Fracture-porosity inversion from P-wave AVOA data along 2D seismic lines: An example from the Austin Chalk of southeast Texas

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ABSTRACT

Vertical aligned fractures can significantly enhance the horizontal permeability of a tight reservoir. Therefore, it is important to know the fracture porosity and direction in order to develop the reservoir efficiently. P-wave AVOA (amplitude variation with offset and azimuth) can be used to determine these fracture parameters. In this study, I present a method for inverting the fracture porosity from 2D P-wave seismic data. The method is based on a modeling result that shows that the anisotropic AVO (amplitude variation with offset) gradient is negative and linearly dependent on the fracture porosity in a gas-saturated reservoir, whereas the gradient is positive and linearly dependent on the fracture porosity in a liquid-saturated reservoir. This assumption is accurate as long as the crack aspect ratio is less than 0.1 and the ratio of the P-wave velocity to the S-wave velocity is greater than 1.8 — two conditions that are satisfied in most naturally fractured reservoirs. The inversion then uses the fracture strike, the crack aspect ratio, and the ratio of the P-wave velocity to the S-wave velocity to invert the fracture porosity from the anisotropic AVO gradient after inferring the fluid type from the sign of the anisotropic AVO gradient. When I applied this method to a seismic line from the oil-saturated zone of the fractured Austin Chalk of southeast Texas, I found that the inversion gave a median fracture porosity of 0.21%, which is within the fracture-porosity range commonly measured in cores from the Austin Chalk.

INTRODUCTION

Although fractures do not contribute significantly to the reservoir porosity, they can enhance the reservoir permeability dramatically if the fractures are open and connected. In particular, vertical aligned fractures produce enhanced horizontal permeability in a tight reservoir with preferential fluid flow parallel to the fractures. Therefore, knowledge of the fracture strike and porosity (intensity) is crucial to any further development of the reservoir.

The effect of aligned fractures on seismic waves has been studied extensively for many years. Remarkably, Hudson (1981) introduced expressions for the velocities and attenuation of P- and S-waves in cracked media; these expressions were modified later to include the effect of equant porosity (Hudson et al., 1996a). Thomsen (1995) developed his weak elastic anisotropy theory (Thomsen, 1986) to study the combined effects of aligned cracks and equant porosity on seismic velocities. Schoenberg and Sayers (1995) used the normal and tangential fracture compliances to derive the effective elastic constants in a fractured medium. Bakulin et al. (2000) reviewed different theories of cracked media and compared their feasibility for fracture-parameter estimation.

Several seismic methods have been used to characterize naturally fractured reservoirs. These include analysis of multicomponent surface seismic data (e.g., Vitri et al., 2003), analysis of VSP (vertical seismic profile) data (e.g., Dewangan and Grechka, 2003), and analysis of surface P-wave seismic data (e.g., Hall and Kendall, 2003), to name a few. Analysis of multicomponent surface seismic data has the advantage of multiple sources of information in the form of P-wave and S-wave seismic sections, but requires special acquisition and processing techniques that may not be economically feasible. Analysis of VSP data has the advantage of recording data near the reservoir, thereby bypassing complications introduced by the overburden, but requires a borehole that is available for the whole survey period, a rather prohibitive constraint for productive boreholes. In contrast, analysis of surface P-wave seismic data requires no borehole or special acquisition techniques, but is hampered by an ambiguity in determining fracture orientations if only amplitudes are used (Ruger, 2002). In this paper, I present a method for inverting fracture porosity from 2D surface P-wave seismic data by using AVOA (amplitude variation with offset and azimuth) analysis. I then apply the method to data from the Austin Chalk of southeast Texas.

P-WAVE AVOA IN FRACTURED MEDIA

The P-P wave reflection coefficient

The P-P wave reflection coefficient in a reservoir with a single set of vertical aligned fractures and an isotropic background medium was approximated by MacBeth (2002) and Ruger (2002) as

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The expressions for $R_0$ and the isotropic AVO gradient are

$$R_0 = \frac{1}{2} \left( \frac{\Delta \alpha}{\bar{\alpha}} + \frac{\Delta \rho}{\bar{\rho}} \right),$$

and

$$G_I = \frac{\Delta \alpha}{2 \bar{\alpha}} - 2 \eta \left( \frac{\Delta \rho}{\bar{\rho}} + \frac{2 \Delta \beta}{\bar{\beta}} \right),$$

respectively, where $\alpha$ is the P-wave velocity, $\rho$ is the density, $\beta$ is the S-wave velocity, $\eta = (\beta/\alpha)^2$, $\Delta$ represents the difference, and a bar above a variable represents the average in a property across the interface between the isotropic and anisotropic media.

The anisotropic AVO gradient ($G_A$)

I use the fracture model proposed by Hudson et al. (1996b) composed of two welded surfaces in contact except at a series of small, randomly distributed, penny-shaped voids (cracks). Therefore, $G_A = \eta e_i - \zeta e_n$, where $\zeta = 1 - 2 \eta$ and $e_i$ is the normal fracture compliance. Both $\zeta$ and $\eta$ are those of the background isotropic medium. The tangential fracture compliance is

$$e_t = \frac{4 \Phi_c}{\pi a (3 - 2 \eta) \left( 1 - \frac{3}{4} A_0^{3/2} \right)},$$

where $\Phi_c$ is the total fracture porosity, $a$ is the average aspect ratio (width/length) of the cracks, and $A_0$ is the fractional area of cracks on the fracture surface. Typical values of $A_0$ are between 0.1 and 0.3.

![Figure 1. A surface plot of $G_A$ as a function of $\Phi_c$ (between 0 and 0.03) and $S_i$ (between 0 and 1) for the specific values of $a = 0.001$, $\alpha/\beta = 1.9$, $F_n = 0.0187$, and $A_0 = 0.2$. These values correspond to an oil reservoir in fractured limestone.](image)

The normal fracture compliance ($e_n$)

The normal fracture compliance in a partially saturated fractured reservoir is

$$e_n = \frac{e_n^0 (1 - e_t) + S_i (e_n^0 - e_t)}{1 + S_i (e_n^0 - e_t)},$$

where $e_n^0$ and $e_t$ are the normal fracture compliances for a $100\%$ gas-saturated and a $100\%$ liquid-saturated fracture, respectively, and $S_i$ is the liquid saturation in the fracture. “Partially saturated” here means a multiphased pore fluid. Equation 7 holds as long as each crack is filled with a single fluid phase and the fluids are immiscible, which are generally good assumptions in naturally fractured reservoir conditions (MacBeth, 2000). Putting $S_i = 0$ in equation 7 yields $e_n = e_n^0$, i.e.,

$$e_n^0 = \frac{\Phi_c}{\pi a \eta (1 - \eta) \left( 1 - \frac{3}{4} A_0^{3/2} \right)},$$

whereas putting $S_i = 1$ yields $e_n = e_t$, i.e.,

$$e_n^t = \frac{\Phi_c}{F_n + \pi a \eta (1 - \eta) \left( 1 - \frac{3}{4} A_0^{3/2} \right)},$$

where $F_n$ is the crack-filling liquid factor

$$F_n = \frac{\rho_c \alpha c^2}{\rho a^2},$$

and $\rho_c$, $\rho$, $\alpha_c$, and $\alpha$ are the densities and P-wave velocities of the crack-filling liquid and background isotropic medium, respectively.

It is obvious from equations 5, 6, 8, and 9 that $G_A$ will be linearly dependent on $\Phi_c$ for $100\%$ gas or liquid saturation (MacBeth, 2000). However, for intermediate values of $S_i$, $G_A$ is related to $\Phi_c$ in a more complicated way, making the inversion of $\Phi_c$ from $G_A$ impossible without knowing $S_i$. Because $F_n$ and $A_0$ have relatively insignificant influence on $G_A$ (Al-Shuhail, 2004), the significant parameters are only $a$, $\alpha/\beta$, $\Phi_c$, and $S_i$. Figure 1 shows a surface plot of $G_A$ as a function of $\Phi_c$ (between 0 and 0.03) and $S_i$ for the specific values of $a = 0.001$, $\alpha/\beta = 1.90$, $F_n = 0.0187$, and $A_0 = 0.2$. These values have been selected to reflect an oil reservoir in fractured limestone. Figure 1 shows that $G_A$ is negative for full gas saturation and positive for full liquid saturation and that $G_A$ has a linear dependence on $\Phi_c$ only at full saturations. This feature was suggested as a crack-filling-fluid discriminator (i.e., gas versus liquid) by MacBeth (2000) for $\alpha/\beta$ ratios between 1.81 and 2.65. Another peculiar feature in Figure 1 is the instability of $G_A$ following a specific trend of $\Phi_c$ and $S_i$. This instability occurs because the denominator of $e_n$ (equation 7) becomes zero and $G_A$ becomes infinite at these values of $\Phi_c$ and $S_i$. It should be noted that this trend changes with different combinations of $a$ and $\alpha/\beta$. One reason that the use of this method is prohibited at intermediate values of $S_i$ is this instability feature. Therefore, I will assume that a negative $G_A$ sign indicates gas-saturated fractures, whereas a positive sign indicates liquid-saturated fractures. Next, I will use this assumption to present a procedure for fracture-porosity inversion along 2D seismic lines.

FRACTURE-POROSITY INVERSION ALONG A 2D SEISMIC LINE

The input parameters to the proposed inversion procedure are shown in Table 1. In addition, the reservoir layer with the potential
Fracture porosity inversions using AVOA

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hydrocarbon fill is known. The layer at the other side of the interface where the analysis is done must have small or no fracture porosity; thus, the reservoir layer is the highly fractured or the only fractured layer. Finally, as already stated, a negative sign of $G_1$ indicates a gas-saturated reservoir, whereas a positive sign indicates a liquid-saturated reservoir.

The inversion procedure consists of first computing the following two parameters for the whole line: (1) A scaling factor ($SF$) can be calculated by dividing the median value of $R_0$, calculated from well logs by the median value of $I_{raw}$ computed from all CDPs in the line (Al-Shuhail, 2004). This scaling factor is used to transform $I_{raw}$ and $G_{raw}$ to scaled AVO intercepts ($I$) and gradients ($G$). (2) A factor $D$ (Al-Shuhail, 2004) is calculated from the properties of fractures, fracture-filling liquid, and background medium:

$$D = \eta_1 \left[ \frac{4}{\pi a (3 - 2 \eta_1)} \left( 1 - \frac{3}{4} \frac{3}{2} \right) \right] - \frac{1 - 2 \eta_1}{F_n + \pi a \eta_1 (1 - \eta_1) \left( 1 - \frac{3}{4} \frac{3}{2} \right)}.$$

(11)

After computing $SF$ and $D$, the procedure consists of performing the following six steps at every CDP along the line:

1) Multiply $I_{raw}$ and $G_{raw}$ values by $SF$ to obtain $I$ and $G$.
2) Calculate $\Delta \alpha/2\overline{\alpha}$ from $I$ and $\Delta \rho/2\overline{\rho}$ as $\Delta \alpha/2\overline{\alpha} = I - \Delta \rho/2\overline{\rho}$.
3) Calculate $\Delta \beta/2\overline{\beta}$ by using the relationship

$$\Delta \beta/2\overline{\beta} = \frac{\beta_3 - \beta_5}{\beta_3 + \beta_5} = \sqrt{\eta_1 (1 + \Delta \alpha/2\overline{\alpha})} - \sqrt{\eta_1 (1 - \Delta \alpha/2\overline{\alpha})}$$

(12)

where $\beta_3 = \sqrt{\eta_1 \alpha_3}$ and $\beta_5 = \sqrt{\eta_1 \alpha_5}$ are the S-wave velocities of the fractured and unfractured media, respectively. The factors involving $\Delta \alpha/2\overline{\alpha}$ come from the formulas $\alpha_3 = \overline{\alpha} [1 - (\Delta \alpha/2\overline{\alpha})]$ for the fractured medium and $\alpha_5 = \overline{\alpha} [1 + (\Delta \alpha/2\overline{\alpha})]$ for the unfractured medium (Shuey, 1985). I am assuming here that the fractured medium overlies the unfractured medium, as is the case for the fractured Austin Chalk that overlies the unfractured Eagleford Shale in the study area of the presented example.

4) Next, calculate $G_1$ by using equation 4.
5) Then calculate $G_A$ by using equation 2, i.e.,

$$G_A = \frac{G - G_1}{\sin^2 \phi}.$$  

(13)

Note that equation 13 cannot be used for calculating $G_A$ if the seismic line is parallel to the fracture strike, in which case $\phi = 0^\circ$, which makes $G = G_1$ and $G_A$ indefinite (see equation 2).

6) Finally, calculate $\Phi_c$ from $G_A$ by assuming linear dependence, i.e.,

$$\Phi_c = G_A/D,$$  

(14)

where $D$ is the factor calculated in equation 11.

APPLICATION TO DATA FROM THE AUSTIN CHALK

The Austin Chalk is a naturally fractured reservoir with a dominant set of vertical fractures trending northeast. The study area is in Gonzales County of southeast Texas. Figure 2 shows a location map

![Figure 2](image-url)
of the study area with a contour plot of the estimated ultimate recovery (EUR) of oil calculated from 114 horizontal wells producing oil from the Austin Chalk. These wells produced mainly oil and water with trace amounts of gas, if any. Figure 2 also demonstrates that the analyzed seismic line lies in a fairly oil-productive zone with an EUR of 50,000–100,000 BBL. Figure 3a shows azimuth, caliper, and microresistivity logs from the well indicated in Figure 2. These logs indicate that the Austin Chalk is fractured in the study area with northeast-trending fractures (Al-Shuhail, 1998). Figure 3b shows sonic and density-porosity logs from the same well indicating a very high contrast at the interface between the Austin Chalk and the underlying Eagleford Shale. The AVOA analysis is carried out on the reflection from the bottom of the Austin Chalk at its interface with the Eagleford Shale. The following input parameters, and those in Table 2, were either assumed or are available from previous studies (Al-Shuhail, 1998, 2004; Al-Shuhail and Watkins, 2000): I assumed an average value of $\alpha_1/\beta_1 = 2.06$ for the Austin Chalk, determined by Al-Misnid (1994) by using 2D P-wave and S-wave surface seismic data in Burleson County, which is located to the north of my study area. This value is very close to the values reported by Waters (1987) for chalks (2.08–2.13). For the Eagleford Shale, I calculated $\alpha_2/\beta_2 = 2.08$ by using the $\alpha$ and $\beta$ shale relationship of Castagna et al. (1993), where a median well-log value of $\alpha_2 = 3000$ m/s was used. $F_o = 0.0187$ was calculated by assuming a 100% oil saturation with $\alpha_1 = 1400$ m/s and $\rho_1 = 750$ kg/m$^3$, and median well-log values of $\alpha_1 = 5540$ m/s and $\rho_1 = 2607$ kg/m$^3$ are used for the background chalk.

I apply this procedure on a line that has an azimuth of N56°W, giving an azimuthal angle of $\phi = 64^\circ$. This data set consists of $I_{raw}$ and $G_{raw}$ from 31 CDPs (common depth points) along this conventionally recorded 2D seismic line. Figure 4 shows a stacked section of the analyzed line; Figure 5 shows the CDP gathers used in the analysis. First, $SF = 0.0721$ was calculated, and then steps 1 to 6 of the procedure were performed at every CDP. Table 3 shows the calculations associated with the raw data at every CDP. Figure 6 shows plots of the scaled values of $G$ and $I$. The calculated $G_s$ and $\Phi_s$ values are shown in Figures 7a and b, respectively. The median value of $\Phi_s$ along this line is 0.21%, which lies within the fracture-porosity

Table 2. Input parameters for Austin Chalk example.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value used</th>
</tr>
</thead>
<tbody>
<tr>
<td>Median fracture strike</td>
<td>N60°E</td>
</tr>
<tr>
<td>Median value of $a$</td>
<td>0.000 675</td>
</tr>
<tr>
<td>$A_0$</td>
<td>0.2</td>
</tr>
<tr>
<td>Median well-log value of $\Delta p/\bar{\rho}$</td>
<td>−0.1027</td>
</tr>
<tr>
<td>Median well-log value of $R_0$</td>
<td>−0.339</td>
</tr>
<tr>
<td>$D$ (from equation 11)</td>
<td>182</td>
</tr>
</tbody>
</table>

Figure 3. (a) Logs of a fractured part of the Austin Chalk from the well indicated in Figure 2. Azimuth (P1AZ) curve indicates the azimuth of pad 1 (clockwise from north) of the microresistivity log. P1, P2, P3, and P4 indicate the microresistivity readings of pads 1, 2, 3, and 4 of the microresistivity log, respectively. C1 indicates the well diameter along the 1–3 caliper arm, and C2 indicates the well diameter along the 2–4 caliper arm. Note the borehole ellipticity in the intervals 2130.3–2132.1 m and 2134.2–2136.4 m, which indicates fracturing. Also note the different microresistivity readings of adjacent pads (pad 1 and pad 2) in the same intervals, which also indicate fracturing. (b) Sonic and density-porosity logs from the well indicated in Figure 2. BAC (bottom of Austin Chalk) indicates the interface between the Austin Chalk and the underlying Eagleford Shale.

Figure 4. Stacked section of the analyzed seismic line zoomed on the Austin Chalk. Vertical axis is two-way traveltime in milliseconds, and horizontal axis shows CDP numbers and distance along the line. The well shown in Figure 3 is located at CDP 221. BAC indicates the reflection from the interface between the Austin Chalk and the underlying Eagleford Shale (at about 1570 ms), which was used for the analysis of prestack data. The AVOA analysis was done on the reflection from the BAC by using only the data from CDPs 220–250 because they provide the offsets required for AVOA analysis.
Table 3. The calculations associated with the raw data at every CDP.

<table>
<thead>
<tr>
<th>CDP</th>
<th>$I_{raw}$</th>
<th>$G_{raw}$</th>
<th>$I$</th>
<th>$G$</th>
<th>$\Delta a/2a$</th>
<th>$\Delta \beta/\beta$</th>
<th>$G_a$</th>
<th>$G_s$</th>
<th>$\Phi_r$</th>
</tr>
</thead>
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<td>6.6068</td>
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<td>0.4767</td>
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<td>−0.6661</td>
<td>−0.1824</td>
<td>−0.3791</td>
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<td><strong>Median</strong></td>
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<td><strong>−0.4861</strong></td>
<td><strong>0.2631</strong></td>
<td><strong>0.2897</strong></td>
<td><strong>0.21%</strong></td>
</tr>
</tbody>
</table>

Note: NA indicates that fracture porosity was not calculated at this CDP because of its negative $G_s$ value, which is not possible for an oil-saturated fractured reservoir (see text for possible reasons).
Figure 5. Snapshots of all CDPs used in the analysis zoomed on the Austin Chalk. Numbers at the top of each panel indicate the CDP number. $X_{max}$ indicates the maximum offset associated with each CDP. The vertical axis is the two-way traveltime in milliseconds. Arrow indicates the reflection from the BAC (bottom of Austin Chalk) at about 1570 ms, where the AVO analysis was done. (a) CDPs 220–230, (b) CDPs 231–240, and (c) CDPs 241–250.

Figure 6. A plot of the scaled $I$ (empty squares) and $G$ (filled circles) values that were used in the inversion. The dashed line indicates the median $G$, and the dotted line indicates the median $I$. Scaling was done by multiplying the raw AVO intercept and gradient ($I_{raw}$ and $G_{raw}$) by the scaling factor (SF).

Figure 7. (a) A plot of the calculated $G_A$ values. The dashed line indicates the median $G_A$ value. Negative $G_A$ values have not been interpreted as indicating gas because only liquids are produced from the reservoir at that depth. Therefore, the negative values have been excluded from the inversion process. (b) A plot of the inverted $\Phi$ values. The dashed line indicates the median $\Phi$ value (see text for possible explanations for the observed scatter in the results).

CONCLUSIONS

I present a method for fracture-porosity inversion from 2D P-wave seismic data using AVOA analysis and show an example from the Austin Chalk of southeast Texas. The method depends on modeling results that show that the anisotropic AVO gradient is linearly dependent on the fracture porosity in fully saturated fractured reservoirs; a positive sign implies a liquid-saturated reservoir and a negative sign implies a gas-saturated reservoir. The method is limited to the cases of gas-saturated and liquid-saturated reservoirs and fails for partially saturated reservoirs (those in which pore fluid is multphased). In addition, the proposed method requires that the fracture orientation and the crack aspect ratio must be known a priori. Therefore, the application of the method is limited to well-developed fractured reservoirs. Possible scenarios for the application of this method include planning a horizontal production well and estimating the fracture porosity available for subsurface storage of fluids.

Furthermore, it should be noted here that the seismic line used in the study was not ideal for azimuthal AVO analysis because of limited offset range, low-to-fair quality, and azimuthal angle ($\phi = 64^\circ$) that was not normal to the fracture strike. These conditions of the data might be the reason for the scatter in the results of the inversion shown in Figure 7. Nevertheless, the method was successful in deter-
Fracture porosity inversions using AVOA

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LIST OF SYMBOLS WITH DEFINITIONS

\[ R = \text{P-P-wave reflection coefficient} \]
\[ R_0 = \text{P-P-wave normal-incidence reflection coefficient} \]
\[ G(\phi) = \text{total AVO gradient along the azimuth } \phi \]
\[ G_A = \text{anisotropic AVO gradient} \]
\[ \theta = \text{angle of incidence} \]
\[ \phi = \text{azimuthal angle between fracture strike and seismic line} \]
\[ \beta = \text{S-wave velocity} \]
\[ \eta = (\beta/\alpha)^2 \]
\[ \zeta = 1 - 2\eta \]
\[ e_r = \text{tangential fracture compliance} \]
\[ e_n = \text{normal fracture compliance} \]
\[ \Phi_e = \text{total fracture porosity} \]
\[ a = \text{average aspect ratio (width/length) of cracks} \]
\[ A_0 = \text{fractional area of cracks on the fracture surface (typically 0.1–0.3)} \]
\[ e_r^g = \text{normal fracture compliance for full gas saturation} \]
\[ e_n^g = \text{normal fracture compliance for full liquid saturation} \]
\[ S_l = \text{liquid saturation in the fracture} \]
\[ F_n = \text{crack-filling liquid factor} \]
\[ p_l = \text{density of crack-filling liquid} \]
\[ \alpha_l = \text{P-wave velocity of crack-filling liquid} \]
\[ \rho = \text{density of background (unfractured) medium} \]
\[ \alpha = \text{P-wave velocity of background (unfractured) medium} \]
\[ I_{raw} = \text{raw AVO intercept at a CDP} \]
\[ G_{raw} = \text{raw AVO gradient at a CDP} \]
\[ I = \text{scaled AVO intercept at a CDP} \]
\[ G = \text{scaled AVO gradient at a CDP} \]
\[ SF = \text{scaling factor that transforms } I_{raw} \text{ and } G_{raw} \text{ to } I \text{ and } G \]
\[ D = \text{factor calculated from properties of cracks, fractures, fracture-filling liquid, and background medium} \]

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