω_2 define the low and high limits of frequency range, and ω_m is an arbitrarily chosen value near the spectrum maximum. The bar over F in equation 8 means averaging within the target time interval. Performance of this attribute for the noiseless trace ($F = S$) is illustrated by the second series of plots (Figures 11 and 12).

Another attribute makes use of the first derivative (with respect to frequency) of the low-frequency slope of the current spectrum $|F(\omega, t)|$ (Lichman and Goloshubin, 2003). The potential predictive power of this attribute is illustrated in the third series of plots mapping the noiseless value of $\partial|S(\omega, \tau)|/\partial\omega \equiv |S'|$ at 15 Hz (Figures 13 and 14). The important practical message of the second and third se-

ries of plots is that both K_1 and $|S'|$ attributes are much more affected by the τ/T ratio than by permeability. Depending on the ratio τ/T , both K_1 and $|S'|$ values can either increase or decrease with increasing permeability (Figures 11–14). Indeed, for the first model, the K_1 attribute increases with increasing permeability at $\tau/T = 0.25 \pm 0.25, 1.25 \pm 0.25, 2.25 \pm 0.25, \dots$, and decreases with increasing permeability at $\tau/T = 0.75 \pm 0.25, 1.75 \pm 0.25, 2.75 \pm 0.25, \dots$ (Figure 11a). On the contrary, for the second model, the K_1 attribute decreases with increasing permeability at $\tau/T = 0.25 \pm 0.25, 1.25 \pm 0.25, 2.25 \pm 0.25, \dots$, and increases with increasing permeability at $\tau/T = 0.75 \pm 0.25, 1.75 \pm 0.25, 2.75 \pm 0.25, \dots$ (Figure 11b). The maximum gradient of the K_1 variation with increasing permeability shows up at $0.1 \text{ mD} < \kappa < 10 \text{ mD}$, i.e., the attribute K_1 is expected to work best at low and moderate permeability.

For the first model, the values of the $|S'|$ attribute increase with increasing permeability at $\tau/T = 0.75 \pm 0.5, 2.75 \pm 0.5, \dots$, and decrease with increasing permeability at $\tau/T = 1.75 \pm 0.5, 3.75 \pm 0.5, \dots$ (Figure 13a). For the second model, the

Figure 9. Modulus $|S_C|$ of the reflection-spectra component attributable to (elastic) extra compliance caused by fluid mobility, as a function of frequency ω and reservoir-layer thickness τ (in TWT = two-way traveltime), at permeability $\kappa = 0.001, 1$, and 1000 mD , for the (a) first and (b) second models. The component $|S_C|$ magnitude increases with increasing permeability for both the first and second models.

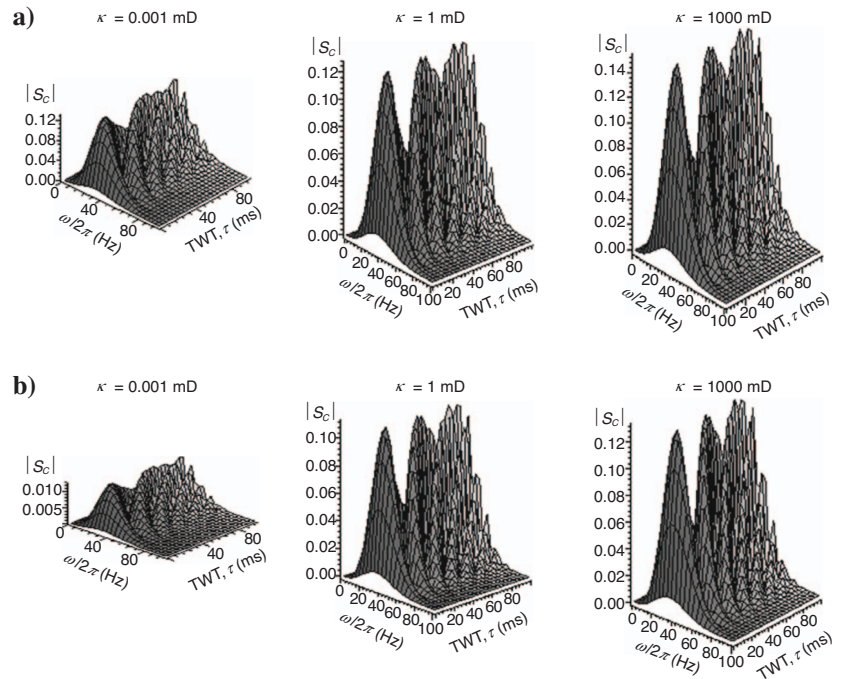
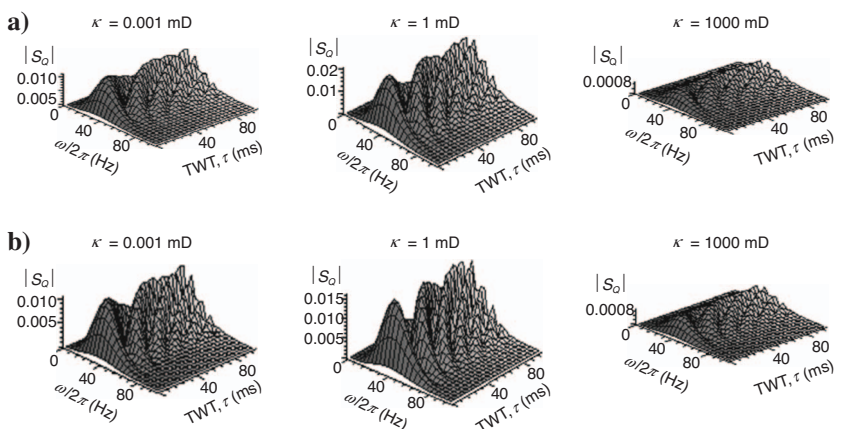


Figure 10. Modulus $|S_O|$ of the reflected spectra component attributable to inelastic attenuation caused by fluid mobility, as a function of frequency ω and reservoir-layer thickness τ (in TWT = two-way traveltime), at permeability $\kappa = 0.001, 1$, and 1000 mD , for the (a) first and (b) second models. For both the models, $|S_O|_{\kappa=0.001 \text{ mD}} < |S_O|_{\kappa=1 \text{ mD}}$ and $|S_O|_{\kappa=1 \text{ mD}} > |S_O|_{\kappa=1000 \text{ mD}}$, which is consistent with Figure 6.



$|S|'$ values decrease with increasing permeability at $\tau/T = 0.75 \pm 0.5, 2.75 \pm 0.5, \dots$, and increase with increasing permeability at $\tau/T = 1.75 \pm 0.5, 3.75 \pm 0.5, \dots$, Figure 13b. The range of maximum gradient of $|S|'$ variation with permeability is $0 < \kappa < 1$ mD, i.e., attribute $|S|'$ is expected to work best at very low permeability.

Finally, to see how pore-pressure variations can affect the layer spectrum response to permeability changes, one more series of plots mapping the function $|S(p, \tau)|$ for $\kappa = 1$ mD and $\omega/2\pi = 30$ Hz is calculated (Figures 15 and 16). Spectrum $|S(\omega, \tau)|$ and its components $|S_A(\omega, \tau)|$, $|S_C(\omega, \tau)|$, and $|S_Q(\omega, \tau)|$ at different effective stresses (p) are seen to scale down as p increases (pore pressure decreases). The effect of pore-pressure variations is especially significant at low contrasts in acoustic impedance. The shape of the function $|S(p, \tau)|$ is most affected by the ratio τ/T .

Note that sometimes, values and/or shapes of component moduli $|S_A(\omega, \tau)|$ or $|S_C(\omega, \tau)|$ are seemingly inconsistent with value and/or shape of modulus $|S(\omega, \tau)|$ of the total trace spectrum (cf. Figures 11 with 12 and 13 with 14). This peculiarity stems from the fact that $S(\omega, \tau)$ is represented by the algebraic sum of spectral components $S_A(\omega, \tau)$, $S_C(\omega, \tau)$, and $S_Q(\omega, \tau)$, which is not the same as the sum of the component moduli.

FIELD DATA

As follows from the modeling results, examples from Pisetski (1995) and Lichman and Goloshubin (2003), mentioned in the introduction, actually do not contradict each other. Furthermore, numerous examples of 3D data interpretation based on implementation of a set of K_1 -like attributes (Davydova et al., 2005; Afanasiev, 2006; Baransky et al., 2006) allow one to generate some statistics. Of the 17 data sets interpreted, six demonstrate a distinct increase of high-frequency content with increasing permeability (group A fields, Baransky et al., 2006) (e.g., Figures 17 and 19), and 11 data sets show the opposite trend (group B fields, Baransky et al., 2006) (Figure 18a). The majority of the data sets considered in these publications were acquired in West Siberia, but some of them came from the Timan-Pechora basin and East Siberia. The numerical values of parameters ω_1 , ω_2 , and ω_m in equation 8 were chosen individually for each particular data set so as to ensure a maximum correlation coefficient between (1) the attribute values calculated for synthetic or real seismic traces at the well sites within the data-set area and (2) the effective permeability estimates derived from the respective well logs or tests. The correlation coefficients observed at different areas for different targets vary from 0.6 to 0.9 and average about 0.8. The reliability of the predictions is confirmed by subsequent drilling (Afanasiev, 2006). Note that the K_1 -like attributes also show rather strong correlation with effective porosity and oil productivity estimated by well tests. Because effective connected porosity, permeability, and hydrocarbon productivity are commonly well correlated with each other, one could have assumed that good correlation of the attribute with permeability is caused by intrinsic correlation of the attribute with porosity, so the

correlation with permeability comes as a sec-ondary effect. However, such an assumption does not seem true in most cases, because the attribute correlation with permeability proves to be at least as high as with porosity (e.g., Figure 18a and b). A crossplot of the K_1 attribute with all well data (including wells without sonic logs) yields lower, but still reliable correlation (Figure 19).

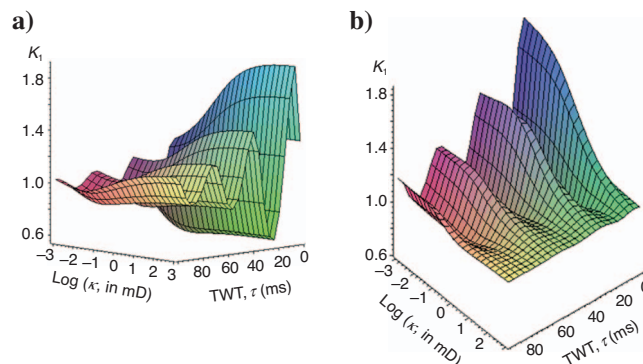


Figure 11. Attribute K_1 as a function of permeability κ and layer thickness τ (in TWT = two-way traveltime), for the (a) first and (b) second models. Either an increase or decrease of the K_1 value with increasing permeability is possible, depending on the layer thickness. The range of the K_1 variation with layer thickness increases with increasing permeability for the first model and decreases with increasing permeability for the second model.

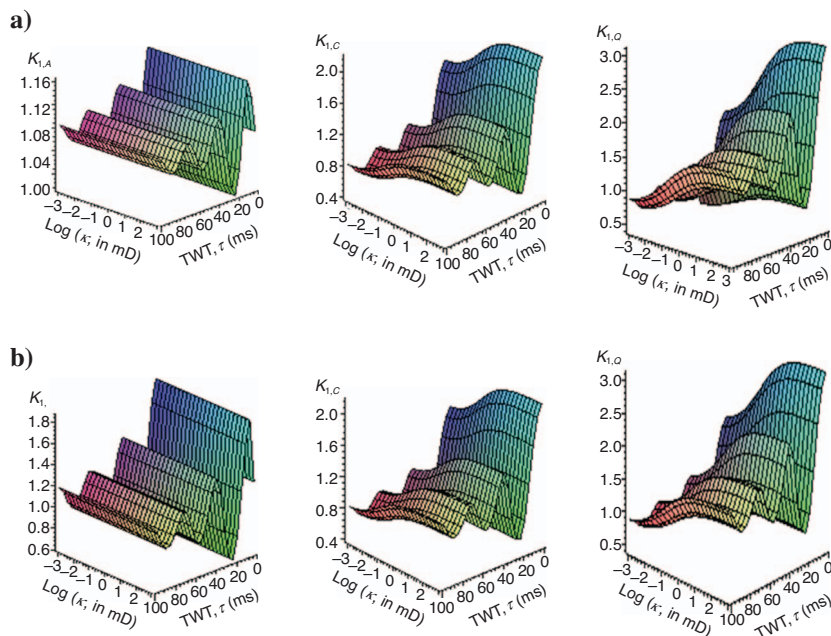


Figure 12. Attribute K_1 calculated for separate components S_A , S_C , and S_Q , as a function of permeability κ and layer thickness τ (in TWT = two-way traveltime) for the (a) first and (b) second models. Attribute K_1 of the S_A component does not vary with permeability, whereas attributes K_1 of S_C and S_Q components strongly depend on permeability. Increase of the K_1 magnitude with increasing permeability, which is especially strong for the S_Q component, prevails for all layer thicknesses and for both of the models. Note that the K_1 values are calculated separately for the components, so the actual contribution of each component to the algebraic summation of complex values is not described by the figure.

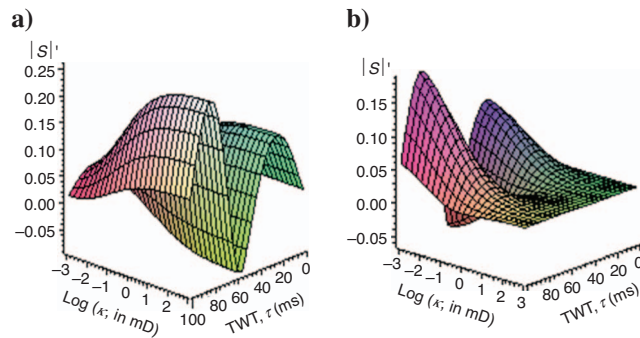


Figure 13. Attribute $|S'|$ calculated at $\omega/(2\pi) = 15$ Hz as a function of permeability κ and layer thickness τ (in TWT = two-way traveltime). (a) For the first model, either an increase or a decrease of the attribute with increasing permeability is possible, depending on the layer thickness. (b) For the second model, decrease of the attribute with increasing permeability prevails.

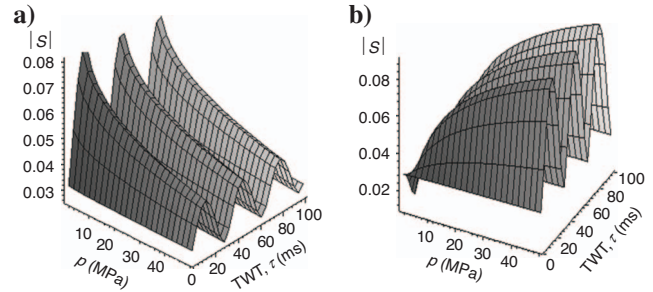


Figure 15. Modulus $|S|$ of the reflected wavetrain spectrum as a function of stress p and reservoir-layer thickness τ (in TWT = two-way traveltime) at permeability $\kappa = 0.01$ and frequency $\omega/(2\pi) = 30$ Hz for the (a) first and (b) second models. The spectrum values at this frequency are seen to mainly decrease with stress for the first model and increase with stress for the second model.

DISCUSSION

Seismic attributes designed to serve as indicators of permeability are based on peculiarities of the reflected-wavetrain amplitude spectra caused by pore-fluid mobility. Originally, these attributes were derived by considering reflection from a single boundary that divided a permeable half-space from an impermeable one. For such a case, the fluid mobility is indeed the only source of the frequency dependence of the boundary reflection coefficient.

However, in the environment of thin, alternating permeable and impermeable layers, the permeability attributes become ambiguous because the frequency dependence of the wavetrain-reflectivity function is strongly affected by layering. Indeed, the modeling results just demonstrated have shown that even in the case of a single permeable layer within impermeable rock, the permeability attributes can be either directly or inversely proportional to frequency, depending on the ratio of permeable-layer thickness to the dominating wavelength. The difference in the coefficients of proportionality is rather significant (Figures 11 and 13), so it may manifest itself in the presence of noise of a moderate level. The modeling results are consistent with field data.

The problem is similar to the one recognized many years ago as thin-layer amplitude-variation-with-angle/offset (AVO): the well-known subdivision of AVO anomalies onto four classes, defined for single boundaries, appears to be ambiguous in the case of thin-layer reservoirs. To circumvent this difficulty, the fluid-substitution technique was introduced to support AVO analysis, and now this technique is one of the cornerstones of AVO inversion. Probably, designing a modeling technique that can be called permeabil-

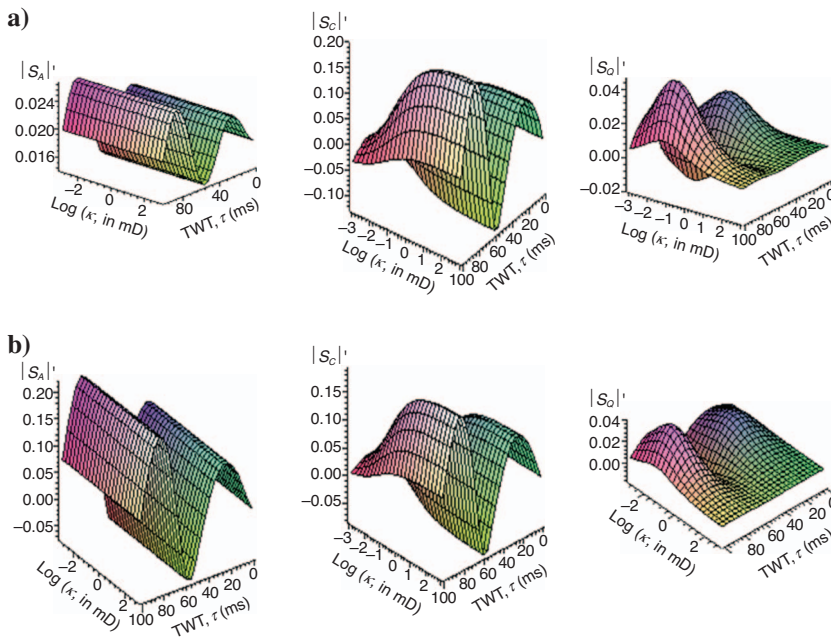


Figure 14. Attribute $|S'|$ calculated at frequency $\omega/(2\pi) = 15$ Hz for separate components S_A , S_C , and S_O , as a function of permeability κ and layer thickness τ (in TWT = two-way traveltime), for the (a) first and (b) second models. Attribute $|S_A|$ of the S_A component does not vary with permeability, whereas attributes $|S_C|$ and $|S_O|$ strongly depend on permeability. Of these two attributes, $|S_C|$ strongly dominates in magnitude. Note that the derivative values are calculated separately for the components, so the actual contribution of each component to the algebraic summation of complex values is not described by the figure.

ity substitution would be of help in interpreting cubes of permeability attributes as well. In the cases of stable state of stress, effective models developed by Thomsen (1995), Hudson et al. (1996), and Hudson et al. (2001) can be adequate springboards for elaboration of such a modeling technique. However, for environments where

effective-stress variations are possible (e.g., 4D seismic), the rough-face-fracture formalism seems to be preferable because it reflects explicitly the effective-stress dependence and covers seamlessly the whole range of dual-porosity rock types, from purely porous to purely fractured ones.

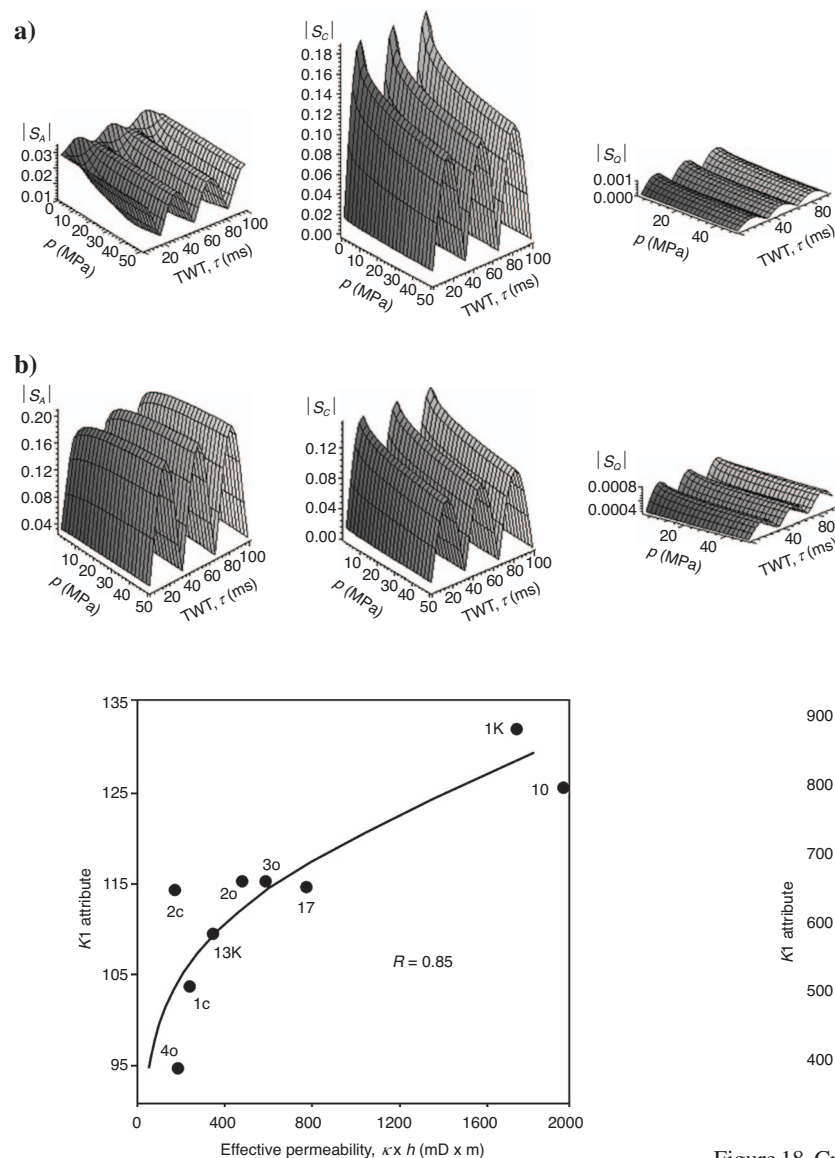


Figure 17. Crossplot of the attribute K_1 versus effective permeability $\kappa \times h$ for the group A field, West Siberia (Baransky et al., 2006). Here, h is net pay thickness, and κ is average permeability of rocks constituting the net pay. The attribute K_1 is seen to increase with increasing effective permeability. Note the good correlation between real (wells, labeled by each data point) and predicted (K_1 -derived) values. Note also the full consistency of the approximating line with the moderate-to-low-permeability estimate for well 17 that was drilled after interpretation. Wells with sonic logs are used. (Courtesy of E. Davydova, personal communications, 2004.)

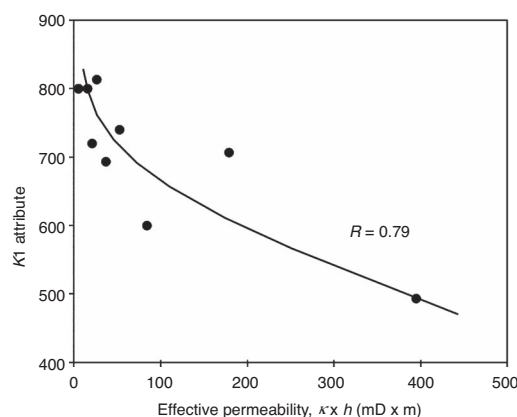


Figure 18. Crossplot of the attribute K_1 versus effective permeability $\kappa \times h$ for the group B field, West Siberia (Baransky et al., 2006). K_1 is decreasing with the increase of effective permeability here. Wells with sonic logs are used. (Borrowed from Afanasiev, 2006.)

will be, however, very cumbersome. A rough, but very simple approximation can be proposed for the two-term AVO formula

$$R(\theta) = R_0 - G \sin^2 \theta, \quad G = 4 \frac{V_S^2}{V_P^2} \left(\frac{\Delta V_S}{V_S} + \frac{1}{2} \frac{\Delta \rho}{\rho} \right). \quad (\text{B-1})$$

The intercept R_0 is defined as either $\tilde{r}_1$ or $\tilde{r}_2$, depending on whether the top or the bottom of the permeable layer is considered to be the reflector. The only factor of the AVO gradient G dependent on fluid mobility here is $1/V_P^4 \equiv 4/(V_{m-1} + V_m)^2$, where $m = 1, 2$ are indices of media above and below the reflector. Setting the m th layer to be permeable and $(m - 1)$ th layer to be impermeable, velocity $V_m \equiv \tilde{V}_m$ can be expressed via quantity $\tilde{V}^2$ (defined by equation 6) as

$$\tilde{V}_m \equiv \sqrt{\tilde{V}^2} = \sqrt{\text{Re}(\tilde{V}^2) + i \text{Im}(\tilde{V}^2)} = \sqrt{\text{Re}(\tilde{V}^2)[1 + iQ^{-1}]}. \quad (\text{B-2})$$

Note that in the case of oblique incidence on an HTI layer, both $\tilde{V}^2$ and Q^{-1} are dependent on the incidence angle θ and the azimuthal angle ψ , defined with respect to the HTI axis of symmetry, so expression 6 should be replaced with the following equation (e.g., Chichinina et al., 2006):

$$\tilde{V}^2(\theta, \psi) = V_{P_0}^2 \{1 - \tilde{\Delta}_N [1 - 2g \sin^2 \varphi]^2 - \Delta_T g \sin^2 2\varphi\}, \quad (\text{B-3})$$

where $g = V_{S_0}^2/V_{P_0}^2$ and $\sin^2 \varphi = 1 - \sin^2 \theta \cos^2 \psi$. Here $\tilde{\Delta}_N$ and Δ_T are defined in the main text, and V_{P_0} and V_{S_0} are vertical velocities in a dry unfractured medium.

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