Fractured reservoir delineation using multicomponent seismic data

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Abstract

The characteristic seismic response to an aligned-fracture system is shear-wave splitting, where the polarizations, time-delays and amplitudes of the split shear waves are related to the orientation and intensity of the fracture system. This offers the possibility of delineating fractured reservoirs and optimizing the development of the reservoirs using shear-wave data. However, such applications require carefully controlled amplitude processing to recover properly and preserve the reflections from the target zone. Here, an approach to this problem is suggested and is illustrated with field data.

The proposed amplitude processing sequence contains a combination of conventional and specific shear-wave processing procedures. Assuming a four-component recording (two orthogonal horizontal sources recorded by two orthogonal horizontal receivers), the split shear waves can be simulated by an effective eigensystem, and a linear-transform technique (LTT) can be used to separate the recorded vector wavefield into two principal scalar wavefields representing the fast and slow split shear waves. Conventional scalar processing methods, designed for processing P-waves, including noise reduction and stacking procedures may be adapted to process the separated scalar wavefields. An overburden operator is then derived from and applied to the post-stacked scalar wavefields. A four-component seismic survey with three horizontal wells drilled nearby was selected to illustrate the processing sequence. The field data show that vector wavefield decomposition and overburden correction are essential for recovering the reflection amplitude information in the target zone. The variations in oil production in the three horizontal wells can be correlated with the variations in shear-wave time-delays and amplitudes, and with the variations in the azimuth angle between the horizontal well and the shear-wave polarization. Dim spots in amplitude variations can be correlated with local fracture swarms encountered by the horizontal wells. This reveals the potential of shear waves for fractured reservoir delineation.

Introduction

Most carbonate reservoirs contain a finite population of natural fractures which dominate the permeability and control the fluid flow in the reservoirs (Aguilera 1980;...
Nelson 1985). Successful development of these reservoirs largely depends on the knowledge of the distribution of the fracture systems. Geologically speaking, fracture is a generic term for a planar discontinuity in rock due to deformation or physical diagenesis, such as crack, vein, joint and fault, with a scale length ranging from grain size to basin-wide. There is evidence that certain small-scale fractures may be stress aligned (Crampin and Lovell 1991) and are elastically anisotropic for seismic waves with sufficiently long wavelengths. These fractures, either having been initially open or subsequently closed due to mineralization, are important for fluid flow (Nelson 1985), and may be modelled using effective-medium theory (Hudson 1981; Schoenberg and Douma 1988); such fractures often have a scale length less than a tenth of the wavelength at the subseismic scale (Ebrom et al. 1990), and may be classified as microfractures as opposed to macrofractures.

A characteristic seismic response to the aligned-fracture system containing microfractures is shear-wave splitting, where the polarizations, time-delays and amplitudes of the split shear waves are related to the orientation and intensity of the fracture system. Thus it is possible to delineate fractured reservoirs and to optimize the development of the reservoir using shear-wave data. This has been confirmed by recent observations in southern Texas (Mueller 1991; Li and Crampin 1993a), and is illustrated in Fig. 1, where a P- and an SH-wave reflection section are shown over a known fracture zone confirmed by drilling (the rectangular area). The SH-wave is attenuated and forms dim spots across the fracture zone. In contrast, the P-wave is almost unaffected and shows continuous events across the zone. However, such applications require carefully controlled amplitude processing to recover properly and preserve the reflections from the target zone. Here an approach to this problem is suggested, and is illustrated with field data.

Over the last ten years, shear-wave data have been used in several cases to evaluate fractured reservoirs in the search for hydrocarbons. Multicomponent shear-wave reflection data have been acquired in a number of different areas for shear-wave studies (Alford 1986; Squires, Kim and Kim 1989; Lynn and Thomsen 1990). Three-dimensional multicomponent reflection data have also been acquired for characterizing fractured reservoirs (Lewis, Davis and Vuillermoz 1991). Thus, evaluating the merits of the shear-wave information and establishing a consistent processing sequence for extracting the information are important for the development of shear-wave exploration. Yardley and Crampin (1991) and Yardley, Graham and Crampin (1991) used synthetic examples to examine the viability of shear-wave polarizations and amplitudes in multicomponent VSPs and reflection profiles. Spencer and Chi (1991) and Li and Crampin (1993b) derived theoretical formulations for studying zero-offset shear-wave reflectivity. Alford (1986), Thomsen (1988), Li and Crampin (1993a) and others developed techniques for extracting shear-wave polarizations, time-delays and amplitude variations in multicomponent reflection data in the presence of anisotropy.

In all these studies only azimuthal anisotropy due to fracturing is considered since other types of anisotropy due to aligned pores and parallel bedding plane are less

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Figure 1. Comparison of the P- and S-wave responses in reflection surveys over a fracture zone (the rectangular area). The P-wave section shows continuous events, while the S-wave section shows broken events, forming a dim zone (courtesy of Teleseis Petroleum).

important for natural fractured reservoirs. Natural fractured reservoirs often exist in rocks with low matrix porosity and permeability, and anisotropy due to aligned pores is thus insignificant; for fractured reservoirs in shales, the anisotropy due to parallel bedding planes is less significant for near-vertical shear-wave propagations compared with fracture-induced anisotropy. In addition, azimuthal anisotropy is most common in sedimentary basins (Willis, Rethford and Belanski 1986; Bush and Crampin 1991).

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due either to fracturing or to a combination of fracturing with fine layering. Here, first
the information contained in shear-wave reflection data associated with azimuthal
anisotropy is reviewed, and then the relative merits of different characteristics for
fracture study are discussed. Following the discussion of the requirements for
amplitude processing, the multicomponent processing methods are presented, and a
case example is used to illustrate the ideas.

Shear-wave information in reflection surveys

A shear wave possessing a polarization orthogonal to its raypath contains more
information than a P-wave (Crampin 1985). The attributes of split shear waves,
diagnostic of fracture distributions, include the polarization of the leading split shear
wave, the time-delay between the two split shear waves, the differential reflectivity
upon interfaces, and the differential attenuation and scattering along the raypath. Here,
only the three commonly used attributes are considered: the polarization, time-delay
and reflectivity at normal incidence. Their relative merits are discussed and their
potentials for detecting fractures are compared.

Polarization

When a shear wave enters an effectively anisotropic medium containing vertical
fractures, the wave necessarily splits into two waves, travelling with different speeds.
For near-vertical propagation, the fast split shear wave polarizes parallel to the fracture
strike, and the slow wave polarizes nearly orthogonal to the fast wave (Crampin 1981).
Thus, in theory, one can infer the fracture strike of the underlying medium from shear-
wave seismic data recorded on the surface or in boreholes. However, this rule of thumb
has a few pitfalls in a real seismic survey.

First, there is a shear-wave window at the free surface (Booth and Crampin 1985).
When a shear wave is incident on the free surface beyond a certain critical angle,
differential attenuation and phase changes in reflected and converted waves cause
distortion of the incident shear-wave polarization. This critical angle, about 35–40°
measured from the vertical, depending on Poisson’s ratio and wavefront curvature,
defines the shear-wave window (Booth and Crampin 1985). The angle is about 35° in
most cases. Because of this, polarizations corresponding to shallow raypaths in a CDP
gather will be completely distorted as angles of incidence exceed the shear-wave
window.

The anisotropic effect in the overburden is a second hazard. A shear wave will
generally split whenever it passes through an anisotropic medium. Thus, if the
overburden is anisotropic, the polarization recorded on the surface is determined by the
anisotropic symmetry in the immediate near-surface; the anisotropic symmetry
information in the target is then concealed by that of the overburden. Since the near-
surface is often more anisotropic than the subsurface (Crampin and Love11 1991), it
will be very difficult to infer the fracture orientation of the reservoir from surface
recordings, although near-surface corrections (MacBeth et al. 1992) may be used. This is a major problem in the use of polarization information. Yardley and Crampin (1991) suggested that VSPs may be the best way to study target-orientated shear-wave polarizations. However surface data are still worth recording and processing for obtaining polarization information away from and between boreholes, and even before drilling, and for cost-effectively resolving spatial variations of rock properties.

**Time-delay**

The time-delay between the fast and slow split shear waves depends on the distance travelled and the magnitude of anisotropy encountered. Because the magnitude of anisotropy is mainly determined by the fracture intensity in the media, time-delay is thus a valuable attribute for the inference of fracture intensity from a seismic section. Time-delays are usually measured from the stacked sections of the fast and slow shear waves. The advantage of using the time-delay attribute lies in its simplicity. It is relatively easy to measure, and overburden anisotropy can be corrected simply by taking the interval time-delay between the top and bottom reflections of the target, and layer thickness can be handled simply by normalization. However, for a thin or weakly anisotropic reservoir, interval time-delays may be too small to resolve reliably, particularly if most of the anisotropy is in the overburden and near-surface; this is one of the major pitfalls in using the time-delay attribute. Also, time-delays contain little information about fracture orientations, which must be deduced from other attributes. Squires et al. (1989) and Lewis et al. (1991) presented examples of interpreting interval time-delays from field data.

**Normal reflectivity**

Thomsen (1988) suggested that the differential amplitudes between the fast and slow split shear waves may be used to identify fracture zones in stacked seismic sections. Anisotropy caused by microfractures affects the slow shear wave (with polarization perpendicular to the fracture strike) more than the fast shear wave (with polarization parallel to the fracture strike); increasing the fracture population density lowers the velocity of the slow shear wave and changes the impedance contrast, hence differentiating the reflection strength in the stacked fast and slow sections. This phenomenon is often referred to as ‘differential reflectivity’ at normal incidence, because stacked sections are often considered as seismic reflections at normal incidence. Mueller (1991) first presented an example using normal reflectivity to identify fracture swarms in the Austin Chalk in south Texas. Yardley et al. (1991) presented the theoretical modelling result of Mueller (1991). Note that anisotropy caused by macrofracture may affect both the fast and slow split shear waves (Liu et al. 1993).

Compared with other attributes such as the polarization and time-delay, the differential reflectivity at normal incidence is more a qualitative attribute than a
quantitative one. It tends to help in identifying more intensely fractured zones in the seismic section, instead of quantifying the exact values of the fracture intensity, although methods have been published to quantify the fracture intensity from the reflectivity (Spencer and Chi 1991; Li and Crampin 1993b). As this qualitative information is usually sufficient in most cases, the differential reflectivity at normal incidence is thus a very useful indicator for fractured reservoir delineation. The major advantages of using this attribute include: the interpretation is straightforward and similar to the traditional amplitude analysis; thin or weakly anisotropic reservoirs may be resolved better than with the polarization and time-delay attributes. The main difficulty, as with all amplitude-analysis techniques, lies in maintaining and recovering the true amplitude information during processing. Other pitfalls include the insensitivity to the fracture orientation and the lack of a quantitative definition of the fracture intensity.

So far three major attributes of the shear wavetrain have been discussed: the polarization, the time-delay and the differential reflectivity at normal incidence. Other attributes such as the offset-dependent reflectivity, attenuation and scattering, etc. are beyond the scope of this study. The processing sequence necessary for recovering the three major attributes is now discussed; this sequence is referred to as ‘shear-wave controlled-amplitude processing’.

Shear-wave controlled-amplitude processing

This approach to shear-wave controlled-amplitude processing involves a combination of both conventional and specific shear-wave procedures, as shown in Fig. 2. The conventional procedures are all scalar algorithms and applicable to scalar wavefields, while the specific shear-wave procedures are vector algorithms and applicable to a vector wavefield. The basic idea is to use the vector algorithms to separate the vector wavefield into the principal scalar wavefields which can then be processed separately by the scalar algorithms.

The conventional procedures include a conventional stacking sequence and a conventional amplitude-correction sequence. The conventional stacking sequence includes: statics correction, velocity analysis, normal moveout correction, stacking and other signal-enhancing routines, such as band-pass filtering and deconvolution. All these procedures are similar to those used in conventional P-wave processing (Yilmaz 1987). The conventional amplitude-correction sequence includes: compensation for spherical divergence (geometrical spreading), attenuation and other amplitude-dependent factors. All these compensations are similar to those suggested for P-wave AVO analysis by Yu (1985) and Castagna and Backus (1993). Both the conventional stacking and amplitude-correction sequences are designed only for one-component scalar wavefields (acoustic wavefields). As long as the vector shear-wavefield is properly separated into its characteristic scalar wavefields, the side effects of the conventional routines on the shear waves are small and can be neglected (Li, Mueller and Crampin 1993a). Details of these conventional processing methods are.
Figure 2. Flow diagram showing the sequence for shear-wave controlled-amplitude processing. The outlined boxes indicate specific shear-wave procedures for handling the vector wavefield; the plain boxes indicate conventional procedures as suggested for P-wave AVO analysis by Yu (1985).

The shear-wave procedures include multicomponent surface-consistent correction, multicomponent noise reduction, vector wavefield separation and overburden amplitude correction, which are designed specifically to deal with the multicomponent data. The multicomponent surface-consistent correction is a direct extension of Taner and Koehler’s (1981) method for one-component P-wave seismic data to multicomponent shear-wave data, and compensates for the multicomponent source and geophone response including source imbalance, geophone coupling and possible distortions due to interaction with the near-surface (Li 1994). The method for multicomponent noise reduction uses the polarization differences between noise and
signal to reduce coherent noise including ground roll, guided waves and converted waves; this is also called polarization filtering. [Kanasewich (1981) gives a detailed account of the theory and application of polarization filters, which will not be repeated here.] The traditional technique for separating split shear waves in surface seismic data is to rotate the multicomponent data matrix to decouple the split shear waves (Alford 1986); the technique for overburden correction is layer stripping (MacBeth et al. 1992). Here, a deterministic linear-transform technique (Li and Crampin 1993a) for separating the vector wavefields of split shear waves and a statistical approach for overburden correction are presented. These procedures are referred to as multicomponent data processing.

**Multicomponent data processing**

*Multicomponent data*

With different configurations of sources and receivers, up to nine-component data can be recorded consisting of three polarized sources and three polarized geophones (P-, SV- and SH-, or Z, X and Y for sources, and z, x and y for geophones (Fig. 3). Ideally, a full nine-component geometry is needed to describe the vector wavefield accurately. However, in practice, to minimize the cost of acquisition, several configurations of sources and receivers have been used depending on the purpose of the surveys. These include conventional one-component P-wave (the Zz-component) seismic survey for mapping geological structure (Yilmaz 1987), three-component acquisition (P-source recorded by P-, SV- and SH-receivers, or the Zz-, Zx- and Zy-components) in VSPs for correlating seismic horizons (Hardage 1991). Other combinations include two-component P- and SH-wave survey (the Zz- and Zy-components), and P- and SV-wave survey (the Zz- and S-components) for mapping geological structure and lithology (Dohr 1985).

![Figure 3. Data matrix for nine-component recording geometry. There are three orthogonal sources (X, Y, and Z) represented by the columns, and three orthogonal receivers (x, y, and z) by the rows. The shaded area represents the conventional five-component geometry (Alford 1986) studied in this paper.](image)

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In the 1980s, the study of seismic anisotropy led to the development of four-component (Xx-, Xy-, Yx- and Yy-components) and five-component (the four-components plus the Zx-component) surveys (Alford 1986), as well as total wavefield nine-component surveys (Squires et al. 1989). The purpose of these surveys is to investigate the viability of shear-wave splitting for reservoir characterization. Considering the cost of field acquisition, the five-component survey is a useful subset (the shaded area in Fig. 3). Under the assumption of weak anisotropy, the P-wave component (the &-component) is decoupled from the four shear-wave components (the Xx-, Xy-, Yx- and Yy-components). Thus, the processing of five-component data can be separated into two parts: the processing of the Zx-component and the processing of the shear-components. Here, the processing and interpretation of the four shear-wave components in the presence of anisotropy is mainly discussed. For processing of the P-wave data (the Zx-component), the reader is referred to Yilmaz (1987).

Assuming orthogonally polarized and vertically propagating split shear waves, shear-wave splitting can be simulated by a two-component eigensystem, with the eigenvectors representing the polarizations, and the eigenvalues representing the amplitudes, of the two split shear waves (Fig. 4a). For the four-component geometry (Xx-, Xy-, Yx- and Yy-components) as shown in Figs 4b and c, if the applied source motion is linearly polarized and any inconsistency in the source and geophone response can be compensated for (Li 1994), the recorded four-component data matrix can be written as (see also Alford 1986)

\[
D(t) = R^T(\alpha_G)R(\alpha)\Lambda(t)R(\alpha_S) = R^T(\alpha_G - \alpha)\Lambda(t)R(\alpha_S - \alpha),
\]

where \(D(t)\) is the data matrix, \(R\) is the orthogonal rotation matrix, and \(\Lambda(t)\) is the diagonal transfer function for the two split shear waves \(\varsigma S_1\) and \(\varsigma S_2\). We have

\[
D(t) = \begin{bmatrix} Xx(t) \\ Xy(t) \end{bmatrix}, \quad \Lambda(t) = \begin{bmatrix} \cos \alpha & \sin \alpha \\ -\sin \alpha & \cos \alpha \end{bmatrix},
\]

After applying geophone rotation to (1), the rotated data matrix \(D'(t)\) is shown in (2). Data matrix \(D'(t)\) then has two orthogonal eigenvectors at directions \(\alpha_G\) and \(90^\circ + \alpha\), respectively, and two eigenvalues \(\varsigma S_1\) and \(\varsigma S_2\), respectively, as shown in Fig. 4a. Note that the orthogonality of split shear waves is strictly true for phase propagation, and often is a good approximation only for near-vertical group propagation (Crampin 1981). [For non-orthogonal split shear-waves, see Li, Crampin and MacBeth (1993b).]

Figure 5 shows an example of data matrix \(D(t)\) from a reflection survey in South Texas. There are four shot records, forming a four-component data matrix.

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There is coherent energy in both the diagonal (the $Xx$- and $Yy$-components) and off-diagonal (the $XY$- and $Yx$-components) elements, indicating shear-wave splitting. This is a typical case of shear waves propagating in an azimuthally anisotropic medium: the split shear waves are coupled into all four components, with almost no P-wave energy. The purpose of processing is to determine the polarization angle $\alpha$ and to separate the split shear waves ($qS1$ and $qS2$) from the recorded data matrix $D(t)$.

**Split shear-wave separation**

To separate the split shear waves, we introduce four linear transforms (Li and Crampin 1993a)

$$\begin{align*}
\xi(t) &= Xx(t) - Yy(t), \\
\eta(t) &= Yx(t) + Xy(t), \\
\chi(t) &= Yx(t) - Xy(t), \\
\zeta(t) &= Xx(t) + Yy(t),
\end{align*}$$

or in matrix form (MacBeth and Li 1996),

$$\text{LTT}[D(t)] = \begin{bmatrix} \xi(t) \\ \eta(t) \\ \chi(t) \\ \zeta(t) \end{bmatrix} = I_A D(t) I_B + D(t),$$

where

$$I_A = \begin{bmatrix} 0 & 1 \\ 1 & 0 \end{bmatrix}, \quad I_B = \begin{bmatrix} 0 & 1 \\ -1 & 0 \end{bmatrix}.$$

$\text{LTT}$ represents the linear-transform operator in (4), $I_A$ and $I_B$ are switch operators which are derivatives of Pauli spin matrices (Altmann 1986). Applying the $\text{LTT}$ to (2),
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Figure 5. A shot data matrix acquired with two horizontal sources and two horizontal receivers in south Texas.

as angles $\alpha_s$ and $\alpha_c$ are often known in surface seismic surveys, we have

$$L_{T[T]}[D'(t)] = \begin{bmatrix} \xi(t) & \chi(t) \\ \eta(t) & \zeta(t) \end{bmatrix} = \begin{bmatrix} \cos 2\alpha & 0 \\ \sin 2\alpha & 1 \end{bmatrix} \begin{bmatrix} qS1(t) - qS2(t) \\ 0 \end{bmatrix} \begin{bmatrix} qS1(t) + qS2(t) \\ 0 \end{bmatrix}. \tag{7}$$

Thus, the time series $qS1(t)$ and $qS2(t)$ are separated from the static geometry factors $\alpha$ after transformation. The transformed vectors $[\xi(t) \ \eta(t)]^T$ and $[\chi(t) \ \zeta(t)]^T$ are eigenvectors representing linear-polarized motions in the time domain in the

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displacement plane. The rotation angle \( \alpha \) can be determined from vector \([\xi(t) \eta(t)]^T\) as the Jacobi rotation angle,

\[
\alpha(\tau) = \frac{1}{4} \tan^{-1} \left[ \frac{2 \sum_{t} \xi(t + \tau) \eta(t + \tau)}{\sum_{t} [\xi^2(t + \tau) - \eta^2(t + \tau)]} \right].
\]

The summation is over a chosen time window, or the entire recorded time, and \( \tau \) represents the starting point of the chosen window. If we apply (8) for each time-sample instantaneously (e.g. the length of the time window is one sample), then we obtain one angle for each sample. This is referred to as a polarization log or instantaneous polarization component (Li and Crampin 1991). The fast and slow shear waves can also be easily determined from the transformed vectors from (7),

\[
q_{S1}(t) - q_{S2}(t) = \xi(t) \cos 2\alpha + \eta(t) \sin 2\alpha,
\]

\[
q_{S1}(t) + q_{S2}(t) = \xi(t).
\]

The simple arithmetic of (4) and (5) and the resulting separation of time series from geometry factors in (7) are the main advantages of the linear-transform technique.

Thus the procedures to separate split shear waves from the four-component data matrix \( D(t) \) can be summarized as follows:

1. Calculate \( D'(t) \) using (2), as angles \( \alpha_5 \) and \( \alpha_6 \) are often known in surface seismic surveys.
2. Calculate the transformed matrix \( \text{LTT} \{D'(t)\} \) using (5).
3. Calculate the instantaneous polarization \( \alpha(\tau) \) using (8), and the instantaneous polarization \( \alpha(\tau) \) may be displayed in colour to quantify the polarization variations (Li and Crampin 1991; Li et al. 1993a).
4. Solve (9) for the principal time series \( q_{S1}(t) \) and \( q_{S2}(t) \).

Figure 6 shows the separated split shear waves \( q_{S1} \) and \( q_{S2} \) and the residual components after applying the above sequence to the data matrix in Fig. 5. The diagonal elements are the separated fast and slow split shear waves \( q_{S1}(t) \) and \( q_{S2}(t) \), the off-diagonal elements are the residual components containing little coherent signal. Note that here we only selected the separated split shear waves \( q_{S1} \) and \( q_{S2} \) to illustrate the above sequence, and the instantaneous polarization component calculated by step 3 of the above sequence is not shown. After separation, the \( q_{S1} \) wave, the \( q_{S2} \) wave and the instantaneous polarization components can then be treated as scalar wavefields and processed by conventional scalar methods such as those used for processing P-waves (e.g. Squires et al. 1989; Lewis et al. 1991; Li et al. 1993a). However, apart from those conventional scalar methods, carefully controlled amplitude processing is required to obtain optimum stacked sections and to recover the shear-wave information in the zones of interest. This includes conventional amplitude corrections (Yu 1985; Castagna and Backus 1993), as discussed in the previous section and shown in Fig. 2, and a specific shear-wave overburden correction.
Figure 6. The shot data matrix after vector wavefield decomposition, obtained by applying the linear-transform technique to the shot data matrix in Fig. 5.

**Overburden correction**

Overburden amplitude correction compensates for anisotropy, attenuation and scattering effects in the overburden. Deterministic techniques have been developed for some of these corrections such as the layer-stripping method (Winterstein and Meadows 1991; MacBeth et al. 1992) for correcting anisotropic effects in the overburden, and the multicomponent deconvolution algorithm (Zeng and MacBeth 1993) for correcting linear or non-linear anomalies in the near-surface and overburden.
Satisfactory results have been obtained in multicomponent VSPs (Winterstein and Meadows 1991; Zeng and MacBeth 1993). However, these techniques are, in general, unsatisfactory when applied to surface data because of the lower S/N (signal-to-noise) ratio of surface data compared with VSPs. As a result, successful applications to multicomponent surface seismic data have not yet been reported. Here, a simple and effective statistical approach is taken to implement overburden correction in surface seismic data.

After compensating for the source and geophone response and separating the split shear waves, we apply the conventional amplitude correction and stacking sequence to the separated $qS_1$ and $qS_2$ components (Fig. 2). The amplitude of the target horizon in the stacked $qS_1$ or $qS_2$ section may be written as (see also Li 1994)

$$a_{th}(t) = \lambda_{obu}(t) * m_{th}(t) * \lambda_{obd}(t),$$  

where $a_{th}(t)$ is the amplitude of the target horizon in either the stacked $qS_1$ or $qS_2$ section depending on the input, $m_{th}(t)$ is the target response to the $qS_1$ or $qS_2$ wave, $\lambda_{obu}(t)$ is the overburden propagator for the up-going $qS_1$ or $qS_2$ wave, $\lambda_{obd}(t)$ is the propagator for the down-going $qS_1$ or $qS_2$ wave, and $\lambda_{obd}(t) = \lambda_{obu}(t) = \lambda_{ob}(t)$ under the assumption of reciprocity. The symbol $*$ denotes deconvolution. The purpose of the overburden correction is to recover $m_{th}(t)$ from $a_{th}(t)$, which requires the determination of $X_{th}(t)$. Similarly to the conventional surface-consistent amplitude correction (Taner and Koehler 1981), this overburden correction can be implemented as multiplying traces by scalars (Li 1994). In other words, (10) may be, in practice, simply written as

$$d(t) = \lambda_{obu}(t) * m_{th}(t) * \lambda_{obd}(t),$$

where superscript $k$ represent the $k$th CDP location, $\lambda_{obu}(t)$, is a frequency-independent and time-invariant scaling factor for the $k$th CDP trace, representing the effects of the overburden. The scaling factor $\lambda_{obu}(t)$ may be determined from the root-mean-square (rms) amplitude of the overburden horizon in the stacked section after applying a smoothing filter to improve robustness:

$$\lambda_{obu}(t) = \frac{1}{2L + 1} \sum_{j=-L}^{L} f_{ob}^{h+i},$$

where $2L + 1$ is the length of the smoothing filter, and $f_{ob}$ is the rms amplitude of the overburden horizon at the $k$th CDP location. In practice, scaling factors for the $qS_1$ and $qS_2$ sections may be averaged to produce a common overburden scaling factor for both sections, and this common scaling factor is then applied to the whole trace. Figures 7 and 8 illustrate these procedures for the overburden correction.

Figure 7 shows the stacked $qS_2$ section before (Fig. 7a) and after (Fig. 7b) the overburden correction. The rectangles mark the significant dim spots along the Austin Chalk; the heavy solid lines mark two time windows representing the overburden and the target (the Austin Chalk). In Fig. 7b, before overburden correction, there are no...
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Figure 7. A comparison of the stacked qS2 section (a) before and (b) after overburden amplitude correction. The heavy solid lines mark two time windows representing the overburden and the Austin Chalk, respectively; the rectangles mark significant dim spots after overburden correction.

clear and significant dim spots within the rectangles in the Austin Chalk. In contrast, in Figure 7b, after overburden correction, there are clear and significant dim spots within the rectangles along the Austin Chalk.

In order to examine the amplitude variation and demonstrate the effects of the overburden in more detail, the rms amplitudes within each window for each CDP location are calculated. This is shown in Figs 8a and b corresponding to Figs 7a and b, respectively. Without overburden correction, as shown in Fig. 8a, the amplitude-curves in the overburden (the dot-dashed line, $\gamma_{ab}^d$) and the Austin Chalk (the dotted line) are dominated by the overall trend of variations (the solid line), representing the effects of the overburden. The local variations are not clearly separated and are difficult to
Figure 8. A comparison of the windowed rms amplitudes (a) before and (b) after overburden amplitude correction. (a) and (b) are calculated from the time windows in Figs 7a and b, respectively. The dot-dashed line is the rms amplitude in the overburden window; the dotted line is the amplitude in the Austin Chalk window; the heavy solid line through them in (a) is the average amplitude representing the effects of the overburden. The long-dashed straight line represent the mean amplitude; the arrows mark significant dim spots.

interpret for dim or bright spots. However, after removing the overall trend of variations (the solid line), as shown in Fig. 8b, the local variations in amplitudes are enhanced; three zones (dim spots) where the amplitudes of the Austin Chalk (the dotted line) are significantly below the mean curve (the long dashed line) can be identified in Fig. 8b, marked by three arrows, while they are hardly visible in Fig. 8a before overburden correction. These three dim spots marked by the arrows in Fig. 8 correspond to the dim spots within the rectangles in Fig. 7 (the rectangle on the right contains two dim spots).

Note that the use of a smoothing filter in calculating the overburden scaling factor assumes that the overburden scaling factor is consistent, or varies smoothly for adjacent CDP locations (the overburden-consistent assumption (Li 1994)). If the overburden contains steep structures, the overburden scaling factor may vary sharply, because of possible sharp changes of the ray geometry for adjacent CDPs, and the length of the smoothing filter should be restricted and selected carefully. If the overburden varies smoothly, the restriction in choosing the length of the smoothing
filter can be relaxed. In the case shown in Figs 7 and 8, the overburden contains horizontal layers, and a large smooth filtering of 21 CDP points \((L = 10)\) is used.

To sum up, the procedures for overburden correction are:
1. Choosing time windows to define the overburden and the target, making sure that the time windows cover good quality events.
2. Calculating the rms amplitudes over the defined windows.
3. Deriving the overburden scaling factor using a smoothing filter or least-squares fit \((12)\).
4. Applying the scaling factor to both the stacked \(qS1\) and \(qS2\) sections \((11)\).

Field data example

The example is a four-component surface seismic survey from south Texas, USA. Two orthogonal horizontal sources (in-line and cross-line) are recorded by 12 1 in-line channels and 12 1 cross-line channels with a 50 m (165 ft) station interval. The sources were vibrated at alternate stations. A split spread with 12 1 in-line and cross-line channels on each side was used. The shot data matrix in Fig. 5 displays coherent energy in the off-diagonals, indicating typical shear-wave splitting. In the study area, oil is produced from the fractured Austin Chalk which has low matrix porosity. The fluid flow in the Chalk is wholly dependent on fractures (Mueller 1991). Li et al. (1993a) discussed the general shear-wave characteristics in this area and concluded that the overall anisotropy in this area can be correlated with the oil production in the Austin Chalk. Here, it is further demonstrated that amplitude dim spots in the seismic section may be correlated with local fracture swarms indicated by horizontal wells. The oil production may be correlated with variations in shear-wave polarizations, time-delays and amplitudes. This information reveals the potential to identify local fracture zones from local variations in shear-wave amplitudes, and to optimize target-orientated horizontal drilling.

Field information

Figure 9 is a survey map showing the location of the survey line and the distribution of the horizontal wells in the study area. The survey line lies north-south, at about 40° from the regional fracture strike. There are several horizontal wells in the area, marked by circle-dashed lines, where the big open circle at one end indicates the start of a well, and the small solid circle at the other end indicates the end of the well. All wells were drilled horizontally through the Austin Chalk. The three wells close to the line and with similar horizontal distance, identified as W 1, W2 and W3, were selected for study. Well W1 runs NW-SE and at about 60° from the regional fracture strike; W2 runs SW-NE and approximately parallel to the strike; W3 runs SE-NW and approximately perpendicular to the fracture strike. The production rates of the three wells are shown in Table 1. Among the three wells, W 1 is most productive, W2 is least productive and W3 is moderately productive.

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Figure 9. A survey map showing the location of the survey line studied and the distribution of the horizontal wells in the study area. The circle-dashed lines are projection of the horizontal well on the surface: the big open circle is the start of a well, the small solid circle is the end of the well. W1, W2 and W3 are the three wells selected for study, the dashed lines project the horizontal wells to the survey line along the fracture strike.

If the hydrocarbons in all fractured reservoirs penetrated by the horizontal wells have similar viscosity, the production rate (flow rate) of a horizontal well is, to some extent, determined by the number of fractures encountered by the well. This is in turn determined by the length and azimuth of the horizontal well and the fracture intensity of the zone penetrated by the well. Bearing this in mind and comparing Fig. 9 with Table 1, one can immediately make the following observations:

1. All three wells yield commercial production, presumably because local fracture swarms are present at all three sites.

2. W2 produced only half the amount produced by W3 during a similar period although they are drilled into the same trend of fracture swarms. This difference in production could arise because wells drilled parallel to the fracture strike intercept fewer fractures than wells drilled perpendicular to the fracture strike.

3. W1 has substantially higher rates of production than W3, despite W1 and W3 having similar spatial lengths and azimuths, and W3 being more favourably orientated. This could be due to either the zone penetrated by W1 being more heavily fractured than the zone penetrated by W3 or W1 penetrating more fracture swarms than W3. However, it is worth noting that there may be other possible interpretations as to why well W1 has substantially higher rates of production than W3. One possibility is that the fractured zone penetrated by W3 on the southern end of the survey line in Fig. 9
Table 1. Oil production records of the three horizontal wells $W_1$, $W_2$ and $W_3$ in Fig. 9. Data are supplied by Amoco Production Company. Note that the regional fracture strike is at $N40^\circ E$. Thus, wells $W_1$ and $W_3$ were drilled nearly perpendicular to the dominant fracture strike, while $W_2$ was drilled parallel to the fracture strike.

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Azimuth (degrees)</th>
<th>Horizontal Distance (Feet)</th>
<th>Maximum Barrels Per Day</th>
<th>Cumulative Production (BBLS)</th>
<th>Period (months)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$W_1$</td>
<td>$N25^\circ W$</td>
<td>3000</td>
<td>600</td>
<td>108000</td>
<td>14</td>
</tr>
<tr>
<td>$W_2$</td>
<td>$N40^\circ E$</td>
<td>2000</td>
<td>300</td>
<td>37000</td>
<td>19</td>
</tr>
<tr>
<td>$W_3$</td>
<td>$N50^\circ W$</td>
<td>3000</td>
<td>370</td>
<td>74600</td>
<td>21</td>
</tr>
</tbody>
</table>

was depleted by nearby wells. Although the production rates imply the presence of local fracture swarms, a more accurate and confident assessment of the actual fracture intensity encountered by the horizontal wells requires a more complete analysis of the production data including depletion curves, total produced fluids, oil cut, pressure data, etc.

Next the variations in the shear-wave attributes including the polarization, time-delay and amplitude are examined, and their correlations with the production rates and with the above observations are investigated. It is demonstrated that the presence of local fracture swarms and the variations in production rates can be correlated with the variations in shear-wave attributes.

**Polarization variations**

The procedure to quantify the polarizations is as follows:

1. The polarization angle $\alpha$ is calculated for each time sample and each trace from the shot data matrix using equation (8), so that a polarization trace for each source-receiver offset is obtained, forming a shot record of instantaneous polarization.

2. These polarization shot records are then sorted into CDP gathers (polarization gathers), and a simple stacking sequence ($NMO$ and statics correction and stacking) is then used to stack these polarization gathers, so that a single stacked polarization trace is obtained for each CDP gather of polarizations.

3. The stacked polarization trace for each CDP can then be displayed in colour for interpretation (Li and Crampin 1991; Li et al. 1993a).

Note that any abnormal polarization changes in far-offset traces have to be muted before stacking. Coherent polarizations will then be enhanced, and noise will be suppressed by stacking. Here, the colour section of stacked instantaneous polarization is not shown; instead, the window-average polarization angles for each CDP location are shown in Fig. 10. The solid line is measured from a time window covering only the Austin Chalk as shown in Fig. 7; the dotted line is measured from a time window covering the whole data. The two curves are close to each other, which implies that
polarization measurement is relatively stable. The overall polarization is about 40° as indicated by the long dashed line; this agrees with the overall fracture strike determined from the regional stress field. In the zones indicated by the arrows, some lateral variations can be observed: at CDPs around 251, the average polarization is about 40°, while at 351, it is about 30°. However, these variations are too small to alter the relationship between the well azimuth and fracture strike. This implies that the higher production in W 1 is not due to lateral variations in fracture strike in favour of W1. Apart from the overall information, the local variations in the polarizations in Fig. 10 are difficult to associate with any physical meaning.

Time-delay variations

Determining the time-delays from surface seismic data usually involves horizon tracking. Here, the horizons in the stacked \( qS1 \) and \( qS2 \) sections were first tracked. Then the three best horizons were selected. These are shown as H1, H2 and H3 in Fig. 1 la and marked in Fig. 12, for computing interval time-delay and interval percentage anisotropy. H0, the interval between the surface and horizon H1, represents the near-surface; H12, the interval between horizons H1 and H2, contains the overburden as defined in Fig. 7; H23, the interval between H2 and H3, contains the target zone, the Austin Chalk. Note that both the overburden and target intervals here are thicker than those in Fig. 7. This is because a large window is preferred in order to quantify the interval time-delay reliably, whereas a small interval is preferred to quantify the amplitude variation. The interval time-delay and interval percentage anisotropy are calculated using the following equation:

\[
\Delta t_i = t_i^{qS2} - t_i^{qS1}; \quad \epsilon_i = \Delta t_i - \Delta t_{i-1}; \quad \epsilon = \epsilon_i/(t_i^{qS2} - t_i^{qS1}),
\]

Figure 10. Polarization angles measured using the linear-transform technique. The solid line is measured from the time window containing Austin Chalk in Fig. 7; the dotted line is from the whole data. The long-dashed straight line at 38° represents the overall polarization angle which, with an allowance of ±3°, appears at most CDP locations. The arrows are the same as in Fig. 8.
where $\Delta t_i$ is the time-delay for the $i$th horizon, $t_{0S1}^i$ and $t_{0S2}^i$ are the zero-offset two-way traveltimes of the $i$th horizon for the $qS1$ and $qS2$ waves, respectively, $\varepsilon_r$ and $\varepsilon$ are the interval time-delay and interval percentage anisotropy, respectively, for the interval between the $(i-1)$th and $i$th horizons.

Figures 11b and c show the calculated time-delay and percentage anisotropy for the three intervals: the near-surface interval HO1 (dot-dashed lines), the overburden
Figure 12. The stacked qS1 and qS2 wave sections, (a) and (b) respectively, using the processing sequence in Fig. 2. W 1, W2 and W3 are horizontal wells; the small bars represent the azimuths of the wells; the bars in the far right indicate the fracture strike; the rectangles are the same as in Fig 7; H1, H2 and H3 mark the horizons in Fig. 11 a.

interval H12 (dotted lines) and the target interval H23 (solid lines). One can clearly see that most of the anisotropy is in the near-surface and the overburden: an average of 3% anisotropy (30 ms time-delay) in the near-surface, another 2.5% (20 ms delay) in the overburden, and only 1.5% (15 ms delay) in the large target interval (the long-dashed straight lines showing the average anisotropic values in the target). A large anisotropy in both the near-surface and the overburden makes it very difficult, if not impossible, to
quantify the interval time-delays over a target with small anisotropy. As demonstrated here, a large interval must be taken to quantify the time-delays. If a small interval were selected covering the Austin Chalk only, the interval time-delay would be less than two or three samples and be too small to pick up reliably and accurately. Despite the large interval, the scatter in the measurements of the target zone is still greater than those of the near-surface and the overburden. Because of this, local variations in time-delays are difficult to interpret. Some overall trends in lateral variations may be observed in Figs 11 b and c: the average anisotropy in the target H23 (the solid line) is about 1.5% from CDPs 230 to 310, and reduces to 1.0% from 310 to 360. These lateral variations may not be associated with the anisotropy in the Austin Chalk because of the large interval selected. Nevertheless, in general, it shows that the region of CDPs higher than 301 is less fractured than the region of CDPs lower than 301. This may also be one of the reasons why W3 produces less oil.

Amplitude variations

As shown in Figs 7 and 8, an overburden correction is essential to recover the amplitude variations in the target zone. The final stacked qS1 and qS2 wave sections, after the overburden correction has been applied, are shown in Fig. 12. The rectangles, as in Fig. 7, mark the dim spots. The one on the right contains two dim spots from CDPs 235 to 245 and 260 to 275, respectively; the one on the left contains one dim spot from 245 to 255. All these dim spots correspond to the arrows in Fig. 8. To see how the horizontal wells intercept these dim spots, the horizontal wells are projected on to the survey line along the fracture strike as shown in Fig. 9. The projected wells are then superimposed on the seismic sections as shown in Fig. 12. Comparing Figs 9 and 12 shows that W1 spreads from 225 to 265 and intercepts two dim spots, W2 is right at the edge of the third dim spot (CDP 370), and W3 spreads from CDPs 355 to 395 and intercepts part of the third dim spot (355 to 365). This demonstrates that there is a correlation between the dim spots in the seismic sections and the horizontal wells in this study area. As indicated by their commercial production rates (Table 1), the three horizontal wells most probably encountered certain kinds of local fracture swarms.

Thus it seems that there is a correlation between the dim spots in the seismic sections and the local fracture swarms encountered by the horizontal wells in this area. Note that amplitude dim spots are only a qualitative indicator of fractured zones, and other independent production information, such as reservoir depletion time, pressure data, and logging information, such as mud log, dip metre, imaging logs, are required to quantify the fracture intensity. Also note that here dim spots appear in both the qS1 and qS2 sections. This implies the presence of macrofractures which attenuate both the fast and slow split shear waves (Liu et al. 1993), or two hydraulically effective orthogonal fracture sets at these locations (M. Mueller of Amoco, pers. comm.).

To summarize, Well W1, drilled at approximately 60° to the fracture strike (Figs 9 and 10), in a relatively more fractured area (Fig. 11) and into two dim spots (Fig. 12), is most productive; W2, drilled approximately parallel to the fracture strike (Figs 9 and 10),
in a relatively less fractured area (Fig. 11) and at the edge of a dim spot (Fig. 12), is least productive; W3, drilled approximately perpendicular to the fracture strike (Figs 9 and 10) and in the same area as W2 but into part of a dim spot (Fig. 12), is moderately productive.

Discussion and conclusions

The information content of the shear-wave train has been examined, the processing methods for extracting this information has been presented, and their applications illustrated with a field data example. These show that the local variations in shear-wave amplitudes may be used to delineate fracture zones. In contrast, local variations in polarizations and time-delays are difficult to interpret and may be less informative in practice. However, they do give reliable overall information about the fracture strike and intensity in the survey area. Overall polarization variations can be calculated using the linear transform technique for four-component seismic data. Interval time-delay may be obtained by using a horizon-tracking facility in an interpretation workstation, which is more reliable than using the cross-correlation method. However, recovering the amplitude information of the target requires carefully controlled amplitude processing. This may be achieved by a combination of conventional and specific shear-wave processing procedures as shown in Fig. 2, of which the decomposition of the vector wavefield and overburden amplitude correction are essential. A linear-transform technique may be used for vector wavefield decomposition as shown in (1)-(9), and a statistical method may be used for overburden correction as demonstrated in (10)-(12) and in Figs 7 and 8.

The conclusion is that shear waves acquired with multicomponent sources and receivers show characteristic features which can help in determining the distribution of fractures. These shear waves can be analysed under an effective equivalent eigensystem with the eigenvectors and eigenvalues representing the polarization directions and amplitudes of the shear waves respectively. Controlled amplitude processing, particularly vector wavefield separation and overburden correction, is essential for preserving the characteristics of shear-wave splitting. As shown in the reflection data from south Texas, dim spots in stacked sections of fast and slow split shear waves can be correlated with fracture swarms as indicated by horizontal wells. The number of fractures intercepted by a horizontal well, which determines the oil production rate, can be qualitatively interpreted from the variations in shear-wave time-delay and amplitude. In conclusion, shear-wave splitting in multicomponent data provides a useful phenomenon for delineating fractured reservoirs.

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