CHARACTERIZATION OF IN-SITU STRESS AND PERMEABILITY IN FRACTURED RESERVOIRS

SEMI-ANNUAL TECHNICAL PROGRESS REPORT

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by

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Abstract

During the past six months we have adapted our 3-D elastic, anisotropic finite difference code by implementing the rotated staggered grid (RSG) method to more accurately represent large contrasts of elastic moduli between the fractures and surrounding formation, and applying the perfectly matched layer (PML) absorbing boundary condition to minimize boundary reflections. Two approaches for estimating fracture spacing from scattered seismic energy were developed. The first relates notches in the amplitude spectra of the scattered wavefield to the dominant fracture spacing that caused the scattering. The second uses conventional FK filtering to isolate the backscattered signals and then recovers an estimate of the fracture spacing from the dominant wavelength of those signals. Both methods were tested on synthetic data and then applied to the Emilio field data. The spectral notch method estimated the Emilio fracture spacing to be about 30 to 40 m, while the FK method found fracture spacing of about 48 to 53 m. We continue to work on two field data sets from fractured carbonate reservoirs provided by our industry sponsors—the offshore Emilio Field data (provided by ENI-AGIP), and an onshore reservoir from the Middle East (provided by Shell). Calibration data in the form of well logs and previous fracture studies are available for both data sets. In previous reports we showed the spatial distribution fractures in the Emilio Field based on our calculated scattering index values. To improve these results we performed a map migration of all the scattering indices. The results of this migration process show a very strong correlation between the spatial distribution and orientation of our estimated fracture distribution and the fault system in the field. We observe that the scattering index clusters tend to congregate around the fault zones, particularly near multiple faults and at fault tips. We have also processed a swath of data from the second data set (the onshore carbonate field). FMI data are available from a number of wells for comparison to our seismic scattering analysis results. The agreement is very good, providing confidence that these methods can be applied to land seismic data that do not have the ideal azimuthal coverage.

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I. Executive Summary

The purpose of this project is to develop and implement large-scale numerical models to quantify the effects of fracture parameter variations on seismic reflection signals and in-situ stress variations on flexural modes in boreholes. These models will be used as the basis of data analysis and inversion routines for estimating the heterogeneous fracture distribution in fractured reservoirs from seismic and borehole field data. Fracture property distributions estimated from seismic data will be used to estimate the permeability tensor in the reservoir for input to reservoir simulators.

During the past six months we have adapted our 3-D elastic, anisotropic finite difference code in two ways. First, we implemented the rotated staggered grid (RSG) method to more accurately represent large contrasts of elastic moduli between the fractures and surrounding formation. Second, we applied the perfectly matched layer (PML) absorbing boundary condition to minimize boundary reflections. This adapted code has been used for a comparative study of the azimuthal AVO signatures from a medium with small scale fractures (i.e., an effective medium representation of a fractured reservoir) and a medium with large scale discrete fractures. We compared the AVOaz magnitudes using effective media (EMM) and discrete fracture (DFM) models. Based on synthetic waveforms generated by finite difference calculations, the AVOaz of the PP reflection from the top of a fractured reservoir is effected differently by distributed and discrete fracture distributions. Results from EMM show that for incidence angles of around 30 degrees the magnitude of AVOaz is a maximum, while the DFM results show larger AVOaz magnitude with farther offsets. Fracture orientation extracted from AVOaz based on the EMM and DFM could differ by 90 degrees for compliant fractures.

Fracture spacing is an important parameter in reservoir development. We have developed two approaches for estimating fracture spacing from scattered seismic energy. The first relates notches in the amplitude spectra of the scattered wavefield to the dominant fracture spacing that caused the scattering. The second uses conventional FK filtering to isolate the backscattered signals and then recovers an estimate of the fracture spacing from the dominant wavelength of those signals. Both methods were tested on synthetic data and then applied to the Emilio field data with similar results. The first method is based on the observation that discrete, vertically aligned fracture systems

impart one or more notches in the spectral ratios of stacked reflected seismic traces. This apparent attenuation is due to the azimuth dependant scattering introduced by the fractures. The most prominent notch is located at the frequency where the P wavelength is about twice the fracture spacing. The frequency location of the notches can be used to determine the fracture spacings. Azimuth stacks with an orientation parallel to the fractures tend not show these spectral notches – allowing for another way to detect the fracture orientation. The method was applied to the Emilio Field data resulting in fracture spacing estimates of about 30 to 40 m. In the second method we analyze the seismic data in the frequency-wavenumber (FK) domain. In our studies on the scattering effects of discrete fractures on synthetic seismic data we have observed the presence of both forward and backscattered signals. In particular, the backscattered signals (the energy that is propagating back towards the source) appear to be a maximum when the acquisition direction is normal to the fractures and a minimum when the direction is parallel to the fractures. In the FK domain we can separate the backscattered energy and determine the fracture spacing from its dominant wavenumber (i.e., wavelength). The technique was tested on synthetic model data, and then applied to the data from the Emilio field resulting in a fracture spacing estimate of about 48 to 53 m.

We continue to work on two field data sets from fractured carbonate reservoirs provided by our industry sponsors—the offshore Emilio Field data (provided by ENI-AGIP), and an onshore reservoir from the Middle East (provided by Shell). Calibration data in the form of well logs and previous fracture studies are available for both data sets. In previous reports we showed the spatial distribution fractures in the Emilio Field based on our calculated scattering index values. To improve these results we performed a map migration of all the scattering indices. The results of this migration process show a very strong correlation between the spatial distribution and orientation of our estimated fracture distribution and the fault system in the field. We observe that the scattering index clusters tend to congregate around the fault zones, particularly near multiple faults and at fault tips. In addition, we see that the quivers tend to align either parallel or perpendicular to the faulting. There is very good agreement between the scattering index orientations and the well-derived fracture orientations at three wells in the field. We have also processed a swath of data from the second data set (the onshore carbonate field).

FMI data are available from a number of wells for comparison to our seismic scattering analysis results. The agreement is very good, providing confidence that these methods can be applied to land seismic data that do not have the ideal azimuthal coverage.

II. Introduction

The purpose of this project is to develop and implement large-scale numerical models to quantify the effects of fracture parameter variations on seismic reflection signals and in-situ stress variations on flexural modes in boreholes. These forward modeling efforts will be used to develop data analysis and inversion routines for estimating the heterogeneous fracture distribution in fractured reservoir from seismic and borehole field data. These fracture property distributions will be used to estimate the permeability tensor in the reservoir by using statistical and discrete feature network techniques. Permeability estimates will then be used as inputs to reservoir simulators. The objective of the project is schematically displayed in Figure 1.

Figure 1. Schematic display of the project objectives. Surface 3-D seismic data is used to estimate the spatial distribution of fracture parameters (e.g., fracture density, spacing, orientation). A model is used to convert such fracture parameters into permeability values, which are input to reservoir simulators for history matching.

III. Results and Discussion

Our results during the past six month period involve adaptations to our numerical codes for modeling seismic scattering from fractures, the development and testing of two new methods for estimating fracture spacing from seismic data, and some new results of applying our methods to field data from fractured carbonate reservoirs. Each of these areas will be addressed in the following sections.

III.A. Fracture properties from seismic data

III.A.1. Numerical modeling

a. Finite difference model adaptations and AVOaz comparisons of effective medium and discrete fracture models

As part of our ongoing numerical modeling tasks we have adapted our 3-D elastic, anisotropic finite difference code in two ways. First, we implemented the rotated staggered grid (RSG) method developed by Saenger (2004). The RSG method can more accurately represent large contrasts of elastic moduli between the fractures and surrounding formation. Second, we applied the perfectly matched layer (PML) absorbing boundary condition to minimize boundary reflections (Marcinkovich and Olsen, 2003). This adapted code has been used for a comparative study of the azimuthal AVO signatures from a medium with small-scale fractures (i.e., an effective medium representation of a fractured reservoir) and a medium with large scale discrete fractures (Figure 2).

Figure 2. Configuration of fractures in the EMM and DFM. EMM: small cracks evenly distributed within the layer form an effective HTI media; DFM: single fractures composed of small cracks with the same properties as the EMM, such as crack density, aperture and fluid inclusions, discretely distributed with spacing comparable to seismic wavelength.

We compared the AVOaz magnitudes using effective media (EMM) and discrete fracture (DFM) models. The crack properties are the same for both models, with the cracks distributed throughout the fractured layer for the EMM and clustering on discrete single fracture zones for the DFM. For the DFM, fracture lengths and spacings are comparable to the seismic wavelength. Based on synthetic waveforms generated by finite difference calculations, the AVOaz of the PP reflection from the top of a fractured reservoir is effected differently by distributed and discrete fracture distributions. Results from EMM show that for incidence angles of around 30 degrees the magnitude of AVOaz is a maximum, while the DFM results show larger AVOaz magnitude with farther offsets (Figure 3). Fracture orientation extracted from AVOaz based on the EMM and DFM could differ by 90 degrees for compliant fractures (Figure 3). More details on these models and results are provided in Appendix A (Zhang et al., 2005).

Figure 3. Comparison of AVOaz in directions perpendicular and parallel to the strike of compliant fractures based on EMM and DFM. The four panels are for different fracture spacing (20m, 30m, 40m, 50m) of the DFM. Note that opposite trends of AVO behavior can be seen for the two different model types. For the EMM model, amplitudes are higher at 0 degree (normal to fractures) azimuth (dashed red line) than at 90 degree (parallel to fractures) azimuth (dashed blue line), while the opposite trend holds for the DFM (solid red line is lower amplitude than the solid blue line).

b. Nonorthogonal fracture sets

The finite difference modeling codes we have been using implement the Coates-Schoenberg equivalent anisotropic medium approach for incorporating discrete fractures (Coates and Schoenberg, 1995). This formulation is quite general as it allows for modeling multiple intersecting sets of fractures with arbitrary orientations. However, in order to fully benefit from this flexibility, the finite-difference code must allow for fairly arbitrary anisotropy (at least monoclinic). In a short note by Chi and Campman (2005, see Appendix B), the method developed by Coates and Schoenberg (1995) and Hood (1991) are briefly reviewed followed by a discussion on how to compute the equivalent stiffness matrices of fractured media in various scenarios. The formulation for modeling wave propagation in media with non-orthogonal fracture sets (e.g., Figure 4) is described in some detail in Appendix B. The finite difference codes can be adapted to handle such situations.

Figure 4. Map view of an example of non-orthogonal fracture sets.

III.A.2. Data analysis: Fracture spacing estimation methods

Fracture spacing is an important parameter in reservoir development. We have developed two approaches for estimating fracture spacing from scattered seismic energy. The first relates notches in the amplitude spectra of the scattered wavefield to the dominant fracture spacing that caused the scattering. The second uses conventional FK filtering to isolate the backscattered signals and then recovers an estimate of the fracture spacing from the dominant wavelength of those signals. Both methods were tested on synthetic data and

then applied to the Emilio field data with similar results. In the sections below, the methods and results will be summarized. More detailed descriptions can be found in Appendix C (Willis et al., 2005a) and D (Grandi et al., 2005) respectively.

a. Spectral analyses from azimuthal stacks

Discrete, vertically aligned fracture systems impart one or more notches in the spectral ratios of stacked reflected seismic traces. This apparent attenuation is due to the azimuth dependant scattering introduced by the fractures. The most prominent notch is located at the frequency where the P wavelength is about twice the fracture spacing. The frequency location of the notches can be used to determine the fracture spacings. Azimuth stacks with an orientation parallel to the fractures tend not show these spectral notches – allowing for another way to detect the fracture orientation.

Overview of method

We first analyze synthetic seismic reflection traces created from our standard five layer model where the center layer is an isotropic reservoir containing discrete sets of gas-filled, vertical (Figure 5). We use models with different regular fracture spacings of 100m, 50m, 35m and one with a Gaussian distribution of fractures with a mean of about 35m. Azimuth stacks of the shot records are created at 10-degree increments from normal to parallel to the fractures. As in our previous studies, we find that scattered energy from the fractures is reinforced on the stacks parallel to the fractures and is reduced in the direction normal to the fractures. The left panel in Figure 6 shows the azimuth stacks for the 50m fracture spacing case.

From these azimuth stacks we create their associated transfer functions, as described by Willis et al. (2004a,b). Briefly, this process entails for each azimuth stack trace: (1) identifying a target depth range (the fractured layer) to investigate; (2) extracting a window of data containing reflections which are above this fractured layer (denoted as the ‘input’); (3) extracting a window of data below the fractured layer (denoted as the ‘output’) containing reflections which includes the scattered energy; (4) taking the autocorrelation of the extracted windows; (5) windowing the autocorrelations to focus on the source wavelet near zero lag; and (6) computing the spectra

ratio of the lower and upper windowed autocorrelations from the amplitude spectrum of the time domain transfer function (see Willis et al, 2004a, b; 2005). The right panel in Figure 6 shows the time domain transfer functions for the 50m fracture case.

Model Geometry

Figure 5. Model geometry – five layers with the center layer containing discrete vertical fractures.

Figure 6. Left panel shows the azimuth stacks for the 50m regularly spaced fracture model. The two highlighted areas show the input (left most) and output (right most) windows used to compute the associated transfer functions in corresponding traces in the right panel.

The mean of the corresponding amplitude spectra of the 50m case for azimuths within 40 degrees of normal to fracture strike is shown in Figure 7. On this display a deep notch in the spectrum at about 35 Hz can be seen. Since there is no attenuation in

the model we would expect to see a nearly flat spectral ratio over the bandwidth of about 10 to 80 Hz. This is not the case. At this particular frequency energy in the propagating signal happens to cancel out due to the time delay of a P wave traveling between two fractures and creating a null. The notch at about twice the fracture spacing is characteristic of all the models studied.

Figure 7. The mean of the spectral ratios for the 50m fracture case for azimuth stacks with orientations within 40 degrees of normal to the fracture strike. The vertical axis is in dB.

The notch effect is reduced for azimuths close to the fracture strike direction. This is due to the fractures acting like mechanical polarizers, channeling energy away from the normal direction, towards the parallel direction. Hence, in the parallel direction, there is in fact an amplification, or a peak in the spectral ratios. Thus, this azimuth sensitive behavior of the spectral ratios also provides fracture orientation. Lynn (2004b) noted holes in the spectra of shear components and attributed them to interference of backscattered energy.

Field data application

We apply the spectral notch method, described above for the model data, to analyze the seismic data from the Emilio field. We selected the near to mid range offsets of the preprocessed PP data (Vetri et al., 2003) and created eighteen different azimuth stack volumes from East to West using 20 degree wide overlapping ranges. We created two superbins to collect the stacked traces around wells 4 and 8. The size of each

superbin was 11x11 bins (125m x 250m). For each of the 18 azimuth stacks, the traces which fell within the two bins were collected. For each of these traces, a time window above, and another window below the reservoir were extracted and their autocorrelations computed. The spectral ratios were computed by spectral division of the fast Fourier transforms of the autocorrelations. We then averaged the spectral ratio values for all the traces with the same azimuth stack direction within the same superbin. For this data set, observable fracture spacings are expected to be in the range 20 to 120m.

Figure 8 shows the spectral ratio amplitudes as a function of azimuth and fracture spacing (defined as one half wavelength) for well 4 (left) and 8 (right). The vertical axis shows each of the 18 azimuths from East (represented by 0 degrees in our system), through North (90 degrees), to West (180 degrees). Clearly evident on the figure is a significant azimuthal variation of spectral ratio amplitudes. Further, prominent notches (blue) across a broad range of azimuths can be observed, particularly at fracture spacings of about 30m. From the model study, the notches are expected over a range of azimuths that are nearly perpendicular to the fracture direction. Additional features are the peaks (red) in both plots. Well 4 shows large amplitudes at about 70 and 120 degrees. Well 8 shows a band of large amplitudes at a range of azimuths from about 90 to 120 degrees. These larger amplitudes occur at spacings of 50 to 60 m, and are expected to indicate directions that are close to the fracture strike directions. Thus the peaks and troughs are expected over perpendicular azimuths if only a single, equally spaced fracture set is present.

Figure 9 shows the median spectral ratio, averaging over azimuths, for wells 4 (left) and 8 (right). A linear trend in the spectral ratio amplitude, attributable to attenuation (decreasing amplitude with increasing frequency), was removed. This curve amounts to a projection of the contours in Figure 8 along the x-axis. Troughs are evident in both plots, consistent with discrete fractures spacing of about 30 to 40 m. A second, weaker trough around 60 to 80 m (corresponding to twice the fracture spacing) is discernable, along with the peak around 50 to 60 m.

Figure 8. Spectral ratio functions for well 4 (left) and well 8 (right). The vertical axis is the direction of the azimuth stack where 0 degrees is East and 90 degrees it North. The horizontal axis is wavelength/2, which is interpreted as fracture spacing.

Figure 9. Averaged spectral ratios in the area around well 4 (left) and well 8 (right). The wavelength axis has been scaled by 2 so that fracture spacing may be read directly from the x-axis.

Some of these results can be validated with prior studies on this data. Figure 10a shows the borehole derived measurements for horizontal stress directions from Vetri et al. (2003), together with estimates of the aggregated fracture orientations from the analysis of scattering indices modified from Willis et al. (2004b) (Figure 10b). For comparison, we derive a polar plot of the spectral ratio amplitudes for the bins corresponding to well 4 and 8 in Figure 10c. Spectral ratio amplitudes are plotted versus angle, with the peak amplitudes identifying fracture directions. There is a reasonable consistency between the present results and prior work in overall fracture directions. It should be noted that the three measures are at different scales: stress direction measurements in Figure 10a are essentially “point” measurements localized around a borehole, whereas the scattering index measures (Figure 10b) are for an area covering about 0.5km x 1km and the spectral notch method measures (Figure 10c) are for an area of 0.125 km x .25 km. More details can be found in Willis et al. (2005a) in Appendix C.

Figure 10a. Borehole Measurements: Stress measurements from borehole break outs in well 4 (left) and from natural fractures observed in the borehole in well 8 (right) (modified from Vetri et al, 2003). Vertical fractures tend to be aligned with the maximum horizontal stress direction.

Figure 10b. Scattering Index: Rose diagrams showing fracture orientations in the area surrounding well 4 (left) and well 8 (right) from an analysis of scattering indices (Willis et al, 2004).

Figure 10c. Spectral Notch Method: Rose diagrams showing fracture orientations using the method described in this paper, for the area surrounding well 4 (left) and well 8 (right).

The estimated fracture spacing of 30–40 m for the Emilio Field will be compared to the estimates obtained from a second method (described in the next section) using FK analysis.

b. FK analysis of backscattered energy

We derived a methodology to determine orientation and average spacing of discrete fractures based on the analysis of seismic coda in the frequency-wavenumber (FK) domain. In the FK domain it is relatively easy to identify (and therefore separate) events with different apparent velocities in the seismic data. In our studies on the scattering effects of discrete fractures on synthetic seismic data we have observed the presence of both forward and backscattered signals. In particular, the backscattered signals (the energy that is propagating back towards the source) appear to be a maximum when the acquisition direction is normal to the fractures (top left panel of Figure 12), and a minimum when the direction is parallel to the fractures (bottom left panel of Figure 12). Since these signals are generated at the fractures, they will contain information related to the spacing of the fractures. In the FK domain we should be able to accomplish two goals. First, by identifying the direction of minimum backscattered energy we will obtain an independent estimate of the fracture orientation. Second, by separating and analyzing the backscattered signals we can obtain an estimate of the fracture spacing.

The seismic response of vertical, regularly spaced fractures, for different spacings, is studied through 3D finite difference models that incorporate discrete fractures (e.g., Figure 5). The modeled data are collected according to source-receiver azimuth (Figure 11) and subsequently transformed into the FK domain via a 2-D Fourier transform. Backscattered energy will fall into the negative wavenumber quadrant of the

FK plane (right panels of Figure 12). Two observations are made of the FK characteristics of azimuthal gathers at the fractured level: (1) the energy in the negative

Figure 11. Map view of the numerical model. The black dots are the receiver positions, the vertical red lines represent the discrete fractures, and the yellow lines show the azimuthal directions along which that synthetic data were analyzed. The fracture normal direction in this case is defined as 0 degrees, while the fracture strike direction is defined as 90 degrees.

Figure 12. Synthetic shot gathers normal (top left panel) and parallel (bottom left panel) to the fractures with the corresponding FK plot on the right (frequency is on the vertical axis, and wavenumber is on the horizontal axis). Backscattered energy can be seen in the top right panel (normal to fractures) in the negative wavenumber quadrant. None is visible for data parallel to the fractures.

wavenumber quadrant is a maximum for source-receiver azimuth normal to fractures and is a minimum along the fracture strike direction (Figure 13); and (2) the distribution of energy in this quadrant varies according to fracture spacing such that backscattered signal from shorter fracture spacings contains higher frequencies-wavenumbers. Fracture related signals can be isolated with pass/reject FK filters for further processing to specifically extract fracture parameters.

BACKSCATTERED ENERGY AND FRACTURE ORIENTATION

Figure 13. Plot of the ratio of the energy in the negative wavenumber quadrant (i.e., backscattered energy) to the total energy in the FK domain. The maximum amount of backscattered energy is found normal to fractures, and the minimum is parallel to fractures.

Analysis of synthetic data indicates that fracture spacing is related to the half wavelength (half of the ratio of the dominant velocity to dominant frequency) of the backscattered energy. Figure 14 shows the results of applying this method to the synthetic data for the 35m fracture spacing model. The top left panel shows the original shot gather for this model acquired normal to fractures, which contains all reflections and scattered energy. Using an FK filter the backscattered energy is separated from the data for analysis (middle panel), while the rightmost panel shows the remaining data after removing the backscattered energy. The estimated fracture spacing is found by computing the half-wavelength of the data based on the dominant wavenumber (0.0141/m) or the dominant frequency (80Hz) and apparent velocity (5820 m/s). The

method correctly estimates the fracture spacing of 35m. Figure 15 shows a plot of the peak energy in the FK spectra for the backscattered signals for models with different fracture spacing. In each case the fracture spacing can be accurately estimated by computing the half-wavelength of the backscattered data.

Figure 14. The top left panel shows the windowed data from the 35m fracture spacing model for the acquisition direction oriented normal to the fractures. The middle panel shows the backscattered signals passed by the FK filter, and the right panel shows the rejected signals. The bottom panel shows the FK spectrum of the backscattered signals with the dominant frequency, wavenumber and velocity indicated.

The technique is applied to the data from the Emilio field. Figure 16 shows the acquisition layout (receiver lines oriented NW/SE, with shot lines normal to the receiver lines), and the orientation convention used (e.g., East is 180 degrees, North is 270 degrees). The estimated preferential fracture orientation, obtained from the minimum backscattered energy direction, is about 190 degrees (N70°E – N80°E), as seen in Figure 17, which agrees with well data and seismic anisotropy studies. The leftmost panel in Figure 18 shows the seismic gather along in the 190 degree azimuth in the reservoir interval. The backscattered energy is separated from the data via an FK filter and shown in the middle panel of Figure 18. The rightmost panel shows the remaining data after the

backscattered energy is removed. At the bottom plot in the same figure, the dominant velocity of the backscattered energy is around 2400 m/s. The FK spectrum of the backscattered data, showed in Figure 19, exhibits an energy maximum at 24.6 Hz and -0.0094 1/m. By taking half of the inverse of the dominant wavenumber or, alternatively, half of the ratio of dominant velocity to dominant frequency, a fracture spacing of about 48 to 53 m is obtained. The estimated fracture spacing is in general agreement with the estimate obtained from the spectral notch method previously discussed.

Figure 15. Plot of the Energy maximum in the f-k spectrum as a function of fracture spacing. In all cases, fracture spacing is approximately half of the inverse of the dominant wavenumber: $(1/2)(1/0.0047\text{m}^{-1}) = 106.4\text{m}$; $(1/2)(1/0.0094\text{m}^{-1}) = 53.2\text{m}$; $(1/2)(1/0.0134\text{m}^{-1}) = 37.3\text{m}$; $(1/2)(1/0.0191\text{m}^{-1}) = 26.2\text{m}$.

SORTING AZIMUTHAL SHOT GATHERS

Figure 16. Map view of the acquisition geometry of the Emilio Field data showing the orientations of the azimuthal stacks used for FK analysis. The red dots show the shot point locations for the two black lines of receiver points that are oriented NW/SE. For this study, 0 degrees corresponds to West, 90 degrees to South, 180 degrees to East, and 270 degrees to North. Azimuthal stacks were examined for orientations ranging from about 110 degrees to 290 degrees.

Figure 17. Plot of the ratio of backscattered to total energy for a CDP location in the Emilio data as a function of azimuth. The red line shows the ratio for the entire analyzed section, the blue line for a constant time window bracketing the reservoir unit, and the green line for a variable time window that is centered on the reservoir for all azimuths. Note that the maximum backscattering direction for all cases is the same (approximately 190 degrees, representing the fracture normal direction) and the minimum is at about 290 degrees (the fracture strike direction).

Figure 18. FK filtering to isolate backscattered energy in the Emilio CDP gather with azimuthal orientation of 190 degrees (fracture normal direction). The top left panel is the total data, the middle panel is the backscattered events only, and the right panel is the residual (i.e., the remainder after removing the backscattered data from the total data). The dominant velocity is observed consistently around 2400 m/s.

Figure 19. Plot of the FK space for the fracture spacing estimated from the Emilio backscattering signals. By taking half of the inverse of the dominant wavenumber or, alternatively, half of the ratio of dominant velocity (2400 m/s from Figure 17) to dominant frequency, a fracture spacing of about 48 to 53 m is obtained.

III.A.3. Additional field data results

We continue to work on two field data sets from fractured carbonate reservoirs provided by our industry sponsors—the offshore Emilio Field data (provided by ENI-AGIP), and an onshore reservoir from the Middle East (provided by Shell). Calibration data in the form of well logs and previous fracture studies are available for both data sets. Some new results (in addition to those presented in the previous sections of this report) are available for both sets of data.

a. Data set 1: Emilio Field

The Emilio Field is a fractured carbonate reservoir located in the Adriatic Sea in about 80m of water. The field is an area of complex folding and faulting at a depth of approximately 2800m. A high quality 3D/4C seismic survey was acquired using ocean bottom cables (OBC). The acquisition parameters were selected to insure excellent azimuthal coverage of the area, making the data ideal for the testing of our methods. Borehole studies suggest the presence of two orthogonal fracture sets oriented ENE and NNW (Angerer et al, 2002). Other studies have also investigated this 3D seismic data using PP and PS wave anisotropy to identify fracture characteristics of the reservoir level (Vetri et al, 2003; Gaiser et al, 2001). In this report we present several new results showing very good agreement between our scattering analysis results and the geologic structure of the field as well as measurements at several well locations. More details are given in Willis et al. (2005b) in Appendix E.

We stacked the near to mid range (< 3500 m) offsets of the preprocessed PP data (Vetri et al, 2003) in eighteen different azimuth orientations from East to West using 20 degree wide overlapping ranges, in 10 degree steps (note that these angle ranges include the corresponding ranges 180 degrees away) This process created eighteen 3D stacked volumes. The transfer functions and scattering indices for the formation zone were computed for each of these stacked volumes (e.g., Willis et al., 2004a, b). The scattering indices were sorted and directions for those with the highest angular contrast in values (in this case for scattering index values greater than 5) were plotted as ‘quivers’ (i.e., short line segments) giving a map view of the location and direction of possible fractures determined by this method (Figure 20). These plots were also shown in previous reports

and papers (e.g., Willis et al., 2003, 2004). The locations of these fracture measurements, however, are taken from stacked data (rather than migrated data), and as such, their locations are in the un-migrated positions. To adjust for this potential mispositioning, we performed a map migration of all the scattering indices with angular contrasts greater than 4. These results are shown as blue quivers in Figure 21. Here we have used the coordinate system of in-lines and cross-lines (rather than Northings and Eastings as in Figure 20) to be able to plot the seismically derived fault system (in black) and well information on the same diagram. The results of this migration process show a very strong correlation between the spatial distribution and orientation of our fracture results and the fault system in the field. We observe that the clusters of the blue quivers (i.e., zones interpreted to contain increased fracture density) tend to congregate around the fault zones, particularly near multiple faults and at fault tips. In addition, we see that the quivers tend to align either parallel or perpendicular to the faulting.

Figure 20. Fracture orientations for the Emilio field from scattering index values showing an angular contrast in values larger than 5.

Faults Derived from Seismic and Scattering Index Fracture Orientation

Figure 21. Map-migrated scattering index fracture directions (in blue) for the Emilio field (having angular contrast values >4). The black lines indicate faults derived from seismic data. The well locations are indicated by the round colored circles.

The left side of Figure 22 shows a rotated version of Figure 21, to align with the Northings and Eastings coordinate system. The right side of Figure 22 is a plot of the scattering directions for all the CDP locations in the survey, without omitting low scattering index values. The scattering index directions have been color-coded using the color legend on the top right of the figure. The intensity of the colors is related to the intensity of the scattering index. Small angular contrasts in the scattering indices (that is, weaker indications of fracturing) are denoted by tinting the color of the corresponding CDP cells toward the center of the color legend wheel (white). Larger angular contrasts (that is, strong indications of fracturing) are tinted toward brighter colors at the edge of the legend color wheel, indicating greater confidence. The green, red, gray and blue colors indicate fracture strikes of East, Northeast, North and Northwest, respectively.

We next compare our fracture directions with those derived by shear wave anisotropy. The left panel of Figure 23 (modified from Figure 10 of Vetri et al, 2003) shows the fracture strike direction derived from the fast direction of the PS waves. We have added three black arrows to help interpret their color scale. In the right panel of

Figure 23 we have taken our fracture directions (from the right panel of Figure 22) and performed modal smoothing of the fracture orientations using a 200x400m box centered about each CDP. As before, we plotted arrows indicating three fracture direction trends. The red, large area in the lower part of the right panel is the most obvious feature. This area indicates a fracture direction of NE, which is identical to the direction indicated by the shear wave data. Close comparison of the figures shows that the directions agree over much of the survey.

Figure 22. A comparison of the map-migrated scattering index fracture orientations (left panel copied and rotated from Figure 21) having high angular contrast values with the scattering index fracture directions for all CDPs which have not been migrated (right panel). The color legend at the top right indicates the fracture direction in hue and increasing angular contrast with intensity.

The final result (Figure 24) compares well-derived fracture orientations with those derived by the scattering index analysis. The top row shows the well information (from Vetri et al., 2003) indicating the direction of horizontal stress maximum (SHmax). In general, fractures align subparallel to the SHmax direction. We added a red arrow to the Well 4 results to emphasize the SHmax direction, since break out directions tend to align in the SHmin direction. The middle row shows close-ups from Figure 21 around these three wells. To further clarify the fracture trends, we histogrammed the map migrated scattering directions around each well and plotted them in rose diagram format in the

bottom row of Figure 24. There is very good agreement between the scattering index orientations and the well-derived fracture orientations at these three wells. The use of the map migration procedure to ensure that the scattering indices are placed in the correct spatial position has improved the comparison with well data, and the apparent relationship between fracture density and geologic faulting, significantly.

Figure 23. The left panel shows the fracture strike derived from PS anisotropy (Vetri et al, 2003) with its corresponding color-coded direction legend at the bottom left. The right panel shows the smoothed fracture orientations derived from the scattering index analysis in right side of Figure 22 with its corresponding color-coded legend at the top right. The black arrows indicate three fracture orientation trends.

b. Data set 2: Onshore fractured carbonate field

The second data set used for testing our method is from an onshore location in the Middle East. The field produces from a gently folded, shallow, fractured carbonate. Production is primarily controlled by fractures oriented in two directions: approximately N50°E (the most important system for fluid flow) and N40°W. The data acquisition used a ‘zipper’ shot configuration (i.e., a zigzag pattern of shot points between receiver lines), with single component (vertical) receivers. Although this acquisition pattern results in the highest fold along the receiver line direction with lower fold in the other azimuthal directions, the fold was adequate to apply our scattering index methods to the data. In

addition to the seismic data we also received access to well log data, including extensive formation microimager (FMI) logs that provide calibration data on fracture orientation.

Figure 24. The top set of diagrams show the well derived fracture information (from Vetri et al., 2003) – SHmax is generally the direction of fracture strike. The red arrow indicates the direction of SHmax for well 4. The middle three diagrams are close-ups of Figure 21 around the corresponding well locations showing the agreement of the map migrated scattering directions with the well fracture directions. The bottom three diagrams show the histograms, in rose diagram format, of the map migrated scattering index directions around each of the wells.

We have processed a swath of data over the center of the field and calculated scattering indices at each CDP location. The data have been rendered as a color plot of all indices using the same approach as shown in Figure 22 for the Emilio data – that is, the intensity of color is related to the level of confidence in the presence of fractures, and the color values are related to the fracture orientation. Figure 25 shows a sequence of plots for several different time intervals in the seismic data volume. The color ‘compass’

shows the color values representing fracture orientation (e.g., red is NE/SW, green is E/W, and blue is NW/SE), and the intensity variations grading from high intensity colors (for high confidence) to white (for no values), with lighter color shades indicating lower confidence levels. The receiver lines were oriented NW/SE, which is reflected in the orientation of the plots. The plots show variations with depth, which supports our contention that the scattering index calculation (because it is a comparative, or differential type analysis method) is insensitive to any overburden or acquisition footprints. Figure 26 shows a time slice at approximately the depth of the reservoir. Superposed on this plot of the scattering indices are plots of FMI data from several wells in the field. The FMI data provide information on the orientation of the fractures measured from the logs in the reservoir interval. The FMI results are color coded using the same colors used for the scattering indices—that is, the fracture orientations from the FMI logs and the seismic scattering can be easily compared. The agreement is very good, providing confidence that these methods can be applied to land seismic data that do not have the ideal azimuthal coverage.

Figure 25. Five time slices from shallow (a) through deep (e) sections of the onshore carbonate seismic data set. The plots show the scattering indices computed at each CDP location. The color value shows the interpreted fracture orientation (e.g., red is NE/SW) and the color intensity shows the level of confidence in the fracture estimate. Note that the results vary with depth.

Fracture Directions From Seismic Scattering And Well Measurements

Figure 26. Comparison of scattering indices with FMI well measurements at the reservoir depth. The FMI data from 8 wells in the field are presented as polar plots showing the strike (location of the points on the plot which are also color coded in the same way as the scattering indices) and dip of fractures (radial position of the points, with horizontal fractures lying at the center of the plots and vertical falling on the outer edge of the circle) in the reservoir interval. The scattering index orientations are very consistent with the FMI results. FMI data also show most fractures to be near vertical.

III.B. Fracture permeability estimation: Flow modeling

As described in previous reports, the Oda-model statistical approach (Oda, 1985; Brown and Bruhn, 1998) provides a promising link from the seismic scattering index analysis to a permeability tensor estimate with appropriate calibration at wells for aperture and length distributions. We will test this approach in the coming months in conjunction with our industry collaborators.

III.C. Borehole dispersion analysis and stress estimation

We are continuing to work on improved methods for the inversion of cross-dipole flexural mode dispersion curve cross over (e.g., Huang et al., 1999; Grandi et al., 2003, Briggs et al., 2003) for estimating in-situ stress variations.

IV. Technology Transfer

We have been actively presenting our results to industry through presentations and publications. During the past six months papers were presented at the EAGE meeting in Madrid and at our annual industry consortium meeting at MIT, which was attended by representatives from 15 companies (both producers and contractors). Papers have also been submitted to Geophysics and the SEG meeting in Houston (to be held in November 2005). We are arranging to test these methods on other data sets from field sites in the US and Canada in the coming months.

V. Conclusions

We are entering the final phases of the project. Our methods for estimating fracture orientation, fracture spacing, and fracture density from the seismic scattering signals have been tested with numerical modeling data and field data from two different fields. The results have been validated against well log measurements, other seismic analysis methods, and existing geologic models of the fields. Based on these comparisons, the methods appear to be robust and accurate. The next step is to use these seismically-derived fracture parameters as the basis for improving our input into flow models. We will approach this phase in collaboration with our industry partners.

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APPENDIX A

Comparison of Discrete Fracture and Effective Media Representation of Fractures on Azimuthal AVO

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Abstract

In fractured reservoir development, azimuthal AVO (AVOaz) properties of reflected PP waves from reservoir tops are often used to infer fracture properties. The fracture parameter inversion is based on either an effective media model (EMM) or a discrete fracture model (DFM). We address the differences in fracture properties that may be inferred by AVOaz based on the two models. For the DFM we focus on fractures whose length and spacing are comparable to the seismic wavelength. First, we compute the elastic parameters describing the fractured reservoir for each type of model. Then we synthesize seismic data using a finite-difference program for both sets of elastic parameters. By performing AVOaz analysis, we find that EMM and DFM predict different offsets for maximum AVOaz magnitudes. The DFM results show larger AVOaz magnitude with farther offsets, and phase changes at offsets larger than 35 degrees may indicate compliant fractures in a reservoir. For compliant fractures, the fracture strike determined using AVOaz effect based on the EMM is opposite to that from the DFM. This difference could cause incorrect estimation of fracture orientation if the EMM is used to interpret data from a reservoir with discrete fracture zones. DFM may be better suited for modeling wavelength-scale fractures.

1. Introduction

Geophysicists commonly use effective media theory to interpret the seismic amplitude and velocity variations with azimuth and offset for formations with vertically aligned fractures (e.g., Lynn, 2004). The azimuthal AVO (AVOaz) properties of reflected PP waves have been used to identify fracture orientation (e.g. Shen et al., 2002). However, the effective media model (EMM) is only valid for media with fractures that are small relative to the seismic wavelength (e.g., Lynn, 2004, Liu et al., 2000). For fractures whose lengths are comparable to seismic wavelength, discrete fracture models (DFM) are more realistic (Coates and Schoenberg, 1995). Willis et al. (2004) used the DFM and scattered seismic energy to determine spatial orientation and distribution of reservoir fractures. They applied their method to synthetic and field data and showed results consistent with log data. They computed their synthetic data using DFM. Until recently, most work on AVOaz analysis has been based on EMM, which suggests that many small evenly distributed cracks can have an important effect on seismic reflections from the top of a fractured reservoir. For more isolated discrete fractures or fracture zones distributed with spacing on the order of a seismic wavelength, however, conventional wisdom suggests that there would be very little effect on the PP reflection from the top of the

reservoir and most of the effect would be visible later in the trace due to scattering. The purpose of this paper is to give some thoughts on how discrete fractures can have impact on AVOaz analysis for PP reflections from the top of the fractured reservoir. In addition to the utility of the scattered energy from discrete fractures for reservoir characterization, the AVOaz from the top of the reservoir also carries valuable information. Because these discrete fractures are important factors in controlling fluid flow and production, we should use all possible interpretive tools to characterize their properties. In this study, we compare the AVOaz characteristics of a fractured medium described by (1) small scale distributed fractures (EMM) and (2) larger scale discrete fractures (DFM). We use finite difference modeling to calculate the synthetic seismograms.

2. Model

We generate the 3-D full-azimuth, synthetic seismograms using elastic, anisotropic finite-difference calculations. The finite-difference code uses a rotated staggered grid (RSG) (Saenger, 2004). The RSG method can represent accurately large contrasts of elastic moduli between the fractures and surrounding formation. We also apply the perfectly matched layer (PML) absorbing boundary condition to minimize boundary reflections (Marcinkovich and Olsen, 2003). Figure 1 shows the schematics of the model: the properties of the top and bottom layers are $V_p = 2460$ m/s, $V_s = 1230$ m/s, and density = 2300 kg/m^3 , while the fractured layer is 100 meter thick and the background properties are $V_p = 3300$ m/s, $V_s = 1800$ m/s, and density = 2200 kg/m^3 . The difference between the configuration of fractures in the EMM and DFM is shown in Figure 2. In the EMM, small cracks or fractures are evenly distributed within the fractured layer, but in the DFM small cracks are assumed to cluster onto discrete fracture zones that are distributed in the layer. In the DFM the formation is homogeneous and unfractured between the discrete fracture zones. We assume the same crack density, aperture, and fluid inclusion throughout the layer for the EMM case and in each fracture zone for the DFM. The total fractured layer in the EMM and each discrete fracture in DFM can be represented as an equivalent transversely isotropic medium with a horizontal symmetry axis. In the limit as the fracture spacing goes to zero the DFM and EMM would have identical properties. For the EMM, we use the method of Liu et al. (2000) to calculate the medium properties. For DFM, we compute the elastic constants using the method of Coates and Schoenberg (1995). For the DFM we create four different fracture spacing models: 20m, 30m, 40m, and 50m. For all models we use a 40 Hz Ricker wavelet for the source (with a nominal P wavelength of 66m and S wavelength of 30 m), and assume that the fractures are filled with gas and the tangential and normal compliances (Z_t and Z_n) are of the same order. The tangential and normal compliances of the fractures are: for compliant fractures, $Z_t = 4.04 \times 10^{-10}$ m/Pa, $Z_n = 3.46 \times 10^{-10}$ m/Pa, and for stiff fractures, $Z_t = 8.67 \times 10^{-11}$ m/Pa, $Z_n = 7.42 \times 10^{-11}$ m/Pa. Figure 3 shows the synthetic seismograms parallel and perpendicular to the fracture strike for the DFM and EMM. Note that the DFM results in a complicated section with the seismic energy scattered from and between individual fractures.

3. AVO Analysis

We analyze the AVOaz perpendicular (defined as 0 degree) and parallel (defined as 90 degrees) to the fracture strike for both the EMM and DFM synthetics. We first window the PP reflection from the top of the reservoir, and then pick the maximum amplitude in each window for each azimuth over a range of offsets. Figure 4 shows the comparison of AVOaz perpendicular and parallel to the compliant fracture strike for the EMM and DFM. Figure 5 shows the same comparison for stiff fractures. We then study the AVOaz magnitude by subtracting the absolute values of amplitudes in the perpendicular and parallel directions and then taking the absolute values of the difference. We then normalize the difference values by the sum of the parallel and perpendicular amplitudes. Figure 6 shows the normalized differences of AVOaz magnitudes for the compliant fractures while Figure 7 shows the same plots for the stiff fractures. Finally, we analyze the AVOaz every 15 degrees from perpendicular to parallel to the fracture strike using DFM synthetics (Figure 8 and 9).

4. Discussion

4.1 AVOaz comparison

Even when the fracture spacing is comparable to the seismic wavelength, we observe the effect of discrete fractures on the seismic amplitude of PP reflection from the top of the reservoir. From the AVOaz obtained from the EMM (Figure 6 and 7), we see that the maximum AVOaz effect of fractures is at offsets (angle of incidence) of about 35 degrees. However, the AVOaz obtained from the DFM becomes more prominent as offset increases from 30 to 45 degrees (Figure 6 and 7), especially for compliant fractures. For stiff fractures, though the contrast between fractures and background medium is small, we still observe the effect.

Based on the differences between the EMM and the DFM results, it is clear that the type of model assumed for the subsurface will play a very important role in the interpreted fracture properties. If the fractures are distributed as discrete zones, but we try using an effective media model to invert for the fracture properties such as crack density, we might get a very low average crack density in the whole fractured layer. Actually, the crack density in each single fracture in this case would be much higher than the inversion estimate. Such low estimates could incorrectly bias our interpretation of the reservoir fluid flow capacity.

When we look at the AVOaz behavior for the DFM in more detail (Figure 8), we also observe a phase change at offsets (incidence angles) larger than 35 degrees for compliant fractures. The offset at which the phase change occurs also varies with fracture spacing and azimuth. But for stiff fractures, no phase change is observed (Figure 9). Such phase changes, with proper calibration, could provide a means for characterizing fracture compliance.

4.2 AVOaz in directions perpendicular and parallel to fracture strike

For the DFM, we observe that the amplitude in the direction perpendicular to the compliant fracture strike (0 degree) is smaller than that in the parallel direction (90 degrees) (Figure 4). However, for the EMM, the opposite trend is seen for middle to far offsets. But for stiff fractures, the EMM and DFM show the same trend of AVOaz, that is amplitudes increase from 0 to 90 degrees (Figure 5). These results again point out that the choice of model is critical in interpreting any measured field data. For the compliant fracture synthetic data (Figure 4), very different fracture orientation estimates would result if we used the incorrect model type.

Another observation is that the AVOaz magnitude predicted by the DFM is larger than that of the EMM for offsets larger than 40 degrees for compliant fractures with spacings greater than 20m (Figure 6). Lynn (2004b) has observed that in the analysis of field data the AVOaz magnitude is usually much larger than theoretical prediction by EMM. She suggests that this effect could be the result of larger scale fractures. Our synthetic results provide some support to that hypothesis.

For the DFM, we also see that the fracture spacing affects the AVOaz magnitude. The larger the spacing is, the smaller the magnitude at the same offset (Figure 4). This is a direct result of the model definition. As mentioned previously, the crack density is the same for the entire reservoir in the EMM and within each discrete fracture zone in the DFM. As the fracture spacing decreases, the DFM approaches the EMM. In the limit of zero spacing the two models would be equivalent.

Finally, the AVOaz magnitude gradually increases with azimuth for the DFM results (Figure 8 and 9). We find AVOaz from far offset data are more sensitive to fracture properties, such as compliance and spacing.

5. Conclusion

We compare the AVOaz magnitudes using effective media (EMM) and discrete fracture (DFM) models. We assume that the crack properties are the same for both models, with the cracks distributed throughout the fractured layer for the EMM and clustering on discrete single fracture zones for the DFM. For the DFM fracture lengths and spacings are comparable to the seismic wavelength. Based on synthetic waveforms generated by finite difference calculations we see that the AVOaz of the PP reflection from the top of a fractured reservoir is affected differently by distributed and discrete fracture distributions. Results from EMM show that around 30 degrees offset the magnitude of AVOaz is a maximum, but the DFM results show larger AVOaz magnitude with farther offsets. Fracture orientation extracted from AVOaz based on the EMM and DFM could differ by 90 degrees for compliant fractures. In the model of compliant fractures we also observe phase changes at offsets larger than 35 degrees.

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Figure 1: Vertically fractured reservoir embedded in two homogeneous half-spaces.

Figure 2: Configuration of fractures in the EMM and DFM. EMM: small cracks evenly distributed within the layer form an effective HTI media; DFM: single fractures composed of small cracks with the same properties as the EMM, such as crack density, aperture and fluid inclusions, discretely distributed with spacing comparable to seismic wavelength.

(a)

(b)

Figure 3: Synthetic shot records for (a) the discrete fracture model with 30 meter spacing and (b) the effective media model.

Figure 4: Comparison of AVOaz in directions perpendicular and parallel to the strike of compliant fractures based on EMM and DFM.

Figure 5: Comparison of AVOaz in directions perpendicular and parallel to the strike of stiff fractures based on EMM and DFM.

Figure 6: The normalized AVOaz magnitude difference (perpendicular – parallel) for compliant fractures.

Figure 7: The normalized AVOaz magnitude difference (perpendicular – parallel) for stiff fractures.

Figure 8: AVOaz from 0 to 90 degrees for compliant fractures based on DFM. The blue lines are AVO for each 15 degrees from 0 to 90 degrees. Phase changes occur at far offsets for fracture spacings of 20 and 30 m.

Figure 9: AVOaz from 0 to 90 degrees for stiff fractures based on DFM. The blue lines are AVO for each 15 degrees from 0 to 90 degrees. No phase changes occur at far offsets for any fracture spacing.

APPENDIX B

A Short Note on Modeling Wave Propagation in Media with Multiple Sets of Fractures

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Abstract

Wave propagation and scattering in fractured formations have been modeled with finite-difference programs and the use of equivalent anisotropic media description of discrete fractures. This type of fracture description allows a decomposition of the compliance matrix into two parts: one accounts for the background medium and another accounts for the fractures. The compliance for the fractures themselves can be a sum of compliances of various fracture sets with arbitrary orientations. Non-orthogonality of the fractures, however, complicates the compliance matrix. At the moment, we can model an orthorhombic medium (9 independent elastic constants) with the two orthogonal fracture sets. However, if the fractures are non-orthogonal, this results in more general anisotropy (monoclinic) for which we need to specify 11 independent parameters.. Theoretical formulation shows that the finite difference program can be extended to simulate wave propagation in monoclinic media with little additional computational and storage cost.

1. Introduction

Fractures control fluid flow in hydrocarbon reservoirs. Knowledge of the direction, separation and dimensions of fractures is very important in developing reservoir production and stimulation programs. For this reason, characterization of fractures has gained increasing interest over the last decade or so. Fractures are often studied using AVO/AVA analysis. In these studies it is assumed that closely spaced, aligned fractures result in effective anisotropy.

More recently, one begins to consider the effect of discrete fractures on recorded signals. In particular, one group at ERL focuses on developing methods that estimate fracture parameters from waves scattered off the fractures (Willis et al., 2004). To understand the response from discrete fractures, Pearce et al. (2003) used an elastic finite difference scheme developed by Lawrence Berkeley National Laboratory (Nihei et al., 2002). This code implements the Coates-Schoenberg equivalent anisotropic medium approach for fractures (Coates and Schoenberg, 1995). We also developed a similar finite difference program (ERLSMP) that has more functions and a user-friendly interface to simulate the wave propagation in fractured media.

The Coates-Schoenberg formulation is quite general as it allows for modeling multiple intersecting sets of fractures with arbitrary orientations. However, in order to fully benefit from this flexibility, the finite-difference code should allow for fairly arbitrary anisotropy (at least monoclinic).

In this note, we review briefly the method developed by Coates and Schoenberg (1995) and Hood (1991). Then we discuss how to compute the equivalent stiffness matrices of fractured media in various scenarios, and detail the formulation of modeling wave propagation in media with non-orthogonal fracture sets.

2. Modeling Discrete Fractures

For a system of aligned cracks, or fractures, an effective anisotropic medium can be derived when the dominant wavelength is long compared to the typical scales of the fractures (like width and spacing). This long-wavelength equivalent medium theory was used by Schoenberg and Muir (1989) to derive the effective properties of a finely layered medium.

To accurately model the response of seismic waves through boundaries in an elastic solid, Muir et al. (1992) used the idea of Schoenberg and Muir (1989) to represent stiffness (or compliance) coefficients in a grid cell traversed by a fracture that is in some way the 'average' of a stack of parallel layers. Later yet, Coates and Schoenberg (1995) used the same idea together with a linear slip model for the boundary to implement discrete or single fracture(s) in a finite difference scheme. The Coates-Schoenberg method has been used since by several researchers to understand scattering off discrete fractures (see Coates and Schoenberg, 1995, Nihei et al., 2002 and Vlastos et al., 2003, for example).

Pearce et al. (2003) used the same formulation to model the response of a set of parallel vertical fractures as a simplified model of a fractured reservoir. The fracture is modeled as an interface across which the traction is continuous, but the displacement jumps. This can be expressed by the slip interface condition (Coates and Schoenberg, 1995).

As pointed out by Coates and Schoenberg (1995), this approach can be implemented in a fairly straightforward manner when the fracture is aligned with the finite difference grid. However, this is not so simple for fractures making an angle with respect to the FD grid. Additional difficulty occurs when one fracture is cut by another fracture. Nichols et al. (1989) described the problem of modeling rocks with multiple sets of fractures based on the theory outlined by Schoenberg and Muir (1989). They also showed explicitly how to obtain the resultant compliance tensor for an orthogonal fracture set embedded in an isotropic medium. They showed that such a fracture set renders the medium orthorhombic.

Now, in the formulation of Coates and Schoenberg (1995), the fractures are not required to be parallel to the finite difference grid. Even with two sets of parallel fractures, the grid can be rotated, such that the stiffness tensor corresponds to one of an orthorhombic medium. However, if the fractures are not orthogonal, it is impossible to rotate the grid such that the medium becomes orthorhombic. One always has a monoclinic medium, which is characterized by 13 elastic parameters. On account of constraints imposed by the vertical fractures, this number can be reduced to 11

(Schoenberg, 1998).

3. Case studies for Fracture Representation

3.1. A vertical fracture embedded in an isotropic medium with fracture strike parallel to the finite difference grid

For a transverse isotropic medium with a horizontal symmetry axis (HTI), the stiffness matrix can be written as:

$$C = \begin{bmatrix} c_{11} & c_{12} & c_{13} & & & \\ c_{12} & c_{11} & c_{13} & & & \\ c_{13} & c_{13} & c_{33} & & & \\ & & & c_{44} & & \\ & & & & c_{44} & \\ & & & & & c_{66} \end{bmatrix}, \quad (1)$$

where $c_{12} = c_{11} - 2c_{66}$ and only five elastic constants are independent.

Figure 1. A vertical fracture embeds in a homogenous background formation. The normal and strike directions of the fracture are parallel to the finite difference grid.

For vertical discrete fractures embedded in a homogenous background formation (Figure 1), Coates and Schoenberg (1995) showed that the equivalent medium in the fracture coordinate system (x - y system) possesses the property as an HTI medium. Axes x and y are normal and parallel to the fracture strike. Figure 1 shows that in a 2-D finite difference cell with area A , the fracture length is l and the thickness of the fracture is h . In 3-D, A is replaced by V , the volume of the cell, and l is replaced by a , the area of the fault or fracture lying within the 3-D cell volume.

Define

$L = \frac{l}{A}$ for 2-D and $L = \frac{a}{V}$ for 3-D.

The explicit expression of the equivalent medium stiffness matrix can be written as

$$C = \begin{bmatrix} (\lambda + 2\mu)(1 - r^2\delta_N) & \lambda(1 - r\delta_N) & \lambda(1 - \delta_N) & & & \\ \lambda(1 - r\delta_N) & (\lambda + 2\mu)(1 - r^2\delta_N) & \lambda(1 - \delta_N) & & & \\ \lambda(1 - \delta_N) & \lambda(1 - \delta_N) & (\lambda + 2\mu)(1 - \delta_N) & & & \\ & & & \mu(1 - \delta_T) & & \\ & & & & \mu(1 - \delta_T) & \\ & & & & & \mu\delta_N \end{bmatrix} \quad (2)$$

where

$r = \frac{\lambda}{\lambda + 2\mu}$, $\delta_T = \frac{Z_T\mu}{L + Z_T\mu}$, $\delta_N = \frac{Z_N(\lambda + 2\mu)}{L + Z_N(\lambda + 2\mu)}$, and Z_T and Z_N are the tangential and normal compliances of the fracture.

Comparing to equations (1) and (2), we can see that when the finite difference grids are parallel to the fracture coordinate system, the effect of the fracture on wave propagation can be simulated using an equivalent HTI medium.

3.2. A vertical fracture embedded in an isotropic medium with fracture strike making an angle with the finite difference grid

Figure 2. A fracture embeds in a homogeneous background medium. The y axis of the fracture coordinates makes an angle with the y' axis of the finite difference grid coordinates

If the fracture strike makes an angle α to the grid coordinate system (Figure 2), we need to rotate the stiffness matrix for the HTI medium using the Bond transformation (Auld, 1990). The stiffness matrix C has 13 non-zero elements and shows monoclinic symmetry:

$$C = \begin{bmatrix} c_{11} & c_{12} & c_{13} & 0 & 0 & c_{16} \\ c_{12} & c_{22} & c_{23} & 0 & 0 & c_{26} \\ c_{13} & c_{23} & c_{33} & 0 & 0 & c_{36} \\ 0 & 0 & 0 & c_{44} & c_{45} & 0 \\ 0 & 0 & 0 & c_{45} & c_{55} & 0 \\ c_{16} & c_{26} & c_{36} & 0 & 0 & c_{66} \end{bmatrix}. \quad (3)$$

3.3. Multiple sets of non-orthogonal vertical fractures

Figure 3. Non-orthogonal fractures embed in a homogeneous background medium.

For multiple sets of non-orthogonal vertical fractures (Figure 3), Nichols et al. (1989) show that the compliance matrix for the equivalent medium is

$$S = S_b + \sum_{i=1}^m \Delta S_i \quad (4)$$

where m is the number of fracture sets, S_b and ΔS_i are the compliance of background medium and contribution from each fracture set i . It is obvious that the order in which the fractures are included does not affect the final compliance. Assuming each fracture strike forms an angle α to the finite difference grid direction, the Bond transformation matrix can be written as

$$B = \begin{bmatrix} \frac{1 + \cos 2\theta_i}{2} & \frac{1 - \cos 2\theta_i}{2} & 0 & 0 & 0 & \sin 2\theta_i \\ -\frac{\sin 2\theta_i}{2} & \frac{\sin 2\theta_i}{2} & 0 & 0 & 0 & \cos 2\theta_i \\ 0 & 0 & 0 & -\sin \theta_i & -\cos \theta_i & 0 \end{bmatrix}, \quad (5)$$

and

$$\Delta S_i = B^T Z_i B, \quad (6)$$

where in fracture coordinate system, the compliance of each fracture set can be written as

$$Z_i = \begin{bmatrix} Z_{Ni} & & \\ & Z_{Vi} & \\ & & Z_{Hi} \end{bmatrix}, \quad (7)$$

where Z_{Ni} , Z_{Vi} , and Z_{Hi} represent the normal, vertical and horizontal compliance of the fracture, respectively.

Inversion of the compliance matrix gives the stiffness matrix. Such fractured media show monoclinic symmetry. The constitutive equation can be written as:

$$\begin{bmatrix} \tau_{11} \\ \tau_{22} \\ \tau_{33} \\ \tau_{23} \\ \tau_{13} \\ \tau_{12} \end{bmatrix} = \begin{bmatrix} c_{11} & c_{12} & c_{13} & 0 & 0 & c_{16} \\ c_{12} & c_{22} & c_{23} & 0 & 0 & c_{26} \\ c_{13} & c_{23} & c_{33} & 0 & 0 & c_{36} \\ 0 & 0 & 0 & c_{44} & c_{45} & 0 \\ 0 & 0 & 0 & c_{45} & c_{55} & 0 \\ c_{16} & c_{26} & c_{36} & 0 & 0 & c_{66} \end{bmatrix} \begin{bmatrix} \varepsilon_{11} \\ \varepsilon_{22} \\ \varepsilon_{33} \\ 2\varepsilon_{23} \\ 2\varepsilon_{13} \\ 2\varepsilon_{12} \end{bmatrix}. \quad (8)$$

The stiffness matrix has 13 elastic constants, but 11 of them are independent due to the constraints of vertical fractures.

3.4. Two orthogonal sets of fractures embedded in an isotropic background medium

As a special case, an isotropic background medium embedded with two orthogonal sets of fractures can be described by an orthorhombic elastic stiffness matrix. This conclusion can be deduced from the more general case 3 by choosing θ_i be 0 and 90 degrees. The orthorhombic elastic stiffness matrix can be written as follows:

$$C = \begin{bmatrix} c_{11} & c_{12} & c_{13} & 0 & 0 & 0 \\ c_{12} & c_{22} & c_{23} & 0 & 0 & 0 \\ c_{13} & c_{23} & c_{33} & 0 & 0 & 0 \\ 0 & 0 & 0 & c_{44} & 0 & 0 \\ 0 & 0 & 0 & 0 & c_{55} & 0 \\ 0 & 0 & 0 & 0 & 0 & c_{66} \end{bmatrix} \quad (9)$$

Figure 4. Two orthogonal sets of fractures embedded in an isotropic background medium is equivalent to an orthorhombic medium

3.5. A vertical fracture imbedded in a TI medium

In fact, the background medium can be arbitrary anisotropic for describing the fractures using equivalent media approaches (Nicols et al, 1989, Hood, 1991). A special scenario of interests is a set of vertical fracture imbedded in a layered TI medium, which is equivalent to an orthorhombic medium by Schoenberg and Helbig (1997). We represent a layered medium (transversely isotropic media with a vertical symmetric axis) as:

$$C = \begin{bmatrix} c_{11} & c_{12} & c_{13} & 0 & 0 & 0 \\ c_{12} & c_{11} & c_{13} & 0 & 0 & 0 \\ c_{13} & c_{13} & c_{33} & 0 & 0 & 0 \\ 0 & 0 & 0 & c_{44} & 0 & 0 \\ 0 & 0 & 0 & 0 & c_{44} & 0 \\ 0 & 0 & 0 & 0 & 0 & c_{66} \end{bmatrix}. \quad (10)$$

Using the just mentioned method, we write the stiffness matrix of the equivalent medium as:

$$C = \begin{bmatrix} c_{11}(1-\delta_N) & c_{12}(1-\delta_N) & c_{13}(1-\delta_N) & 0 & 0 & 0 \\ c_{12}(1-\delta_N) & c_{11}\left(1-\delta_N\frac{c_{12}^2}{c_{11}^2}\right) & c_{13}\left(1-\delta_N\frac{c_{12}}{c_{11}}\right) & 0 & 0 & 0 \\ c_{13}(1-\delta_N) & c_{13}\left(1-\delta_N\frac{c_{12}}{c_{11}}\right) & c_{33}\left(1-\delta_N\frac{c_{13}^2}{c_{11}c_{13}}\right) & 0 & 0 & 0 \\ 0 & 0 & 0 & c_{44} & 0 & 0 \\ 0 & 0 & 0 & 0 & c_{44}(1-\delta_V) & 0 \\ 0 & 0 & 0 & 0 & 0 & c_{66}(1-\delta_H) \end{bmatrix} \quad (11)$$

where

$$\delta_N = \frac{Z_N \rho c_{11}}{1 + Z_N \rho c_{11}}, \quad \delta_V = \frac{Z_V \rho c_{44}}{1 + Z_V \rho c_{44}}, \quad \text{and} \quad \delta_H = \frac{Z_H \rho c_{66}}{1 + Z_H \rho c_{66}}.$$

We assume the x axis of the TI media is normal to the fracture.

4. Finite Difference Implementation

We use the constitutive equation for orthorhombic media for our finite difference program. In implementation, we apply time differentiation to both sides the of constitutive equation, written out explicitly as:

$$\begin{aligned} \frac{\partial \tau_{xx}}{\partial t} &= c_{11} \frac{\partial v_x}{\partial x} + c_{12} \frac{\partial v_y}{\partial y} + c_{13} \frac{\partial v_z}{\partial z}, \\ \frac{\partial \tau_{yy}}{\partial t} &= c_{12} \frac{\partial v_x}{\partial x} + c_{22} \frac{\partial v_y}{\partial y} + c_{23} \frac{\partial v_z}{\partial z}, \\ \frac{\partial \tau_{zz}}{\partial t} &= c_{13} \frac{\partial v_x}{\partial x} + c_{23} \frac{\partial v_y}{\partial y} + c_{33} \frac{\partial v_z}{\partial z}, \\ \frac{\partial \tau_{yz}}{\partial t} &= c_{44} \left(\frac{\partial v_y}{\partial z} + \frac{\partial v_z}{\partial y} \right), \\ \frac{\partial \tau_{xz}}{\partial t} &= c_{55} \left(\frac{\partial v_x}{\partial z} + \frac{\partial v_z}{\partial x} \right), \\ \frac{\partial \tau_{xy}}{\partial t} &= c_{66} \left(\frac{\partial v_y}{\partial x} + \frac{\partial v_x}{\partial y} \right), \end{aligned} \quad (12)$$

where τ_{ij} and v_i are elements of the stress tensor and velocity, respectively, and $i, j = x, y, z$.

To model non-orthogonal sets of fractures (monoclinic equivalent media), we need to extend equation (12) to the following:

$$\frac{\partial \tau_{xx}}{\partial t} = c_{11} \frac{\partial v_x}{\partial x} + c_{12} \frac{\partial v_y}{\partial y} + c_{13} \frac{\partial v_z}{\partial z} + c_{16} \left(\frac{\partial v_y}{\partial x} + \frac{\partial v_x}{\partial y} \right),$$

$$\begin{aligned}
\frac{\partial \tau_{yy}}{\partial t} &= c_{12} \frac{\partial v_x}{\partial x} + c_{22} \frac{\partial v_y}{\partial y} + c_{23} \frac{\partial v_z}{\partial z} + c_{26} \left(\frac{\partial v_y}{\partial x} + \frac{\partial v_x}{\partial y} \right), \\
\frac{\partial \tau_{zz}}{\partial t} &= c_{13} \frac{\partial v_x}{\partial x} + c_{23} \frac{\partial v_y}{\partial y} + c_{33} \frac{\partial v_z}{\partial z} + c_{36} \left(\frac{\partial v_y}{\partial x} + \frac{\partial v_x}{\partial y} \right), \\
\frac{\partial \tau_{yz}}{\partial t} &= c_{44} \left(\frac{\partial v_y}{\partial z} + \frac{\partial v_z}{\partial y} \right) + c_{45} \left(\frac{\partial v_x}{\partial z} + \frac{\partial v_z}{\partial x} \right), \\
\frac{\partial \tau_{xz}}{\partial t} &= c_{55} \left(\frac{\partial v_x}{\partial z} + \frac{\partial v_z}{\partial x} \right) + c_{45} \left(\frac{\partial v_y}{\partial z} + \frac{\partial v_z}{\partial y} \right), \\
\frac{\partial \tau_{xy}}{\partial t} &= c_{66} \left(\frac{\partial v_y}{\partial x} + \frac{\partial v_x}{\partial y} \right) + c_{16} \frac{\partial v_x}{\partial x} + c_{26} \frac{\partial v_y}{\partial y} + c_{36} \frac{\partial v_z}{\partial z}.
\end{aligned} \tag{13}$$

Comparing equation (12) and (13), we find that we can model wave propagation non-orthogonal fracture systems using the finite difference method without technical difficulty. We only need to take into account the additional terms in equation (13). This will only increase the memory storage of the extra elastic constants, but no additional differentiation computation is needed.

5. Conclusion

We summarize and clarify the approaches to represent discrete fractures embedded in background media. Our current finite difference code can model orthogonal sets of fractures, and the algorithm can be efficiently extended to study non-orthogonal sets of fractures. This will result in a small increase in the memory storage and computation.

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APPENDIX C

Fracture Spacing and Orientation Estimation from Spectral Analyses of Azimuth Stacks

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Abstract

Discrete, vertically aligned fracture systems impart one or more notches in the spectral ratios of stacked reflected seismic traces. This apparent attenuation is due to the azimuth dependant scattering introduced by the fractures. The most prominent notch is located at the frequency where the P wavelength is about twice the fracture spacing. The frequency location of the notches can be used to determine the fracture spacings. Azimuth stacks with an orientation parallel to the fractures tend not show these spectral notches – allowing for another way to detect the fracture orientation. An analysis of the vertical component of the 3D, ocean bottom cable seismic survey data from the Emilio field, offshore Italy, shows a prominent set of fractures with a spacing of about 30 to 40 meters with orientations that agree with previous studies.

1. Introduction

There is a large body of the literature devoted to analyzing rocks with fracture sizes and spacings which are much less than one wavelength. For these systems the rock will behave elastically as an effective anisotropic medium displaying the aggregate properties of a distribution of small fractures. Lynn (2004a) gives a good summary of the differences between effective medium and discrete fractures.

Much of our recent work has been devoted to deriving fracture properties from vertical sets of discrete fractures which have dimensions and spacings on the order of the seismic wavelength (e.g. Willis et al, 2004a and 2004b). This study first derives spectral characteristics of azimuth stacks from modeled fractured systems and then applies these observations to seismic field data.

2. Model Study – the Spectral Notch Method

We first analyze the surface seismic reflection traces created from a 3D, anisotropic finite difference algorithm. The models consist of a sandwich of five layers, as shown in

Figure 1. The center layer is an isotropic reservoir containing discrete sets of gas-filled, vertical fractures represented by vertical planes made up of a single grid cell, with equivalent anisotropic medium properties determined using the method of Coates and Schoenberg (1995). We use models with different regular fracture spacings of 100m, 50m, 35m and one with a Gaussian distribution of fractures centered about 35m.

We create azimuth stacks of the shot records at 10 degree increments from normal to parallel to the fractures. As in our previous studies, we find that scattered energy from the fractures is reinforced on the stacks parallel to the fractures and is reduced in the direction normal to the fractures. The left panel in Figure 2 shows the azimuth stacks for the 50m fracture spacing case.

From these azimuth stacks we create their associated transfer functions, as described by Willis et al. (2004). Briefly, this process entails for each azimuth stack trace: 1) identifying a target depth range (the fractured layer) to investigate 2) extracting a window of data containing reflections which are above this fractured layer (denoted as the input), 3) extracting a window of data below the fractured layer (denoted as the output) containing reflections which includes the scattered energy, 4) taking the autocorrelation of the extracted windows, 5) windowing the autocorrelations to focus on the source wavelet near zero lag and 6) computing the spectra ratio of the lower and upper windowed autocorrelations from the amplitude spectrum of the time domain transfer function (see Willis et al, 2004). The right panel in Figure 2 shows the time domain transfer functions for the 50m fracture case. The mean of corresponding amplitude spectra of the 50m case for azimuths within 40 degrees of normal to fracture strike is shown in Figure 3.

Figure 1. Model geometry – five layers with the center layer containing discrete vertical fractures.

Figure 2. Left panel shows the azimuth stacks for the 50m regularly spaced fracture model. The two highlighted areas show the input (left most) and output (right most) windows used to compute the associated transfer functions in corresponding traces in the right panel.

On this display a deep notch in the spectrum at about 35 Hz can be seen. Since there is no attenuation in the model we would expect to see a nearly flat spectral ratio over the bandwidth of about 10 to 80 Hz. This is not the case. At this particular frequency energy in the propagating signal happens to cancel out due to the time delay of a P wave traveling between two fractures and creating a null. The notch at about twice the fracture spacing is characteristic of all the models studied.

To further study this notch, we convert the frequency axis to a normalized scale, n , using the relationship $n = V_p / (\text{Frequency} * \text{Fracture Spacing})$ where V_p is the average P-wave velocity in the depth range of investigation. Figure 4 shows the mean spectral ratios for all the models studied using this normalized scale. Here we see the presence of a notch in each of the spectra at the normalized wavelength of about 1.5 to 2. Higher order notches are present, but do not appear at the same place.

Figure 3. The mean of the spectral ratios for the 50m fracture case for azimuth stacks with orientations within 40 degrees of normal to the fracture strike. The vertical axis is in dB.

Figure 4. The spectral ratio plots for all four models. Each spectrum is the mean of the spectra within 40 degrees of normal to the fracture strike.

In Figures 3 and 4 we have shown averages of the spectra using the azimuths within 40 degrees of the normal to the fracture strike. We excluded the spectral ratios in the remaining directions as the notch effect is reduced close to the fracture strike direction. This is due to the fractures acting like mechanical polarizers, channeling energy away from the normal direction, towards the parallel direction. Hence, in the parallel direction, there is in fact an amplification, or a peak in the spectral ratios. Thus, this azimuth sensitive behavior of the spectral ratios also provides fracture orientation. Lynn (2004b) has noted holes in the spectra shear components and attributed them to interference of backscattered energy.

3. Emilio Field Data Study

In 2000, a 3D/4C seismic survey was collected over the Emilio Field, located in the central part of the Adriatic Sea, near the eastern coast of Italy. The reservoir unit is a fractured carbonate with two orthogonal fracture sets oriented ENE and NNW (Angerer et al, 2002). This field has been investigated using PP and PS wave anisotropy to identify fracture characteristics of the reservoir level (Minsley et al, 2004; Vetri et al, 2003; Gaiser et al, 2002).

We apply the spectral notch method, described above for the model data, to analyze the seismic data from the Emilio field. We selected the near to mid range offsets of the preprocessed PP data (Vetri et al, 2003) and created eighteen different azimuth stack volumes from East to West using 20 degree wide overlapping ranges. We created two superbins to collect the stacked traces around wells 4 and 8. The size of each superbin was 11x11 bins (125m x 250m). For each of the 18 azimuth stacks, the traces which fell within the two bins were collected. For each of these traces, a time window above, and another window below the reservoir were extracted and their autocorrelations computed.

While the time domain transfer function could be computed as an intermediate step using Weiner deconvolution, we directly computed the spectral ratios by spectral division of the fast Fourier transforms of the autocorrelations. We then averaged the spectral ratio values for all the traces with the same azimuth stack direction within the same superbin.

It should be noted that the signal-to-noise level in the data will dictate the viable frequency bandwidth, which in combination with P velocity of the layers under consideration defines an observable range of wavelengths and consequently fracture spacings for a given data set. For the current data set, observable fracture spacings are expected to be in the range 20 to 120 m.

Fig 5 shows the spectral ratio amplitudes as a function of azimuth and wavelength for well 4 (left) and 8 (right). The vertical axis shows each of the 18 azimuths from 0 degrees East, 90 degrees North and 170 degrees nearly West. Clearly evident on the figure is a significant azimuth variation of spectral ratio amplitudes. Further, prominent notches (blue) across a broad range of azimuths can be observed, particularly at fracture spacings of about 30m. From the model study, the notches are expected over a range of azimuths that are nearly perpendicular to the fracture direction. Additional features are

the peaks (red) in both plots. Well 4 shows large amplitudes at about 70 and 120 degrees. Well 8 shows a band of large amplitudes at a range of azimuths from about 90 to 120 degrees. These larger amplitudes occur at spacings of 50 to 60 m, and are expected indicate directions that are close to the fracture strike directions. Thus the peaks and troughs are expected over perpendicular azimuths if only a single, equally spaced fracture set is present.

Figure 5. Spectral ratio functions for well 4 (left) and well 8 (right). The vertical axis is the direction of the azimuth stack where 0 degrees is East and 90 degrees it North. The horizontal axis is wavelength/2, which is interpreted as fracture spacing

Figure 6 shows the median spectral ratio, averaging over azimuths, for wells 4 (left) and 8 (right). A linear trend in the spectral ratio amplitude, attributable to attenuation (decreasing amplitude with increasing frequency), was removed. This curve amounts to a projection of the contours in Fig 5 along the x-axis.

Troughs are evident in both plots, consistent with discrete fractures spacing of about 30 to 40 m. A second, weaker trough around 60 to 80 m is discernable, corresponding to a twice fracture spacing, along with the peak around 50 to 60 m.

Figure 6. Averaged spectral ratios in the area around well 4 (left) and well 8 (right). The wavelength axis has been scaled by 2 so that fracture spacing may be read directly from the x-axis.

Some of these results can be validated with prior studies on this data. Figure 7 shows the borehole derived measurements for horizontal stress directions from Vetri et al. (2003). We've added the red arrow in the left rose diagram to highlight the direction of maximum horizontal stress, since the breakouts appear in the minimum horizontal stress direction. Generally fractures tend to align subparallel to the maximum horizontal stress direction.

Estimates of the aggregated fracture orientations using these volumes from the analysis of scattering indices are shown as rose plots in Figure 8, modified from Willis et al. (2004). The rose plots, which estimate the distribution of fractures in the area around well 4 (left) and well 8 (right), agree with the ENE and NNW directions derived in the studies mentioned above and shown in Figure 7.

Figure 7. Borehole Measurements: Stress measurements from borehole break outs in well 4 (left) and from natural fractures observed in the borehole in well 8 (right) (modified from Vetri et al, 2003). Vertical fractures tend to be aligned with the maximum horizontal stress direction.

Figure 8. Scattering Index: Rose diagrams showing fracture orientations in the area surrounding well 4 (left) and well 8 (right) from an analysis of scattering indices (Willis et al, 2004).

Figure 9. Spectral Notch Method: Rose diagrams showing fracture orientations using the method described in this paper, for the area surrounding well 4 (left) and well 8 (right).

For comparison, we derive a polar plot of the spectral ratio amplitudes for the bins corresponding to well 4 and 8 in Figure 9. Spectral ratio amplitudes are plotted versus angle, with the peak amplitudes identifying fracture directions. There is a reasonable consistency between the present results and prior work (Figs 7 and 8) in overall fracture directions. It should be noted that the three measures are at different scales: stress direction measurements in Fig 7 are essentially “point” measurements localized around a borehole, whereas the scattering index measures (Fig 8) are for an area covering about 0.5km x 1km while the spectral notch method measures (Figure 9) are for an area of 0.125 km x .25 km.

4. Discussion and Conclusions

We have presented a spectral notch method for extracting fracture characteristics from surface seismic data. The data volume is subdivided into 18 azimuth stack volumes. Spectral ratios are computed using windows of seismic data above and below the target reservoir for all azimuth stacks. The azimuth variation of the spectral ratio values can be used to detect both the spacing and orientation of fractures in the reservoir. For azimuths about 40 degrees or closer to the direction normal to fracturing, we expect to see spectral ratio notches (or zeros) indicating the absorption of seismic energy. The notches are

located at wavelengths which are about two times the fracture spacing. We expect that there is overall more energy, and thus more amplitude, in the spectral ratio for azimuths parallel to the fracture strike. These trends are clearly evident on the finite difference derived model data.

We applied the spectral notch method to the PP data derived from the 3D/4C Emilio field data. We observed significant variation with azimuth of the spectral ratios over the entire survey. We frequently observed notches corresponding to fracture spacings of 30 to 40 meters over the survey. Fracture orientations were also extracted using this approach and they agreed with prior studies, including borehole breakout and natural fracture analyses. They also agreed with estimates of seismically derived fracture orientations from scattering indices. These three results are consistent with each other even though they were derived from measurements averaged at three different scales – point (well based), 0.04 km² (spectral ratio notches), and 2.5 km² (scattering index).

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APPENDIX D

F-K Analysis of Backscattered Signal to Estimate Fracture Orientation and Spacing

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Abstract

We derive a methodology to determine orientation and average spacing of discrete fractures based on the analysis of seismic coda in the frequency-wavenumber domain. Discrete fractures are here understood as fractures with length and spacing similar to the seismic wavelengths leading to wave scattering. The seismic response of vertical, regularly spaced fractures, for different spacings, is studied through 3D finite difference models that incorporate discrete fractures using the equivalent medium theory of Coates and Schoenberg. The modelled data are then collected according to source-receiver azimuth and f-k transformed. Two observations are made of the Fourier characteristics of azimuthal gathers at the fractured level: 1. the energy in the negative wavenumber quadrant maximises for source-receiver azimuth normal to fracture strike and minimises in the fracture strike, and, 2. the distribution of energy in this quadrant varies according to fracture spacing, such that, backscattered signal from shorter fracture spacings contain higher frequencies-wavenumbers. Fracture related signal can be isolated with pass/reject f-k filters for further processing, specific to extract fracture parameters. Analysis of synthetic data indicates that fracture spacing can be recovered by computing half of the dominant wavelength of the backscattered signal. The technique is applied to field data from a fractured reservoir in the Adriatic Sea (Emilio field). The estimated preferential fracture orientation is about N160°E, which agrees with well data and seismic anisotropy studies. The estimated fracture spacing is approximately 50 m.

1 Introduction

In the characterization of fractured reservoirs, nowadays mature techniques include the processing of converted waves, AVOA analyses of P wave, NMO ellipticity, and others (Pérez et al., 1999). In all these techniques, the effect of fractures in the wave propagation is described by an equivalent azimuthally anisotropic medium.

Another approach consists of accounting for the fractures as discrete inclusions in the medium. There are several ways of modelling discrete fractures. In particular, Schoenberg’s theory (Schoenberg and Sayers, 1995) is an effective medium theory in which the effective compliance of a fractured rock is expressed as the sum of the unfractured rock compliance, plus an excess compliance per each set of aligned fractures.

When the fractures are planar and parallel, the components of the fracture system compliance tensor are related to jump discontinuities in the displacements. This is the linear slip deformation model. If the set of fractures is rotationally invariant, the compliance is only a function of its shear and normal components, which can be determined experimentally (Hsu and Schoenberg, 1993), or related to microstructural models (Liu et al., 2000). In the presence of just one set of fractures, and if the set is so called “scalar” (because normal and tangential compliances are equal), an isotropic background medium becomes TI with its symmetry axis perpendicular to the fractures.

Discrete approaches are valid in the limit where the seismic wavelength is comparable to the fractures, either in size, aperture, spacing or length. The typical resolution of seismic waves at depths of common reservoirs is 30-70 Hz which corresponds to wavelengths on the order of 25 to 200 m for typical rock velocities. The seismic response of discrete fractures is characterised by scattered energy in the coda of seismic waves usually considered noise in signal processing. However, recent studies (Willis et al., 2004; Vlastos et al., 2003), show that the apparent noise is indeed a complicated effect of the presence of fractures in the wavepath and, as such, it contains valuable information of the geometry and properties of the fractures themselves.

In this paper, we investigate the scattering energy from discrete fractures in the frequency-wavenumber domain aiming to estimate their orientation and mean spacing. In the first part we present the analysis on synthetic data and derive a methodology; in the second part, we show its application to a real dataset.

2 Model

Modelled data were generated using the 3D elastic-anisotropic finite difference code developed by the Lawrence Berkeley National Laboratory (Nihei et al., 2002). The implementation is based on a velocity-

stress formulation defined in a standard staggered grid with an explicit operator, 4th order in space and 2nd order in time. Fractures are simulated following Coates and Schoenberg method (Coates and Schoenberg, 1995), in which an effective anisotropic stiffness tensor is assigned to one or several cells in the finite-difference grid to represent fractures amid a background medium.

The model, figure 1, consists of 5 horizontal, isotropic, layers with typical sedimentary rock velocities and densities (table 1). The third layer simulates a reservoir with vertical aligned fractures, regular spaced, that extend along the model dimensions and across the reservoir thickness (200 m). Effective properties for the discrete fracture zones are assigned to a single grid cell, of 5 m, where normal and tangential stiffness values are chosen as $8 \times 10^8 Pa/m$ to represent effectively compliant gas-filled fractures. The medium in these cells is TI with a horizontal symmetry axis (HTI). Fracture spacings modelled are 0 m (no fractures), 10 m, 25 m, 35 m, 50 m, 100 m, and, a Gaussian distribution with mean spacing 35 m and standard deviation 10 m. The model of fractures spaced 10 m was found to be below the scattering limit.

For all models, a shot record is obtained locating a point source in one corner, and three-component and pressure receivers every 5 m, on the surface. The source is modelled as a 40 Hz Ricker wavelet, hence wavelengths in the reservoir layer are around 100 m for the P wave and 59 m for the S wave.

The data are sorted by source-receiver azimuth every 10 degrees, and a mute function is applied to remove the direct arrival. The vertical component for the 35 m case, at several azimuths, is shown in figure 2. For comparison, the record at the top corresponds to a model without fractures. 0° azimuth is the direction normal to fracture strike as indicated in figure 1.

The P reflections generated at zero offset from the top of the 2nd layer, the top and base of the reservoir, and the top of the 5th layer, arrive at about 170, 290, 395 and 500 ms, respectively. There is a strong arrival at about 220 ms which corresponds to the converted S wave from the top of the 2nd layer. All these arrivals are identifiable irrespective of the acquisition orientation, however, the fractures introduce significant energy that relatively affects the coherence of the last two reflectors. It is the character of this energy what varies with azimuth, exhibiting reverse moveout at 0 degrees and rotating with azimuth until it displays similar moveout to the primaries in the direction of the fractures. At 0 degrees, energy is greatly scattered by the fractures, whereas at 90 degrees fracture planes behave as reflecting out-of-plane surfaces. Energy seems to get trapped between fractures, delaying its arrival to the surface receivers, as in the case of conventional multiples.

3 Backscattered Signal

In the previous section we described the differences in the seismic response of the modelled data as the azimuth of propagation varies. It was established in figure 2 that as the observation point becomes oriented normal to fracture strike, the coda contains more energy associated to scattering generated from the fractures. Most of this energy appears as if backscattered.

Back or side scattered energy is conventionally treated in seismic processing as unwanted coherent noise. In field records, it is common to observe backscattered components of guided waves when the ocean bottom presents irregularities.¹ In this case, the irregularities act as point scatterers. Other sources of side scattering may be, for example, sea-bottom pipelines (Yilmaz, 2001). Filters in the frequency-wavenumber domain have proven successfully in attenuating the effects of scatterers, basically because the moveout differences with primary reflections exacerbate in the f-k space, thus increasing the performance of dip filtering.

The scattering characteristics of parallel fractures are somewhat different to the examples above because fractures are not entirely random features, instead they occur as part of regular sets with a certain preferred orientation, similar length, constant spacing, etc. The wavelengths scattered by discrete fractures are similar not only to the individual fracture geometry but also to that of the fracture system.

Figure 3 shows the f-k spectrum of several gathers. The one on the far right corresponds to the 0 m (no fractures) case shown in the previous figure. We can easily identify how the main events in the time-offset space map into the frequency-wavenumber domain:

1. Reflections (hyperbolas) at near offsets, are almost flat or of apparent infinite velocity. Such signals map onto the zero wavenumber axis. As the offset increases, reflectors become curved towards positive time, and so does the energy in the positive wavenumber plane.
2. Residuals of the direct arrivals, mute effects, conversions, and tails of hyperbolas at large offsets, all of which have a linear positive character in the time-offset space, transform in the positive wavenumber plane also as linear events. Since the velocities of these events are relatively slow, spatial aliasing could occur and wrap around, appearing at lower frequencies in the negative wavenumber plane (not the case for the modelled data). To avoid wrap-around noise associated to the Fourier transform, data are at least duplicated, padding with zeros.

The first two f-k plots at the center of figure 3 correspond to the 50 m fracture spacing case, at 90° and 0°, respectively. The corresponding time data are shown on the left. By comparison with the no

¹In land data, ground roll might exhibit a backscattered component as well

fractures case, we identify the changes in the f-k domain introduced by the presence of fractures, as well as the sensitivity to orientation:

3. Parallel to fracture strike, the time domain response includes numerous “multiple” reflections below the P-P reflector associated to the top of the reservoir. Since these events have similar moveout (positive) to the primaries, they map in their vicinity.
4. The backscattered energy, observed at 0 degrees, shows reverse linear moveout in the time-offset space. In the f-k domain, this energy maps in the negative wavenumber plane. The appearance of energy in the negative wavenumber quadrant is the most important effect of the fractures. As a secondary effect, deeper reflections, below the reservoir, and their respective conversions, become less coherent in the t-x space, therefore, the energy in the positive wavenumber smears over a broader range of values. A third effect is related to the forward scattered signal from the fractures; this energy maps into the positive wavenumber quadrant with the slowest velocity.

The last two plots in figure 3 show f-k spectra for cases in which the fracture spacing is half (25 m) and double (100 m) that of the previous case, both corresponding to the 0 degrees azimuthal gather. The intention is to exemplify the sensitivity of the f-k transform to different fracture spacings:

5. Normal to fracture strike the distribution of energy in the f-k space changes according to fracture spacing. As the spacing increases, a bigger percentage of the total energy maps into the negative wavenumber quadrant. In this plane as well, the number of notches increases with fracture spacing.
6. As fracture spacing increases, the backscattered signal contains lower frequency-wavenumber components. As a result, larger amplitudes in the negative wavenumber plane focus at lower f-k values.

4 Determining Fracture Orientation

Figure 4 shows the f-k spectrum of some azimuthal gathers from the model in which fractures are spaced 35 m. Unlike the spectra in figure 3, the 2D Fourier transforms are computed here in a window in time and offset, including the reservoir, as indicated in figure 2. Data windowing is necessary to avoid confusing the signal from the fractures with scatterers that might be present in the overlying formations (not the case for these models). Additionally, conversions observed at large offsets, any residuals of direct arrivals, and mute effects, have been left out.

We compute the energy associated to the backscattered signal by summing the square of the amplitudes in the negative wavenumber quadrant:

$$E_{scatt} = \sum_{-k_N}^{0_{(-)}} A^2 \quad (1)$$

where k_N refers to the Nyquist wavenumber.

The behaviour of this energy with azimuth exhibits a maximum when the orientation is perpendicular to fracture strike and a minimum when parallel (figure 5), for all model cases. Therefore, the preferred orientation of fractures can be derived by comparing the backscattered energy at different azimuths.

5 F-K Filtering and Fracture Spacing Determination

The backscattered signal can be isolated from the rest by designing filters in the f-k domain. Once the data, exclusively associated to the fractures, are extracted, estimation of fracture properties should be largely simplified.

We aim to determine mean spacing between fractures. In order to do so, the data gathered at 0 degrees are filtered. An f-k filter is implemented such that signal falling into the negative wavenumber quadrant is passed, while positive wavenumber signals are rejected. In more detail, amplitudes in the positive wavenumber quadrant are zeroed out and the resultant f-k spectrum is inverse transformed. The filter is applied to the windowed data. For the 35 m fracture spacing model, figure 6 shows that the filter has effectively removed the forward propagating energy boosting the signal directly related to the fractures. In practical applications, a data cube of backscattered signal could be generated.

The next step consists of estimating the dominant velocity, V , of the backscattered events. In the filtered data, the velocity observed is about 5620 m/s (fig. 6), which corresponds to an apparent velocity. By inspection of the f-k spectrum at 0° , the dominant frequency, f , is about 80 Hz, hence the mean spacing can be obtained as:

$$D = \left(\frac{1}{2}\right) \frac{V}{f} = 35.125m. \quad (2)$$

Note that the spacing can also be estimated from the 2D Fourier transform of the filtered data by taking half of the inverse of the dominant wavenumber: $(1/2)(1/0.0141m^{-1}) = 35.461m$.

Results corresponding to other fracture spacings are summarised in figure 7 where the maximum amplitude in the spectrum of each case is indicated. In the time window analysed, the apparent velocity is faster for larger fracture spacings whereas frequency and wavenumber decrease.

6 Field Data

The previous methodology is applied to surface seismic data from the Emilio field in the Adriatic Sea. The reservoir is a fractured carbonate of Paleocene age located at a depth of 2850 m (about 2.2 s) (Gaiser et al., 2002). Gas is currently produced from its upper level, the Scaglia formation. Overlying the target limestones, lithologies vary from clastics to the evaporites of the Gessoso Solifera formation, which is associated to a particularly strong seismic reflector at 1.9 - 2 s.

The structural setting of the area is dominated by an east-west compressional regime. Breakouts and induced fractures analysed at some boreholes indicate that the maximum horizontal stress runs ENE, however, a perpendicular orientation has been observed in other wells. Evidence of a dual set of fractures with orthogonal orientations, ENE and NNW, was interpreted from PP and PS azimuthal anisotropy analyses (Vetri et al., 2003).

The Emilio 3D/4C OBC survey was acquired in early 2000 with the main objective of identifying the fracture system in the carbonate reservoir. Shot lines were oriented N80°E while receiver lines were oriented perpendicularly. The orthogonal pattern produced an uniform azimuth distribution and high fold coverage at mid and far offsets.

6.1 Feasibility and Azimuthal Gathers

In general, the definition of a time window to perform the f-k analysis becomes more critical in real data. If the reservoir is not properly isolated from the overburden, fracture-related signal may be contaminated with the effects of near surface scatterers or overlying fractured layers of no interest. As a quick evaluation, figure 8 shows an example shot record of Emilio. Fourier transforms are computed in two windows as indicated by the red and blue markers. The late time window includes the reservoir. We observe that there is significant backscattered signal (negative quadrant) from the fractured reservoir. The total energy on the early time window is weaker and mostly concentrated in the positive wavenumber quadrant. Therefore, although in the Emilio field data identification of the top of the reservoir is difficult due to its low impedance contrast, an approximate window around the reservoir level could still provide useful results.

Data corresponding to 20 shot records in a particular swath, were chosen to apply the methodology (figure 9). We adopt the following convention: in map view, 0° (and 360°) corresponds to the East direction; angle increases counterclockwise, such that, North is located at 270° (see inlet in figure 9). As described before, the first step consists of the azimuthal sort of the field records. From the acquisition geometry, it is

clear that around 190° , the azimuth of the shot lines, the recorded offsets are limited to a near range which is less than 1100 m, therefore, only these offsets are considered for all azimuths. Data are collected every 20 degrees, approximately, and some gathers are shown in figure 10. For display, an AGC of 100 ms was applied. Especially in the time window indicated, coherence of reflections changes with angle and they are most coherent at 110° and again at 290° .

It is advantageous that the procedure is applicable in the field geometry domain; practically no other pre-processing is necessary. On the other hand, and unlike CMP gathers, interpreting data in the shot domain has a complicated physical meaning because subsurface image locations vary from trace to trace. Nonetheless, we can assume that the fracture characteristics sought are relatively invariable spatially.

6.2 Fracture Orientation

F-k transforms are computed for the azimuthal gathers in the offset-time window indicated in figure 10. The corresponding spectra are shown in figure 11 where each f-k plot is normalized independently.

Following the procedure for determining fracture orientation in section 4, we sum the energy in the negative wavenumber quadrant and compare it to the total energy. Figure 12 depicts the variation of the backscattered energy normalised to the total energy at each angle. A clear maximum is reached around 190° whereas the minimum energy is recorded 90° away. The difference between maximum and minimum energy varies according to the frequency-negative wavenumber range of values input in the sum. In the figure, we show results for 3 ranges: 1. all frequencies and all negative wavenumbers, 2. frequencies between 12 and 32 Hz and all negative wavenumbers, and, 3. a variable range for every azimuth according to an interpretation of what is meaningful signal and what is noise. Even for the first case, in which no interpretation is attempted, a clear difference is observed, showing that the determination of fracture orientation is robust.

For the Emilio field data analysed, the preferential fracture strike coincides approximately with the receiver lines orientation, that is, in the NNW direction. The backscattered signal is maximised in the direction normal to the fractures (ENE).

6.3 Fracture Spacing

Once the direction normal to fracture strike is identified, we proceed to determine the average fracture spacing. To start, backscattered signal related to reservoir fractures is isolated by filtering the 190° azimuthal gather. As with the modelled data, the filter is implemented in the f-k domain and energy falling into the positive wavenumber plane is rejected. In addition, frequencies are bandpassed between 10 and 40 Hz.

Figure 13 shows the original and filtered data. At the bottom plot in the same figure, most coherent velocities calculated with a running window in time and across all traces, are indicated with warm colours. The dominant velocity is observed consistently around 2400 m/s. The f-k spectrum of the backscattered data, showed in figure 11, exhibits an energy maximum at 24.6 Hz and -0.0094 1/m.

By taking half of the inverse of the dominant wavenumber or, alternatively, half of the ratio of dominant velocity to dominant frequency, a fracture spacing of about 48 to 53 m is obtained.

7 Conclusions

Based on modelled data we derived a simple yet robust method to estimate fracture orientation and spacing. The method develops from the evidence that backscattered seismic waves are generated from fracture systems. Backscattered signals can be isolated using f-k filters to simplify fracture characterization.

In the f-k domain, backscattered energy decreases as the observation angle becomes oriented with fracture strike. Fracture spacing corresponds to half the dominant wavelength. We applied the method to real data from the Emilio field and observed that fractures are oriented NNW at the particular location analysed. Fracture spacing was estimated around 50 m.

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Figure 1: On the left, model geometry. On the right, a map view of the top of the fractured layer and the convention used for the azimuthal sort.

Table 1: Model velocities and densities

Layer	Vp [m/s]	Vs [m/s]	Density [g/cc]
1	3000	1765	2.2
2	3500	2060	2.25
3	4000	2353	2.3
4	3500	2060	2.25
5	4000	2353	2.3

Figure 2: Modelled data. At the top, shot gather for the case of no fractures. In the middle and last rows, data from the 35 m-fracture spacing model after sort by azimuth. The time-offset window is indicated on top of the 90° gather.

Figure 3: F-k spectra. Corresponding data are shown on the left. On the right, f-k spectrum of the no fracture case (data showed in figure 2).

Figure 4: F-k spectra of data from the model 35 m-fracture spacing, computed at a window in time and offset (indicated in figure 2), and for different azimuths.

Figure 5: Backscattered energy as a function of azimuth for all cases modelled.

Figure 6: Top row, from left to right, original data of model 35 m at 0° in time-offset window, backscattered signal passed with a f-k filter, and forward scattered signal rejected with filtering. At the bottom, the f-k spectrum of the filtered data showing dominant frequency, wavenumber and velocity.

Figure 7: Energy maximum in the f-k spectrum varies with fracture spacing. In all cases, fracture spacing is approximately half of the inverse of the dominant wavenumber: $(1/2)(1/0.0047m-1) = 106.4m$; $(1/2)(1/0.0094m-1) = 53.2m$; $(1/2)(1/0.0134m-1) = 37.3m$; $(1/2)(1/0.0191m-1) = 26.2m$.

Figure 8: Shot record # 11664 from the Emilio 3D survey (for location see next figure). On the right f-k spectra in two different windows: above (blue) and in the reservoir (red).

Figure 9: Location of shot records analysed in this study, and acquisition geometry. In the inset figure, convention assumed in the azimuthal sort of the data.

Figure 10: Shot records from Emilio survey after sorting by azimuth every 20° approximately. Labels represent average azimuth in the gather, for example, azimuths between 100° and 120° are collected in the gather labeled 110° . The time-offset window used in the calculations is indicated in red.

Figure 11: F-k spectra of data showed in figure 10. Dominant frequency and wavenumber are indicated for the 190° gather.

Figure 12: Percentage of backscattered energy at each azimuth. The 3 curves correspond to different ranges of frequencies and wavenumbers entering the calculation of energy: all negative wavenumber quadrant (red), all negative wavenumbers and frequencies between 12 and 32 Hz (blue), and, a variable range for each azimuth (green).

Figure 13: Top row, from left to right, original data from azimuthal gather around 190° in time-offset window, backscattered signal after f-k filter and bandpass, and forward scattered data rejected with filtering. At the bottom, semblance-type plot of most coherent velocity across all traces in the filtered data.

APPENDIX E

Spatial Orientation And Distribution Of Reservoir Fractures From Scattered Seismic Energy

Shortened title: Fracture characterization from coda energy

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ABSTRACT

We present the details of a new method for determining the reflection and scattering characteristics of seismic energy from subsurface fractured formations. The method is based upon observations we have made from 3D finite difference modeling of the reflected and scattered seismic energy over discrete systems of vertical fractures. Regularly spaced, discrete vertical fractures impart a ringing coda type signature to any seismic energy which is transmitted through or reflected off of them. This signature varies in amplitude and coherence as a function of several parameters including: 1) the difference in angle between the orientation of the fractures and the acquisition direction, 2) the fracture spacing, 3) the wavelength of the illuminating seismic energy, and 4) the compliance, or stiffness, of the fractures. This coda energy is the most coherent when the acquisition direction is parallel to the strike of the fractures. It has the largest amplitude when the seismic wavelengths are tuned to the fracture spacing, and when the fractures have low stiffness. Our method uses surface seismic reflection traces to derive a transfer function which quantifies the change in an apparent source wavelet before and after propagating through a fractured interval. The transfer function for an interval with no or low amounts of scattering will be more spike-like and temporally compact. The transfer function for an interval with high scattering will ring and be less temporally compact. When a 3D survey is acquired with a full range of azimuths, the variation in the derived transfer functions allows us to identify subsurface areas with high fracturing and determine the strike of those fractures. We calibrated the method with model data and then applied it to the Emilio field with a fractured reservoir giving results which agree with known field measurements and previously published fracture orientations derived from PS anisotropy.

Keywords: fracture, scattering, coda, scattering index

INTRODUCTION

Evidence continues to confirm that much of the earth's crust, especially below a critical depth of 500 to 1000m, contains a predominance of nearly vertical fractured rocks (Crampin and Chastin, 2000) typically aligned subparallel to the regional direction of maximum compression or about 45 degrees to the axis of principal stress (Crampin *et al*, 1980). These natural fracture systems in an oil and gas reservoir frequently dominate the fluid drainage pattern, turning hydrocarbon saturated rocks with even low matrix permeability into significant commercial assets. In many low permeability oil fields, hydraulic fracturing is undertaken to enhance the natural system of fractures and increase production rates (e.g. Block *et al*, 1994; Fehler *et al*, 1998; Phillips *et al*, 1998; House *et al*, 2004). An understanding of these fracture systems is crucial for field development planning in order to more completely drain the reservoir from the fewest number of wells.

Seismic waves traveling through a rock formation containing aligned fractures are affected by the fractures' mechanical parameters, such as compliance and saturating fluid, and on their geometric

properties. If the fracture dimensions and spacing are small relative to the seismic wavelength, then the fractures cause the reservoir rock to behave like an equivalent anisotropic medium with a symmetry axis normal to the strike of the 'open' fractures. Resulting seismic reflections from the top and bottom of a fractured reservoir will display amplitude variations with offset and azimuth (AVOA). In recent years much progress has been made analyzing AVOA effects (e.g., Lynn et al., 1996; Sayers and Rickett, 1997; Perez et al, 1999; Shen and Toksöz; 2000; Jenner, 2002; Shen et al, 2002; Hall and Kendall, 2003; Lynn and Cox, 2003; Minsley et al, 2004).

If, however, the fracture dimensions and spacing are close in size to the seismic wavelength, then the fractures will scatter the P- and converted S-wave energy causing a complex, reverberating, seismic signature or coda. This seismic signature will vary as a function of the orientation of the seismic acquisition relative to the fracture orientation. Work by several authors (e.g. Ata and Michelena, 1995; Schultz and Toksöz, 1996; Daley et al, 2002; Nakagawa et al, 2002; Wu et al, 2002; Nakagawa et al, 2003; Willis et al, 2004a) using ultrasonic scale modeling and numeric simulation have demonstrated complicated, azimuthally varying scattering patterns by simulating systems of subsurface, aligned fractures. The scattered seismic energy not only provides information about the fracture orientation, but can also be analyzed to provide information about the fracture spacing (Willis et al, 2004a) and fracture density (Pearce, 2003).

In this paper we describe our recent work (Willis et al, 2003; Willis et al, 2004a; Willis et al, 2004b; Willis et al, 2004c; and Burns et al, 2004) to extract fracture distribution and orientation from scattered coda waves where the fracture systems are of a size comparable to the wavelength of the seismic source. We first describe our modeling results of vertically fractured reservoirs, our methods to extract the fracture properties from surface reflection seismic acquisition data, and finally the results on field data.

MODELING

We model a simple reservoir using the 3-D anisotropic, elastic, finite-difference code developed by Lawrence Berkeley National Laboratory (Nihei et al., 2002). The code implements the algorithm described by Levander (1988) which uses a staggered grid with an explicit, fourth order operator in space and a second order operator in time. The model geometry (Figure 1) and parameters (Table 1) we used consists of five horizontal layers. All the layers except the middle, third layer, are homogeneous and isotropic elastic media. The background medium for the third layer is isotropic and homogeneous. We want to simulate a periodic series of parallel, vertical fractures inserted into this layer. So we use the Coates and Shoenberg (1995) method to represent the fractures by grid cells containing equivalent anisotropic medium. Vlastos et al (2003) have recently use this same approach in a 2-D pseudospectral approach for modeling scattering from fractures.

Following Daley et al (2002), we use normal and tangential fracture stiffness values of 8×10^8 Pa/m representing long, compliant, gas-filled fractures. The grid cells containing the fractures are chosen to be vertical planes, a single grid cell thick (5m), as tall as the layer thickness (200m) which run the entire width of the model (i.e. parallel to $x = 0$). We generated a series of models with the following regular fracture spacings: no fractures, 10m, 25m, 35m, 50m, and 100m. We also generated another model to insure that our results would not be restricted to perfectly regular fracture spacings. The model has a Gaussian distribution of vertical, parallel fractures with a mean spacing of 35m and a standard deviation of 10 m.

On the left side of Figure 2 are the shot records for the 50 m fracture spacing case acquired in directions normal (top) and parallel (bottom) to the fractures. The P wave reflections off the top of layers two and three arrive at zero offset times of about 170 and 290 ms, respectively. The arrival at 220 ms is the converted S wave reflected off the top of layer two. Below these three distinct arrivals, are a series of events corresponding to the scattering from the fractures.

To the right of each shot record in Figure 2, is its semblance-based, stacking-velocity analysis. Since the model interval P velocities are all above 2900 m/s, it is clear that the shot record normal to the fracture direction (top) has very little coherent and stackable P energy below the top of the reservoir level (290 ms). However, for the parallel case (bottom), there are many coherent events below the top reservoir reflection. In the direction parallel to the fractures, the seismic energy seems to be guided by the aligned fractures and the resulting scattered energy is more coherent and similar to the direct P wave reflection. This same pattern of azimuthal variation in the modeled scattered wavefields is observed for all the model results regardless of the fracture spacing. For the dual fracture model, this same pattern is seen for the primary fracture set but the effect of the secondary fracture set is not very large.

For shot records acquired parallel to the fractures, the ringing scattered events are seen to be the most coherent on the near through mid offset ranges. Figure 3a shows ten azimuth stacks. They were created by applying normal move out and stack to different azimuth ranges of the model traces starting in the direction normal to the fractures, then rotating by 10 degree increments, until finally parallel to the fractures. The trace labeled “normal” corresponds to the stack of the traces in the top left plot of Fig. 2. The trace labeled “parallel” corresponds to the stack of traces in the bottom left plot of Fig 2. These stacks do not include the far offset traces. For comparison, the bottom trace labeled “control” is the stacked trace from the model without fractures. For shot records acquired normal to the fracture direction, the observed scattered wave field is greatly disruptive with significant back scattered, diffraction-like events. These traces do not stack together well with any NMO velocity. However, the traces acquired parallel to the fractures stack in considerably better. Based upon these observations, the strike of the fracturing may be determined by identifying the acquisition direction with shot records containing coherent, ringing energy which are enhanced the most when stacked. Figure 4a shows the azimuth stacks for the other models studied. This same trend is present for all models except the 10m fracture spacing case. For this model the fracture spacing is so small that the third layer behaves more like an equivalent anisotropic medium than one with large scale fracturing.

EXTRACTING SOURCE WAVELET AND COMPUTING TRANSFER FUNCTION

In the synthetic traces we generated, it is possible to directly observe the scattered waves and their azimuthally varying trends. This is due to the fact that there are only a few, isolated reflectors in the model. However, in field data we expect to have a more difficult time clearly observing these scattered wave trains due to the nearly continuously changing nature of subsurface reflectivity and the potentially lower amplitudes of the scattered energy. Figure 5 is a schematic showing that reflections off beds shallower than a fractured zone will not be affected by it. However, reflections from below it will acquire a ringing coda caused by reverberations in the fractured zone. In addition, if the overburden is fractured, those scattered waves will contaminate, or overprint, the scattered energy from the zone of interest in the reservoir. Thus the problem we face is detecting the change in the reflection character of an apparent source wavelet as we move down each trace. Specifically, we want to detect the change in the temporal “compactness” of the apparent source wavelet as it passes through each formation of interest.

Traditional methods of source wavelet extraction are based upon the notion of the stationarity of the seismic wavelet, which means that the source wavelet doesn’t change with time down the trace (Yilmaz, 1987). For our purposes, we assume stationarity only within each time window used to estimate the source wavelet. However, due to the mode conversions and reverberation in the fractured interval, the apparent source wavelet does change with time down the trace. So we extract two apparent source wavelets from the reflection time series – one from above the proposed fractured zone (the “input” wavelet) and one below it (the “output” wavelet). These wavelets are represented by their autocorrelations obtained from windowed portions of the reflection time series above and below the fractured zone of interest. We make the standard assumption that the reflectivity series is white. Hence, the autocorrelation of the windowed time series yields the autocorrelation of the source wavelet in that window.

We then compute the time domain transfer function (sometimes called the impulse response) between the autocorrelations of the two extracted wavelets. The transfer function is computed by deconvolving the autocorrelation of the input wavelet from the autocorrelation of the output wavelet using the Weiner-Levinson algorithm (Robinson and Treitel, 1980). Alternatively, another deconvolution method like spectral division could be used. The transfer function characterizes the effect of scattering in the interval of interest between the two windowed portions of the trace. Since both the input and output autocorrelations are zero phase, the resulting transfer function will also be zero phase and symmetric. A simple spike or pulse shaped transfer function indicates no scattering, while a long ringing transfer function reveals that scattering has occurred within the proposed interval between the analysis windows. This measurement will be insensitive to contamination from an acquisition footprint or from scattering in the overburden. This is due to the fact that these effects would appear on both the input and output extracted wavelets and thus will be excluded from the transfer function.

The transfer function can be used to characterize scattering on both pre- and post-stack data. On pre-stack data it can detect the presence of scattering on a single trace. However, it can also be used to determine the orientation of fracturing by comparing the change in the transfer functions from stacked traces with different acquisition orientations. The transfer functions from traces stacked in the direction parallel to fracturing will exhibit more ringing than those in the direction normal to fractures. To show this on the 50m fracture spacing model data, we choose the input and output time windows on each of the traces in Figure 3b, as delineated by the labeled bars beneath the traces. We form the autocorrelation of each window and then compute the transfer function between each corresponding pair of autocorrelations. Figure 3b shows the derived transfer functions. Notice that the transfer function for the control case, the model without fractures, is very impulsive and is similar to a band limited spike. The transfer function for the stacked normal trace strongly resembles the control case. The transfer functions show very little change in shape until they are within 10 degrees of the fracture strike direction, indicating a sharp angular resolution. The transfer function for the parallel trace rings for about 100ms in each direction and is very different from the other functions.

We have applied this analysis to all of the other models and the results are shown in Figure 4b. In all cases except the 10m fracture case, the transfer functions ring most prominently in the direction parallel to the fracturing. (As discussed earlier, the 10m fracture case behaves more like an equivalent anisotropic medium than one that shows discrete fracturing.) From these examples it is clear that the marked ringing behavior of the transfer function for the stacks in the direction parallel to the fractures is a characteristic phenomenon and not an artifact of a random perfect resonance in a particular model. Therefore the transfer functions can be used to estimate fracture orientation.

METHODOLOGY FOR SCATTERING INDEX

We have shown that stacks made from traces acquired parallel to a prominent fracture system retain the ringing scattered coda energy on the traces. Stacks made in other acquisition directions tend to diminish the scattered coda energy. This same trend is evident on the corresponding transfer functions. By design, a transfer function is symmetric about zero lag so we only need to examine its positive time lags. Looking more closely at the transfer functions for orientations parallel to fractures, we clearly see the ringing coda creates energy in the transfer function at times away from the zero lag. However, in the normal direction the transfer functions are comparatively compact about the zero lag.

In order to quantify the amount of ringing or non-compactness in a transfer function, we define a scattering index, SI, with a form given by:

$$SI = \sum_{i=0}^m |t_i| i^n$$

where i is the time lag, t_i is the transfer function (time domain) amplitude at lag i , n is an exponent, typically equal to unity, and m is a lag at which there is no more significant energy in the transfer function. (It is also possible to normalize the scattering index based upon its energy and interval time sample or other such criteria.) This expression weights the large lag times more heavily than the near zero lag times in the transfer function. The more the transfer function rings, the larger the value of the scattering index. If the transfer function is a simple spike, i.e. representing no scattering, then the scattering index attains a value of zero.

Figure 6 shows the scattering index values for the models with 25, 35, 50 and 100m fracture spacings. The extent of the model doesn't afford a complete 360 degree acquisition direction analysis so we've replicated appropriately the first quadrant analysis for the other three quadrants. These results show that there is a clear maximum of the scattering index in the parallel direction. It is also clear that in the non-parallel directions the scattering index is not zero but fluctuates about a smaller, but somewhat consistent value. The scattering index formulation allows us to extract the amount of ringing in the transfer functions as a single digit making it easier to analyze, display and therefore detect the strike of the fracturing.

RESULTS ON FIELD DATA

In early 2000, a 3D/4C seismic survey was collected over the Emilio Field, located in the central part of the Adriatic Sea, near the eastern coast of Italy. The reservoir unit is a fractured carbonate which from borehole studies suggests the presence of two orthogonal fracture sets oriented ENE and NNW (Angerer et al, 2002). Recent studies have investigated this 3D seismic data using PP and PS wave anisotropy to identify fracture characteristics of the reservoir level (Vetri et al, 2003; Gaiser et al, 2002). Figure 7 (taken from Figure 10 of Vetri et al, 2003) shows the interval velocity log, the interpreted seismic section and structural model of a profile through the field. The most prominent reflector in the section is the Gessosso-Soliferera, highlighted in green, which is a high velocity chalk formation. The reservoir interval is shown between the cyan and purple lines on the seismic section.

We stacked the near to mid range (< 3500 m) offsets of the preprocessed PP data (Vetri et al, 2003) in eighteen different azimuth orientations from East to West using 20 degree wide overlapping ranges, in 10 degree steps. (Note that these angle ranges included the corresponding ranges 180 degrees away.) This process created eighteen 3D stacked volumes. The transfer functions and scattering indices for the formation zone were computed for each of these stacked volumes. The scattering indices were sorted and directions for those with the highest angular contrast in values (differences > 5) are shown as quivers in Figure 8, giving a map view of the location and direction of possible fractures determined by this method.

The locations of the fracture measurements are taken from stacked data, and as such, their locations are in the un-migrated positions. To adjust for this potential mis-positioning, we performed a map migration of all the scattering indices with angular contrasts greater than 4. These results are shown as blue quivers in Figure 9. Here we have used the coordinate system of inlines and cross lines (rather than Northings and Eastings in Figure 8) to be able to plot the seismically derived fault system (in black) and well information on the same diagram. We observe that the clusters of the blue quivers tend to congregate around the fault zones. In addition, we see the quivers tend to align either parallel or perpendicular to the faulting.

The left side of Figure 10 shows a rotated version of Figure 9, to align with the Northings and Eastings coordinate system. The right side of Figure 10 is a plot of the scattering directions for all the CDP locations in the survey, without omitting low angular contrast values. The scattering index directions have been color coded using the color legend on the top right of the figure. Small angular contrasts in the scattering indices are denoted by tinting the color of the corresponding CPP cells toward the center of the color legend wheel which is white. Larger angular contrasts are tinted toward brighter colors at the edge of the legend color wheel indicating greater confidence. Green, Red, Gray and Blue colors indicate fracture strikes of East, Northeast, North and Northwest, respectively.

We next compare our fracture directions with those derived by shear wave anisotropy. The left panel of Figure 11 (modified from Figure 10 of Vetri et al, 2003) shows the fracture strike direction derived from the fast direction of the PS waves. We have added three black arrows to help interpret their color scale. In the right panel of Figure 11 we have taken our fracture directions (from Figure 10) and performed modal smoothing of the directions using a 200x400m box centered about each CDP. As before, we plotted arrows indicating three fracture direction trends. The red, large area in the lower part of the right panel is the most obvious feature. This area indicates a fracture direction of NE which is identical to the direction indicated by the shear wave data. Close comparison of the figures shows that the directions agree over much of the survey.

The final result is shown in Figure 12 comparing well derived fracture orientations with those derived by the scattering index analysis. The top row shows the well information (from Vetri et al., 2003) indicating the direction of horizontal stress maximum (SHmax). In general, fractures align subparallel to the SHmax direction. We added a red arrow to the well 4 results to emphasize the SHmax direction, since break out directions tend to align in the SHmin direction. The middle row shows close-ups from Figure 9 around these three wells. To further clarify the fracture trends, we histogrammed the map migrated scattering directions around each well and plotted them in rose diagram format in the bottom row of Figure 9. It is clear that there is good agreement of the scattering index derived orientations with the well derived fracture orientations at these three wells.

CONCLUSIONS

Large-scale zones of fracturing control fluid flow in certain reservoirs, and such zones can scatter seismic energy depending on the fracture density and compliance, as well as the spacing relative to the seismic source wavelength. This scattered wave energy contains information about the fracture properties. Using numerical modeling data we developed a method of analyzing scattered wave energy from fractured reservoirs. A deconvolutional process that measures the ‘ringiness’ of the transfer function can be used to estimate fracture orientation from azimuthally stacked data. The application of this method on field data provide fracture orientation estimates which agree very closely with previous borehole studies and with the general trends of the PS anisotropy studies in the Emilio field. The anisotropy measurements contain information about the fine (with respect to the seismic wavelengths) scale fracturing in the formation. However, the fracture measurements obtained by this study measure discrete fracture properties which are on the order of the seismic wavelength. As such, we would expect the kinds of differences we observe between the anisotropic (fine scale) and scattering index (seismic wavelength scale) fracture direction estimates. The value of the scattering index methodology is that is a very simple, easy to parameterize algorithm that should not be prone to overburden effects. Its application on both model and field data show that it is both robust and accurate.

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Table 1. Parameters for model

Layer	Thickness (m)	V_p (m/s)	V_s (m/s)	Density (g/cc)
1	200	3000	1765	2.2
2	200	3500	2060	2.25
3	200	4000	2353	2.3
4	200	3500	2060	2.25
5	200	4000	2353	2.3

FIGURE CAPTIONS

Figure 1. Diagram showing the geometry of the 3D finite difference model. The dimensions of the model, not including the absorbing boundaries, are 1875m in x and y and 1350m in depth, z. The layer velocities and densities are shown in Table 1. The source is located in the left front corner (red symbol) and the receivers are spread out in a rectangular area 1000 m in the x direction and 1000m in the y direction. The receiver spacing is 5m in each direction.

Figure 2: Left two plots show the seismic shot records for the model with 50m fracture spacing. The top left plot show the shot record normal to fractures, left bottom plot shows the shot record parallel to the fractures. The right two plots show the velocity spectra for the corresponding shot records on the left.

Figure 3: a) Azimuthal stacks of traces from the 50m fracture spacing model. The traces represent azimuth stacks starting in the direction parallel to fracturing (top), and then increasing in 10 degree increments until normal to the fractures. The bottom trace shows the stack for the model without a fractured layer. b) Corresponding transfer functions.

Figure 4: a) Azimuthal stacks of traces from models with various fracture spacing . b) Corresponding transfer functions.

Figure 5. Schematic showing that the reflected energy from layers above a fractured zone will not be altered by the fractures. However, the energy reflected off layers below the fractured zone will acquire a ringing coda caused by fractures.

Figure 6: Polar plot of the azimuthal variation of scattering indices derived from the transfer functions of the 25, 35, 50 and 100m fracture spacing models. The scattering index is largest in the direction parallel to the fracture orientation. The largest scattering index is for the 35m fracture spacing, while the smallest shown is for the 25m spacing.

Figure 7. Profile through the Emilio PP data showing interval velocity log (left), interpreted seismic section (middle) and structural model (right) from Vetri et al, 2003.

Figure 8. Fracture orientations for the Emilio field from scattering index values showing an angular contrast in values larger than 5.

Figure 9. Map-migrated scattering index fracture directions (in blue) for the Emilio field (having angular contrast values >4). The black lines indicate faults derived from seismic data. The well locations are indicated by the round colored circles.

Figure 10. A comparison of the map-migrated scattering index fracture orientations (left panel copied and rotated from Figure 9) having high angular contrast values with the scattering index fracture directions for all CDPs which have not been migrated (right panel). The color legend at the top right indicates the fracture direction in hue and increasing angular contrast with intensity.

Figure 11. The left panel shows the fracture strike derived from PS anisotropy (Vetri et al, 2003) with its corresponding color-coded direction legend at the bottom left. The right panel shows the smoothed fracture orientations derived from the scattering index analysis in right side of Figure 10 with its corresponding color-coded legend at the top right. The black arrows indicate three fracture orientation trends.

Figure 12. The top set of diagrams show the well derived fracture information (from Vetri et al., 2003) – SHmax is generally the direction of fracture strike. The red arrow indicates the direction of SHmax for well 4. The middle three diagrams are close-ups of Figure 9 around the corresponding well locations showing

the agreement of the map migrated scattering directions with the well fracture directions. The bottom three diagrams show the histograms, in rose diagram format, of the map migrated scattering index directions around each of the wells.

Figure 1.

Figure 2.

Figure 3a.

Figure 3b.

Figure 4a.

Figure 4b.

**Down Going
Seismic Energy**

**Reflections
From Above**

**Reflections
From Below**

**Fractured
Zone**

Figure 5.

Azimuthal Scattering Indices for Four Fracture Spacings

Figure 6.

Figure 7.

Figure 8.

Faults Derived from Seismic and Scattering Index Fracture Orientation

Figure 9.

Figure 10.

PS Fast Azimuth –
Fracture Orientation

PP Scattering Index –
Fracture Orientation

Figure 11.

Figure 12.