A SIMPLE TECHNIQUE FOR ESTIMATION OF RESERVOIR PERMEABILITY FROM SEISMIC REFLECTION DATA BASED ON BIOT'S THEOREM

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Abstract

Relationships among elastic parameters and rock properties, and ultimate reservoir parameters have been established in continuum mechanics and rock physics. Therefore, it should be possible to estimate reservoir permeability from the seismic data. We used Biot's solution of wave equation in an elastic porous medium and the approximations of Turgut-Yamamoto to allow an establishment of a linear relationship between attenuation coefficient or amplitude ratio as a function of the inverse of frequency. The slope of this function includes the permeability. It can be shown that this technique agrees to the measurement of the permeability of a porous medium from seismic waveforms. We examined this technique to estimate the reservoir permeability by using synthetic seismograms data. The result show that an error less than 5%, it means that the study of permeability estimation from surface seismic data is possible by using an accurate calibration step.

The procedure is tested on 3D seismic data over part of Dun field in central Sumatra, Indonesia. The simplicity of the theoretical approach requires the introduction of an empirical calibration factor that is provided by well data in the area. This factor is then implemented to estimate the permeability with seismic data on the field, it gives a permeability map of the study area. A key result of the study is that permeability estimation with surface seismic data are possible but requires calibration. A confirmation and validation of this procedure will be subject to future work.

1. Introduction

Reservoir characterization is one of the advanced steps in seismic exploration to identify physical properties of reservoir such as thickness, porosity, permeability, density, compressibility, and water saturation. These physical properties are used to model the fluid flow in a producing well. We use two geophysical methods for example, NMR log tomography, generally attempt to directly estimate the reservoir physical properties from the seismic data. Horizontal and vertical seismic probing using synthetic seismograms, which include the absorption effect of the reservoir, especially for permeability, has been constructed by Sismanto et al. (2003a). The Synthetic techniques are to obtain the Turgut-Yamamoto (1988) and Garney (1981) mechanism. Turgut and Yamamoto (1988) accessed the possibility of producing porosity and permeability of marine sediments by analysing phase velocity dispersion and attenuation of the least compressional waves as a function of frequency where most theoretical and experimental researches prove that there is a close relationship among waves, elastic, and poroelastic parameters. This relationship also agrees with the field data of Munadi et al. (1998); Sarar and Mangi, 1999. Thus, the reservoir parameters are believed to affect elastic wave characters. With this type of wave, reservoir parameters such as porosity and permeability should therefore be able to be theoretically obtained from the seismic data.

2. Fundamental

Two basic equations describing the relationship between the attenuation and shear waves in a fluid-saturated porous (unconsolidated) isotropic and elastic media such as marine sediments, are (Bird 1956):

\[ \frac{s^2 - 1}{s} \frac{\nu_s^2}{\nu_s^2 - 1} = \rho_s \frac{K_s}{\rho_w} \frac{1 - 2v_s}{1 + 2v_s} \nu_s^2 \]

where:

- \( s \) = any frequency
- \( \nu_s \) = phase velocity of shear waves
- \( K_s \) = bulk modulus of sediments
- \( \rho_s \) = density of sediments
- \( \rho_w \) = density of water
- \( v_s \) = Poisson's ratio of sediments

and

\[ \frac{s^2 - 1}{s} \frac{\nu_s^2}{\nu_s^2 - 1} = \rho_s \frac{K_s}{\rho_w} \frac{1 - 2v_s}{1 + 2v_s} \nu_s^2 \]

According to Turgut and Yamamoto (1990), the bulk modulus of sediments, \( K_s \), and the porosity, \( \phi \), are related to the elastic modulus as:

\[ \frac{K_s}{\rho_s} = \frac{1}{1 - 2v_s} \frac{1}{\nu_s^2} \frac{1}{\phi} \]

3. Methodology

To estimate the permeability, we need a seismic waveform velocity and its spectral analysis of the events. The bulk modulus of fluid, \( K_f \), to be defined previously. According to Garney, (1981) and Smit, (1981) indication for marine sediments with High F.Eq. (1) and (2) can be obtained in the following form:

\[ s^2 - 1 \]

\[ \frac{\nu_s^2}{\nu_s^2 - 1} \]

\[ \frac{\nu_s^2}{\nu_s^2 - 1} \]

From the slope, \( n \), we can estimate the permeability: i.e.

\[ \frac{\nu_s^2}{\nu_s^2 - 1} \]

where \( n \), and \( m \) are the amplitude of signal at the + and - positions in the frequency domain respectively. By solving Eq. (1) and Eq. (2), the permeability of the medium, \( \phi \), can be written as:

\[ \phi = \frac{K_s}{\rho_s} \frac{1}{1 - 2v_s} \frac{1}{\nu_s^2} \frac{1}{\phi} \]

The curve of Eq. (1) is linear between \( \nu_s^2 \) and \( n \) (amplitude ratio at logarithmic). If the slope is 1, we can determine the permeability of the medium, i.e.

\[ \phi = \frac{K_s}{\rho_s} \frac{1}{1 - 2v_s} \frac{1}{\nu_s^2} \frac{1}{\phi} \]

4. Synthetic Seismograms

The synthetic seismograms cover reservoir parameters, elastic parameter, and wave parameters based on Garney (1981). The permeability of the model depends on those parameters is given by Smit and Smit (1981).

5. Examples of Numerical Result

6. Field Examples

Examples of the seismograms confirm that the model is working. An example of real data from the Dun field is shown below. The model is working for the new model as well.

7. Conclusions

For testing the seismograms with acceptable approximations a linear relationship between the absorption coefficient and the inverse square of the frequency has an error less than 5%. However, a key result of the study suggests that permeability estimation with surface seismic data is possible through its accurate calibration.

The application of the methods to the surface seismic reflection CDP data on the 3D seismic in a small Dun field area, central Sumatra is being studied. An important step is to develop an empirical calibration factor. The calibration step is an important stage, and it needs more studies (testing) data that vary in velocity, frequency, and anisotropy.

Acknowledgments

We gratefully acknowledge the Geophysical Institute, Karlsruhe, Germany for providing facilities during the research. The DURST project of the Geophysics Study Program, Gadjah Mada University, for financial support, and the invaluable support of P.T. CITI especially the following collaborators for their help: Mr. Markha, Mr. E.B. Kurniawan, Mr. Supriadi, Mr. Maryanto, and E.S. Iman in Rambu.
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Abstract

Relationships among elastic parameters and rock properties, and ultimate reservoir parameters have been established in continuum mechanics and rock physics. Therefore, it should be possible to estimate reservoir permeability from the seismic data. We used Biot's solution of wave equation in an elastic porous medium and the approximations of Turgut-Yamamoto to allow an establishment of a linear relationship between attenuation coefficient or amplitude ratio as a function of the inverse of the square of frequency. The slope of this function includes the permeability. It can be shown that this technique agrees to the measurement of the permeability of a porous medium from seismic waveforms. We examined this technique to estimate the reservoir permeability by using synthetic seismogram data. The result show that has an error less than 5 %, it means that the study of permeability estimation from surface seismic data is possible by using an accurate calibration step.

The procedure is tested on 3D seismic data over part of Duri field in central Sumatra, Indonesia. The simplicity of the theoretical approach requires the introduction of an empirical calibration factor that is provided by well SM#A in the area. This factor is then implemented to estimate the permeability with seismic data on the field; it gives a permeability map of the study area. A key result of the study is that permeability estimation with surface seismic data are possible but requires calibration. A confirmation and validation of this procedure will be subject to future work.

Keywords: Seismic wave, permeability, Biot, Turgut-Yamamoto.
1. Introduction

Reservoir characterization is one of the advanced steps in seismic exploration to identify physical properties of a reservoir such as thickness, porosity, permeability, density, compressibility, and water saturation. These physical properties are used to model the fluid flow in a producing field. Recent new geophysical methods for example, AVO and tomography, generally attempt to directly estimate the reservoir physical properties from the seismic data. Turgut and Yamamoto (1988) developed a one-dimensional (1D) model of VSP, which includes mode conversion through slow compressional waves as an energy loss mechanism based on Ganley (1981). Horizontal and vertical seismic profiling synthetic seismograms which include the absorption effect of the reservoir, especially for permeability, has been constructed by Sismanto, et al. (2003a). The Sismanto’s technique is to combine the Turgut-Yamamoto and Ganley mechanism. Turgut and Yamamoto (1988; 1990) explored the possibility of predicting porosity and permeability of marine sediment by analyzing phase velocity dispersion and attenuation of the fast compressional waves as a function of frequency. Meanwhile, most theoretical and experimental researches prove that there is a close relationship among waves, elastics, and reservoir parameters. This relationship also agrees with the field data (Munadi, 1998; Saar and Manga, 1999). Thus, the reservoir parameters are believed to affect seismic wave characters. With this point of view, reservoir parameters, such as porosity and permeability should therefore, are able to be theoretically obtained from the seismic data.

Sismanto, et al. (2003b) developed a technique to estimate the permeability on the seismogram synthetic based on Turgut-Yamamoto equation, but the relationship of the permeability estimation to the permeability model is still multifaceted. Furthermore, Sismanto et al., (2005a) published a simple technique to estimate the permeability on the real 3D seismic data based on Turgut-Yamamoto equation as well. The Turgut-Yamamoto equation was modified to expand a linear relationship between the attenuation coefficient and the amplitude ratio as a function of frequency, but there are still many problems were ignored.

The aim of this paper is to examine the Sismanto et. al. (2005a)’s method to estimate reservoir permeability from the synthetic seismic reflection data. Consequently, we can minimize the real problem in order to get the accuracy of the technique.

2. Fundamental

Two basic equations describing the relationship between dilatational and shear waves in a fluid-saturated porous (unconsolidated) isotropic and elastic media such as marine sediments, are (Biot, 1956)

$$\mu \nabla \cdot (\nabla - \mu \nabla \theta - C \nabla \zeta_r) = \rho \frac{\partial^2 u}{\partial t^2} - \rho_f \frac{\partial^2 \tilde{v}}{\partial t^2}$$ (1)

$$C \nabla \theta - M \nabla \zeta_r \rho_f \frac{\partial^2 \tilde{V}}{\partial t^2} - \eta \frac{\partial \tilde{V}}{\partial t}$$ (2)

in which $u$ is the frame displacement vector, $\tilde{v}$ is the seepage displacement vector, $\theta = \text{div} \ u$, $\zeta_r = \text{div} \ \tilde{v}$, $\rho$ is the bulk density ($\rho = (1-\phi) \rho_f + \phi \rho_s$), $\rho_f$ is the density of fluid, $\phi$ is the porosity, $\eta$ is the viscosity of fluid, and $k_p$ is the coefficient of the permeability. $H$, $C$, and $M$ are the Biot’s elastic moduli, $\mu$ is the shear modulus, and $m$ is the virtual mass expressed as $m = \alpha \rho_f/\phi$, with $\alpha = 1.25$ (Turgut and Yamamoto, 1990). The Biot’s elastic moduli are expressed by the following relations

$$H = (K_s - K_r)$$

$$C = \frac{K_s (K_s - K_r)}{D_s - K_r}, \quad M = \frac{K_s^2}{D_s - K_r},$$

and

$$D_r = K_s \left[ 1 + \phi \left( \frac{K_s}{K_f} - 1 \right) \right].$$ (3)

...
where $K_s$ is the bulk modulus of the grain, $K_f$ is the bulk modulus of the fluid in the pores, and $K_b$ is the bulk modulus of the skeletal frame. According to Turgut and Yamamoto (1990), the bulk modulus of skeletal frame $K_s$ and the porosity are related to the shear modulus as

$$ K_s = \left( \frac{2\sigma}{1-2\sigma} + \frac{\mu}{3} \right) \mu, \quad \text{and} \quad \phi = \frac{K_f(K_p-K_f)}{(K_r-K_f)(K-K_b)}. \quad (4) $$

where the shear modulus $\mu$, the Poisson's ratio $\sigma$ and the bulk modulus $K$ are estimated from the velocities of the P and S waves, where their relationships are given by

$$ \mu = \rho V_s^2, \quad \sigma = \frac{3K-2\mu}{2(3K+\mu)}, \quad \text{and} \quad K = \rho \left( V_p^2 - \frac{4}{3} V_s^2 \right). \quad (5) $$

3. Methods

To estimate the permeability, we need a seismic waveform velocity and its spectral analysis of the events. The bulk modulus of grain $K_s$, the density $\rho$ and the bulk modulus of fluid $K_f$ have to be defined previously. According to Turgut-Yamamoto (1990) approximation and Geertsma and Smit (1961) indication for marine sediment with high $Q$ Eqs. (1) and (2) can be obtained in the following form,

$$ Q^{-1} = \left( \frac{V_\infty^2}{V_0^2} - 1 \right) \frac{q_i + A}{q_i}, \quad (6) $$

where $q_i = \eta/k_p\omega$ is the imaginary part of $\hat{q}$, and $A = (\rho m - \rho_f^2)/\rho$. Whereas,

$$ V_0^2 = \frac{H}{\rho} \text{ for } \omega \to 0, \quad \text{and} \quad V_\infty^2 = \left( \frac{Hm + M\rho - 2C\rho_f}{\rho m - \rho_f^2} \right) \text{ for } \omega \to \infty. \quad (7) $$

Then, it can be found the location of the relaxation frequency (maximum attenuation) in a $(Q^{-1}, f)$ curve as

$$ f_r = \frac{\rho \eta}{2\pi \left( \rho m - \rho_f^2 \right) k_p} \left( \frac{V_\infty}{V_0} \right). \quad (8) $$

By using the relaxation frequency, the permeability coefficient can be estimated, if the other parameters have been determined. However, it is rather difficult to get a good curve of $(Q^{-1}, f)$ relationship for real data. Sismanto, et al., (2005a) modified the relationship of $(Q^{-1}, f)$ into a linear form.

Eq. (6) can be rewritten as

$$ Q = \frac{\omega}{2V_f \alpha(\omega)} \quad (9) $$

where $w = V_\infty^2/V_0^2$. According to the spectral ratio method for estimating $Q$ in laboratory, the definition of the quality factor $Q$ is,

$$ Q = \frac{\omega}{2V_f \alpha(\omega)}. \quad (10) $$

By combining Eqs. (9) and (10), ones obtains

$$ \frac{x2V_f}{\omega^2(W-1)} + \frac{W2V_f}{x(W-1)} = \frac{1}{\alpha(\omega)} \quad (11) $$

in which $x = \eta\rho/(k_p(\rho m - \rho_f^2))$. The relationship of $\alpha(\omega)$ and the frequency in Eq. (11) is asymptotic for high frequency region ($\omega \gg$). Unfortunately, we are not interested in the high frequency region and in practice it is difficult to obtain the asymptotic value because the frequency content of the seismic data is less then 200 Hz. While, the relationship between $[1/\alpha^2]$ and $[1/\alpha(\omega)]$ is linear for all frequency. However, the linear relationship of the data just takes place only in the frequency content of the signal.

From the slope $\gamma$, we can estimate the permeability, i.e.,

$$ k_p = \frac{2V_f \rho \eta}{\gamma(\rho m - \rho_f^2)(W-1)^2}. \quad (12) $$

It is obvious that the coefficient of attenuation $\alpha(\omega)$ can be calculated from the spectral ratio method by
\[ \alpha(\omega) = \ln \left( \frac{A_n(\omega)}{A_l(\omega)} \right) d^{-1}, \quad (13) \]

where \( A_n \) and \( A_l \) are the amplitude of signal at the \( n \) and \( l \) positions in the frequency domain respectively. In vertical seismic measurement (VSP), \( d \) is the distance between receivers in positions \( l \) and \( n \). In the reflection measurement \( d \) is the path difference of the recorded seismic wave at the surface.

Substituting Eq.(13) into Eq.(11), we will obtain

\[ \frac{2V_p}{d(W-1)} \left( \frac{x}{W} + \frac{W}{x} \right) = \left[ \ln \left( \frac{A_n(\omega)}{A_l(\omega)} \right) \right]^{-1}. \quad (14) \]

The curve of Eq. (14) is asymptotic for high frequency (\( \omega \rightarrow \infty \)) and linear between \( (1/\omega^2) \) and \( (1/\omega) \) amplitude ratio in logarithmic. If the slope is \( \tau \), we can determine the permeability of the medium, i.e.,

\[ k_p = \frac{2V_p \eta \rho}{d \tau (\rho_m - \rho_f^2)(W-1)}. \quad (15) \]

The forms of Eq.(14) and Eq.(11) are similar. The main difference is in the data. Eq. (11) needs more good seismic traces to calculate the attenuation coefficient, but using Eq. (14) we need only at least two traces of seismic data in CDP gather.

4. Synthetic seismograms

Sismanto, et. al. (2003a) associated the effect of absorption and dispersion according to Ganley (1981) with dispersion and attenuation. The attenuation effects are calculated from the wave number of Biot's equation. The theoretical seismograms are based on Ganley(1981)'s method. The dispersion effect comes from the reflectivity as a function of frequency. For the absorption calculation, Futterman(1962)'s absorption-dispersion equations, are realized.

Therefore, the synthetic seismograms cover reservoir parameters, elastic parameter and wave parameters. The permeability of the model depends on those parameters is given by Geertsma and Smit (1961),

\[ k_p = \frac{\phi \eta}{2\pi \rho \omega^2} \left[ \frac{V_p^4 - V_p^2 V_o^2}{V_p^2 V_o^2 - V_o^4} \right]^{1/2}. \quad (16) \]

The relationship of the permeability to the velocity and frequency for sandstone is illustrated in Fig. 1 and Fig. 2, respectively. Those figures show that for higher frequency the velocity dependency is not so significant relative to the permeability. Otherwise, the permeability is strongly influenced by the frequency. The relationship of dependency among frequency, velocity, and permeability has been discussed theoretically by Sismanto et al. (2005b).

The basic rock properties of marine sediment are based on Turgut and Yamamoto (1990). The kinematics viscosity of pure fluid \( \eta \) is 1.0 \( \times \) 10^3 m/s, the bulk modulus of fluid \( K_f \) is 2.3 \( \times \) 10^9 N/m^2, the bulk modulus of grain \( K_r \) is 3.6 \( \times \) 10^10 N/m^2, the density of fluid \( \rho_f \) is 1.0 \( \times \) 10^3 kg/m^3, and the density of grain \( \rho_r \) is 2.65 \( \times \) 10^3 kg/m^3. While, velocity of the P wave \( V_p \) is obtained from the seismic data, and the S wave velocity \( V_s \) and the density \( \rho \) are estimated by empirical equations (Mavko, et.al, 1998). Then, the bulk modulus of the skeletal frame and the porosity are estimated by Eqs.(4), Biot's elasticity parameters are determined by Eq.(3), and the velocity of the zero and the high frequency range are calculated by Eq.(7).

5. Examples of Numerical Result

Synthetic seismograms of poro-elastic waves in two layer models of seismic reflection are shown in Fig. 3. The model uses a velocity \( V_{p1} \) of 3000 m/s (sandstone) over the limestone with \( V_{p2} \) of 4000 m/s. The Ricker wavelet frequency is 70 Hz. Fig. 4 is the frequency spectrum of the synthetic seismogram events of Fig. 3. The spectrum shows that there is some frequency-shift and amplitude attenuation, especially in (10-70) Hz. The frequency content is affected by the attenuation system of the medium. The two-
layer model uses the thickness of first layer of 150 m and receiver interval of 20 m. Then, the other physical properties can be obtained such as the shear wave velocity \( V_{s1} \) and \( V_{s2} \), which are 1594 m/s and 2157 m/s, the density \( \rho_1 \) and \( \rho_2 \) are 2.19 \( \cdot \) 10\(^3\) kg/m\(^3\) and 2.33 \( \cdot \) 10\(^3\) kg/m\(^3\), the porosity \( \phi_1 \) and \( \phi_2 \) are 56 % and 17 %, and the permeability \( k_{p1} \) and \( k_{p2} \) are 278 mD and 209 mD, respectively. Those physical properties are enforced to construct the synthetic seismogram of the two-layer model, which is shown in Fig. 3. The permeability value of the synthetic seismogram, which is calculated from Eq.(16), is implemented as a reference.

Some two-layer models are constructed with the \( V_{p1} \) velocity of sandstone as first layer; of 3000 m/s and the thickness is 150 m over the limestone in which the velocity is 4000 m/s. The synthetic seismograms use several frequencies, and several velocity variations. When the velocity is put to be constant, the frequency is varied and vice versa. The permeability inversion of the two-layer model by the linear method is compared to the reference permeability; it gives equivalence function for several velocities and various frequencies. The scale factor of calibration is obtained from those curves. The scale factors are not unique, but are as a function of velocity. In this case we divide them into 4 groups of scale factor in the same range value of permeability i.e., (3350-3800) m/s, (2950-3350) m/s, (2450-2950) m/s, and (2000-2450 m/s) intervals as presented in Fig. 5a and 5b. There is a linear correlation between the permeability of the model and the permeability from estimation. The linear function of this relation is called the scale factor of the calibration.

The inversion method is applied to estimate the permeability based on the known velocity of the model on the synthetic seismogram, and the results are given in Fig. 6 for constant frequency and varying velocity and Fig. 7 for constant velocity and varying frequency. The shape of curves in Figs 6 and 7 are similar to the theoretical curve in Figs. 1 and 2, formulated by Geertsma and Smit (1961). It means that the synthetic seismogram keeps the permeability information of the model and the inversion method is able to extract it from the (synthetic) seismograms. In the permeability estimation, the average errors for both linear methods are less than 5 %. The errors come from determination of the linear area in the curve. However, the permeability estimation with surface seismic data is basically possible but requires precise calibration.

6. Field Examples

We use 3D seismic data in a small area of Duri field, central Sumatra, Indonesia. The main processing steps are the True Amplitude Recovery, the Surface Consistent Amplitude, Velocity Analysis and NMO Correction, the Field and Residual static, the Common Offset Binning, the Bandpass Filtering, Muting and Killing, Alignment, Ensemble Stack/Combine, F-X Deconvolution, and Plotting.

We take 11 inlines and 19 xlines seismic for (1.5 \( \times \) 2.65) km\(^2\) in subsurface. In this area we have 6 wells, and only well SM/A (in the middle) which has core analysis. Some information from these wells is listed in Table I. Each data is contoured and read at each CDP for calculating with the seismic data. The top of the target layer of the seismic will be \( T_s \) data.
In calibration, we use the permeability of the core, and log data to match the position of the core into seismic data through the synthetic seismogram in part of Duri field. The calibration of the CDP position (close to well SM#A) is on inline 187 and xline 207. Before calibrating, we calculate the permeability estimation of the reservoir target, and we get $9.429 \times 10^4$ mD for alpha and $1.845 \times 10^5$ mD for amplitude ratio methods. On the other hand, the average of permeability core samples is $1.254 \times 10^3$ mD. If the estimation permeability is divided by the average core permeability, it will give an equivalence factor. This equivalence factor is then being applied to the formula for calculating the other seismic data in the study area. The example distributions of calibration seismic data in alpha and amplitude ratio methods are presented in Fig.10 and Fig.11, respectively. Equivalence factor physically comes from the simplification of the system that mathematically is not formulated in the equation.

The equivalence factor is to compensate the output of system parameters that are not involved in the equation. Consequently, this cumulative factor forms a correction system in the numerical results.

Using the selected isolated CDP data performs the calculations of permeability to all CDP in each line. The results are plotted as a permeability map such as presented in Fig. 8 for alpha and Fig. 9 for amplitude ratio methods on smoothed data. The permeability maps give difference value and distribution, but still in the same trend. Which one is closer to reality, needs a comparison map from other calculation as a reference. Unfortunately, we do not have it. If we have the reference map, we will know the close one and the errors, at least we can adjust it by determining the correction factor statistically. The differences of the both result methods may be caused by noise in the data, equivalence factor, and linearity selection of the data. In this case, the equivalence factor is a constant that is not a function of velocity and frequency. Another effect is the accuracy of the slope determination for each method, which is subjectively determined. Therefore, it will give some difference errors for both methods. We aware the calibration step is another problem in this study. It needs more core permeability in various velocity, frequency, and lithology. Regardless of these problems, a simple method to estimate the permeability from seismic data has been proposed, but it needs an empirical calibration factor (Sismanto, 2004).

7. Conclusions

The permeability of a porous medium has a significant effect on the frequency dependence of the attenuation even in the low frequency range relevant for surface seismic. For testing in synthetic seismograms with acceptable approximations a linear relationship between the absorption coefficient and the inverse square of the frequency has an error less than 5%. However, a key result of the study suggests that permeability estimation with surface seismic data is possible through it requires accurate calibration.

The application of the methods to the surface seismic reflection CDP data on the 3D seismic in small Duri field area, central Sumatra needs a processing to keep the relative amplitude, attenuation effect, and remove the noise. The test results of both methods give a difference map; it is due to the noise on the data, slope determination, and non-uniqueness of the equivalence factor in calibration. The calibration step is an important stage, and it

Tabel I. The thickness, interval, and rms velocity of the well in Duri field.

<table>
<thead>
<tr>
<th>Well number</th>
<th>Interval velocity (m/s)</th>
<th>Rms velocity (m/s)</th>
<th>Thickness (m)</th>
</tr>
</thead>
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<tr>
<td>SM#1</td>
<td>2059</td>
<td>1715</td>
<td>34.75</td>
</tr>
<tr>
<td>SM#2</td>
<td>2129</td>
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<tr>
<td>SM#5</td>
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<td>1789</td>
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</tr>
<tr>
<td>SM#A</td>
<td>2057</td>
<td>2014</td>
<td>31.09</td>
</tr>
</tbody>
</table>
needs more training (testing) data that vary in velocity, frequency, and lithology.

Acknowledgments

We gratefully acknowledge the Geophysical Institute, Karlsruhe, Germany for providing facility during the research, the QUE project of the Geophysics Study Program, Gadjah Mada University, for financial support, and the invaluable support of PT CPI especially the following collaborators for their help: Mr. Marhadi, Mr. E.B. Hamzah, Mr. Supriadi Arif, Mr. Maryanto, and ESI team in Rumbai.

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References

The relationship of the permeability to the velocity for sandstone type. It is shown that for higher frequency the velocity dependency is not so significant relative to the permeability.

Fig. 1.

Fig. 2. The relationship of the permeability to the frequency for sandstone type. This relationship shows that the permeability is strongly influenced by frequency.

Fig. 2.

This relationship shows that the permeability is strongly influenced by frequency.

Fig. 3. Synthetic seismograms of poroelastic waves in two layer models of seismic reflection. The model uses a velocity $V_{pl}$ of 3000 m/s (sandstone, 150 m) over the limestone $V_{p2}$ of 4000 m/s, using Ricker wavelet frequency of 70 Hz.

Fig. 3.

There are some frequency-shift and amplitude attenuation, especially in the (10-70) Hz. The frequency content is affected by the attenuation system of the medium.

Fig. 4.

Fig. 4.
Fig. 5a and b. Curve of permeability of estimation versus permeability of model. It is shown that the equivalence factors are not constant, but they are as a function of velocity. We divide the velocity into 4 groups of equivalence factor in the same range value of permeability i.e., (3350-3800) m/s, (2950-3350) m/s, (2450-2950) m/s, and (2000-2450) m/s intervals.

Fig. 6. The permeability estimation curves (* is the alpha method, + is the amplitude ratio method) and the model permeability (o) with constant frequency are shown as curvature lines. Each has about 1% average errors.

Fig. 7. The permeability estimation curve (* is alpha method, + is amplitude ratio method) and the model permeability (o) with constant velocity are shown as linear lines. Each has about 1.5% average errors.
Fig. 8a-b. The example distributions of calibration seismic data (at Well SM#A) in alpha method.

Fig. 9a-b. The example distributions of calibration seismic data (at Well SM#A) in amplitude ratio method.

Fig. 10. The permeability map of Duri field resulted from Alpha method on smoothed data.

Fig. 11. The permeability map of Duri field resulted from the amplitude ratio (RA) method on smoothed data.
<table>
<thead>
<tr>
<th>DATE</th>
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<td>May</td>
<td>6 Travel CGK - SIN - SFO/LAX - Austin</td>
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<td>7 Austin: Gravimeter Test/Repair Facility</td>
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<td>8 Travel to Houston</td>
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<td>9 Registration, Ice break session</td>
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