Fracture mapping by near offset RMO analysis of HTI medium using 2D data

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Abstract

An anisotropic fractured medium can cause large residuals in a gather when NMO correction is performed using isotropic earth model. Residual NMO (RMO) can be further used to characterize the fracture (or anisotropy) parameters. In this paper we develop a simple scheme is to utilize RMO to derive two major fracture parameters (δ^h and azimuth φ). Our scheme requires 3D or multiazimuth data to derive these fracture parameters uniquely. We overcome the limitation due to lack of 3D data with the help of geostatistics. Well log derived sparse data sets are used to determine δ^h for the entire target horizon. Then using our RMO analysis equation and the kriged δ^h values, fracture strike maps are prepared for the horizon. Application of this technique to a dataset from Gulf of Mexico results in a fracture map which shows a trend parallel to the major fault system present in this area. This observation is in agreement with other independent observations from the area.

Introduction

After several decades of ground breaking research on seismic anisotropy, the major practice in exploration seismic data processing in the industry is still based on the isotropic assumption. Anisotropy is not generally considered in seismic data processing primarily due to the common belief that its effects are restricted to far offsets. In general the far offset seismic data gets affected by NMO stretching (even in the isotropic cases). In isotropic and anisotropic media far offsets show non-hyperbolic moveout and therefore, far offset traces are generally muted prior to stacking. The belief is that a good stack can always be prepared using isotropic processing even when the medium may be anisotropic.

A major flaw of the above approach is that it may result in an erroneous velocity model. The assumption that effects of anisotropy are limited to far offsets is wrong. To the contrary, several researchers show that theoretically, fracture characterization from a transversely isotropic medium with a horizontal axis of symmetry (HTI) or from an orthorhombic medium can be computed from the near offset NMO velocity information alone (Grechka and Tsvankin, 1999; Bakulin et al., 2000; Vasconcelos and Tsvankin, 2006) when azimuthal variations are taken into consideration. However, if multi azimuth/3D data are not present, then the process requires either a priori knowledge of fracture orientation or of anisotropic parameters. Nonetheless, even when far offset data are muted, the signature of anisotropy still persists in the near offset gathers and can be used for deriving anisotropic information.

In this paper we present a case study where 2D seismic data are processed using the isotropic assumption, even though several independent studies (FMS image, shear wave splitting etc.) show that the medium is anisotropic due to the presence of vertical fractures. At those sparse locations, fracture orientation and anisotropic parameter estimation have also been made from well log measurements. In this scenario we utilize isotropically over-corrected CMP gathers (Residual NMO or RMO) for the short offsets and determine the velocity uncertainty at each CMP location utilizing the short offset effect of anisotropy. Many researchers have shown that RMO analysis of HTI media can be used for fracture characterization, but only for cases using full offset (Li, 1999; Kozolov and Varivoda, 2005; Wang et al., 2007). Whereas our study utilizes short offset information for velocity uncertainty estimation, considering the fact that long offset data are generally muted and cannot be used for practical purposes. We associate the derived velocity uncertainty with the azimuth angle of anisotropy (or fracture strike) and the anisotropic parameter, δ^h (h stands for HTI). Then using the independently known δ^h values at the sparse locations, we prepare an exhaustive map of δ^h for the entire study area with the help of a geostatistical method (Ordinary Kriging). Exhaustive velocity residual and a δ^h map are then used to prepare a fracture orientation map of the study area.

Generally it is impossible to perform fracture characterization when multi-azimuth data is not present by making the problem underdetermined. A major advantage of geostatistics is that it handles the underdetermined problems by providing initially unavailable data using a statistical sense. It also provides the errors of the statistically estimated data to quantify the range of uncertainty present in the analysis. Thus in this paper, absence of 3D data does not restrict the job of fracture estimation. We utilize novel geostatistical tools to fill the gap of unavailable data and are able to perform our 1st order fracture characterization along with the estimate of uncertainty in the process.

In this paper we describe how a velocity uncertainty map can be prepared from RMO analysis and how it can be related to the anisotropic azimuth and δ^h parameters. We also present a case study of fracture mapping using short offset RMO analysis.

Method of RMO analysis

For an isotropic earth model in seismic data processing, the relationship between two-way traveltime (TWT) and offset (x) is generally represented by the Dix (1955) equation. Partial differentiation of the Dix (1955) equation for a fixed offset, can relate the uncertainty in TWT to the uncertainty in estimated NMO velocity by the following equation:

$$\partial V = -V^3_{NMO} t \partial t / x^2 \tag{1}$$

where, ∂V is the velocity uncertainty related to the traveltime residual (∂V) at a particular offset x after NMO correction (residual NMO effect) using a velocity VNMO. Thus by estimating ∂t from the residual moveout for a particular offset x, and putting the NMO velocity in equation 1, we can determine the velocity ambiguity (∂V) at each CMP location. The traveltime curve for P-wave reflection in an HTI medium can be described by the following equation (Tsvankin and Thomsen, 1994):

$$t^2 = t_0^2 + \frac{x^2}{V_{NMO}^2} + \frac{A_4 x^4}{1 + Ax^2}, \tag{2}$$

where for weak anisotropy (Tsvankin, 1997):

$$V^{h^2}_{NMO} = V^{h^2}_0 (1 + 2\delta^h \cos^2 \varphi), \tag{3}$$

and V_0^h is the vertical velocity (obtained from well log data), δ^h is one of the anisotropy parameters (Tsvankin, 1997), φ is the azimuth angle between the principal axis and the seismic inline, and A4 and A are functions of the other anisotropy parameters and azimuth. A mismatch between isotropic and anisotropic traveltimes at far offsets is due to the third term of equation 2. However when far offsets are muted, we can still observe a mismatch between the traveltime curves for isotropic and anisotropic media. This mismatch is due to the difference between isotropic and anisotropic NMO velocities. It is evident from equation 3, that when δ^h is zero (medium is isotropic), the NMO velocity of the HTI medium becomes the isotropic velocity. So near offset mismatch between anisotropic and isotropic media depends on the parameters δ^h and azimuth φ. To illustrate this, we first simplify equation 4 for a small value of δ^h (assuming weak HTI medium) and normalize it with the vertical velocity to obtain:

$$\frac{V^h_{NMO} - V^h_0}{V^h_0} = \frac{\partial V}{V^h_0} = \delta^h \cos^2 \varphi \tag{4}$$

If we consider ∂V in equation 4 to be the same as ∂V in equation 1, (since vertical velocity and NMO velocity are the same when the medium is isotropic), then the velocity ambiguity normalized by the vertical velocity obtained from well logs is a function of anisotropic parameter δ^h and azimuth angle φ. Now if we consider that the magnitude of δ^h is known from some independent study, then the azimuth φ, and thus the strike direction of the fractures (90°-φ), can be calculated at every CMP location.

For very small offset, even an isotropic equation (Dix equation) can fit anisotropic data. Near offset for our study is defined as the offset from where mismatch starts between a CMP gather and Dix equation. Thus we can eliminate the noisy far offset data and still perform fracture mapping from RMO analysis.

It is impossible to determine unique values of φ and δ^h separately from equation 4 if we do not know the value of one of the parameters (in the absence of multi-azimuth data). The values of δ^h are available at sparse locations within our study area. At those locations, fracture strike information is also available. We use Ordinary Kriging (OK) to populate δ^h values in the entire region. We prefer OK because of its natural independence of prior mean value (Goovaerts, 1997). A covariance model or semivariogram model for the OK is prepared from the sparse δ^h values present in the study area, which is then used for further kriging. Once an exhaustive δ^h map is prepared, a fracture orientation map can be easily prepared using the velocity uncertainty and equation 4. Kriging also provides estimate of variance at each CMP location. Those estimated variance can be further utilized to estimate uncertainty associated with derived fracture strike.

Field Data Example

The study area is located on the continental shelf in the Gulf of Mexico, covering an area of ~35 sq. km. This field produces from the Lower Paleocene-Upper Cretaceous and Middle Eocene reservoirs. To date, twenty wells have been drilled. From fifteen of them, shear wave splitting data are available. We perform our analysis on the Lower Paleocene-Upper Cretaceous level, which is the main reservoir and the top anisotropic medium. At this level, the trap is of a structural type produced by Lower Miocene age compression forces, bounded by reverse faults and also affected by salt tectonics. The reservoir is composed of breccia with microcrystalline dolomite fragments and partially dolomitized intraclasts. The porosity is secondary and intercrystalline with fractures and dissolution cavities.

The seismic dataset used in this study is migrated using a prestack time migration (PSTM) algorithm employed in common-offset domain assuming isotropy. Despite our best efforts toward velocity picking, PSTM leaves large residuals (figure 1) in time migrated moveout corrected common image gathers. Residual moveout shows typical 'hockey stick' effects which we consider to be due to anisotropy (Taner et al, 2005).

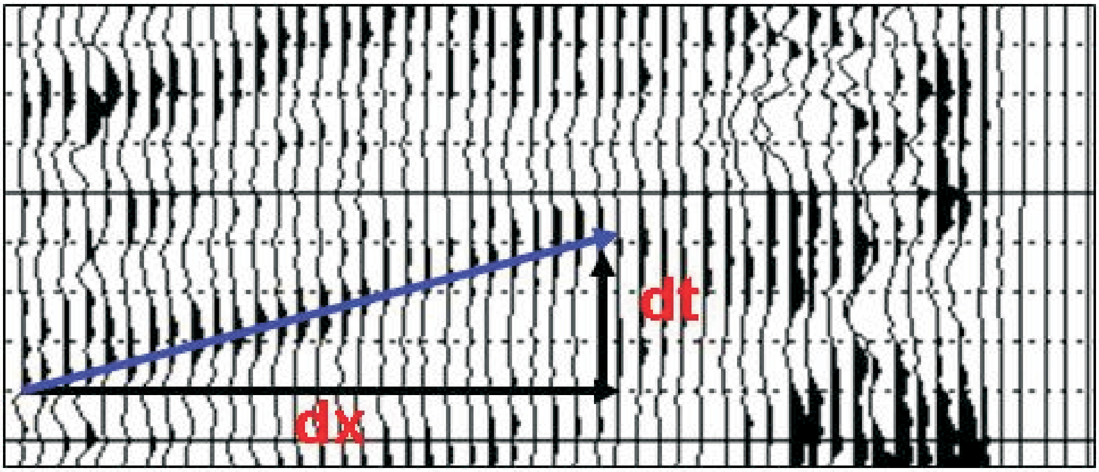

Fig 1 Typical prestack time migrated gather used in this study. PSTM is performed using the isotropic assumption. High magnitude residuals in the form of 'hockey sticks,' may indicate the anisotropic nature of the medium. For residual TWT calculation, the overcorrected portion of the seismograms is fitted with a straight line (blue line) up to a fixed near offset (dx). dt is then estimated from the slope of the straight line.

For the purpose of RMO analysis, we pick the residual TWT (∂t) at each CMP location by fitting a straight line to the overcorrected portion of the gathers. We use picked amplitudes up to an offset corresponding to ~30° to validate our near offset approximation determined in the theory. The process of picking dt is shown in Figure 1.

In a similar way, ∂t is estimated for the entire inline, then the entire horizon. The ∂t values for the entire horizon are then converted into the normalized velocity residual using equation 1 (Figure 2).

Accurate estimation of ∂t is typically performed by cross-correlating near and far offset data or using some standard software, where special picking is permitted (Kozolov and Varivoda, 2005). The same method can also be applied here, but our residual TWT estimate process is simpler than any other known methods.

Now we assume that the velocity uncertainty observed in figure 2 is a function of anisotropic parameter δ^h and the azimuth angle (equation 4). It is evident from equation 4 that the solutions for δ^h and φ from a single traveltime residual are non-unique. To overcome this difficulty we utilize the known δ^h values at sparse locations and perform ordinary kriging. Ordinary kriging is preferred over simple kriging as we do not want to bias our estimation of δ^h by providing an external mean information. For the purpose of ordinary kriging, we first generate the experimental semivariogram of δ^h using GSLIB software (Geostatistical Software Library and User's Guide, Deutsch and Journel, 1998) and model it. For modeling, we use a typical nested combination of anisotropic structures and Gaussian models (Figure 3). Then ordinary kriging is performed to populate the entire study area with δ^h values (Figure 4).

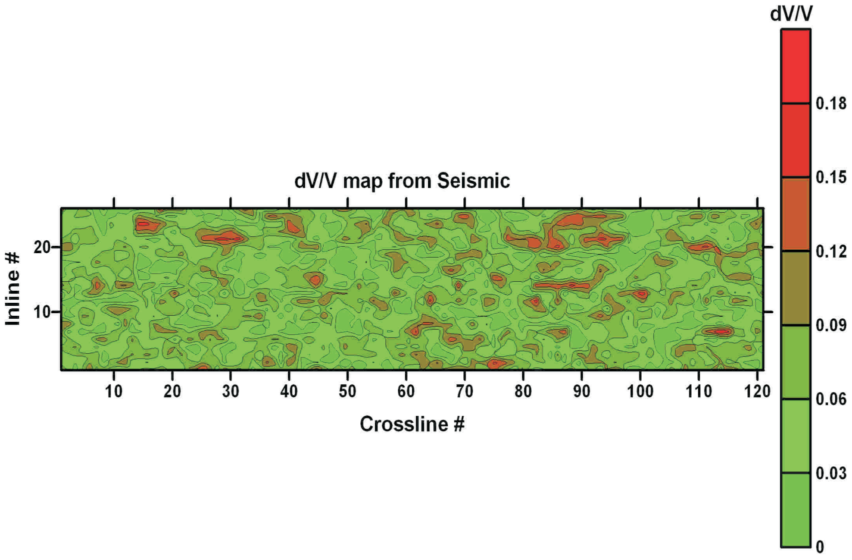

Fig. 2 Normalized velocity uncertainty estimated using equation 2 for the entire horizon from picked dt at each CMP location.

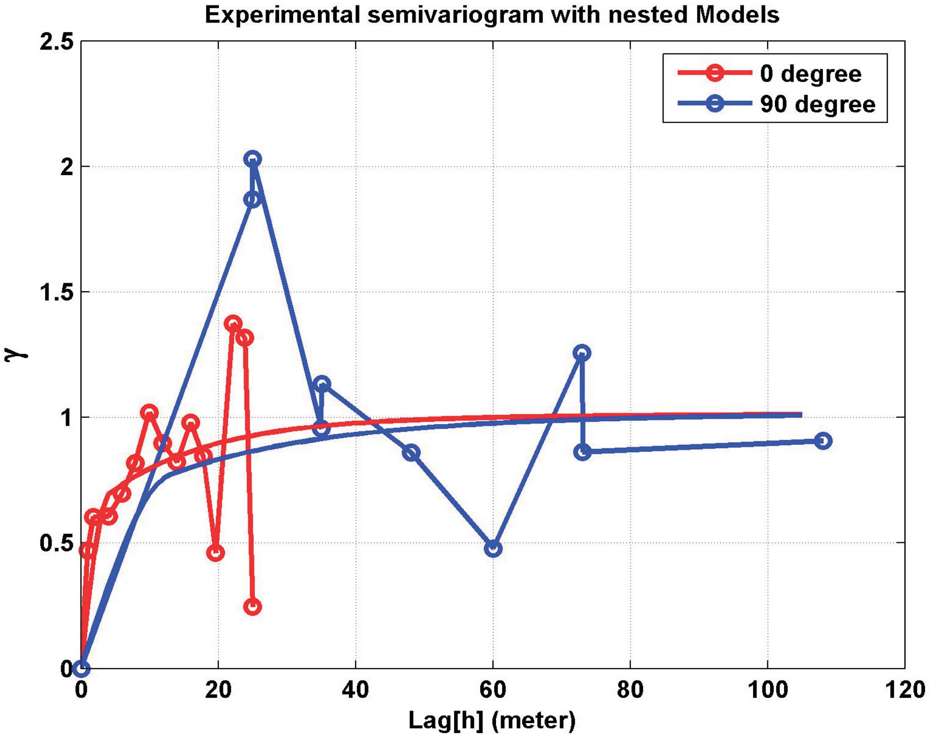

Fig. 3 Experimental semivariogram (continuous lines) for δ^h in different directions. Smooth lines are the corresponding models. These variogram models are utilized for Ordinary Kriging.

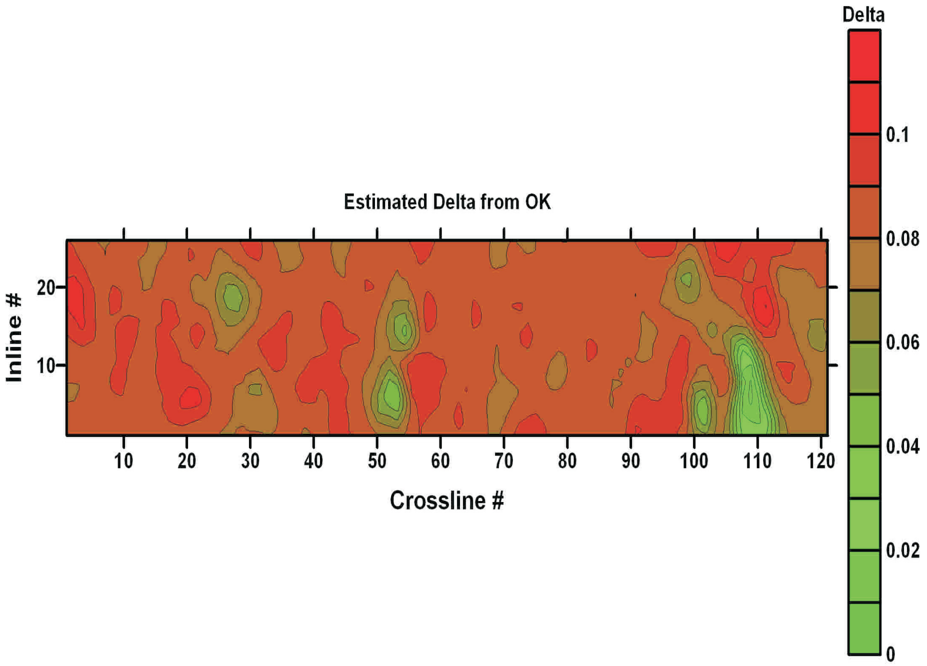

Fig. 4 OK estimated δ^h values for the entire study area. Absolute values are shown here. The range of δ^h is realistic in terms of rock physics and weak anisotropy.

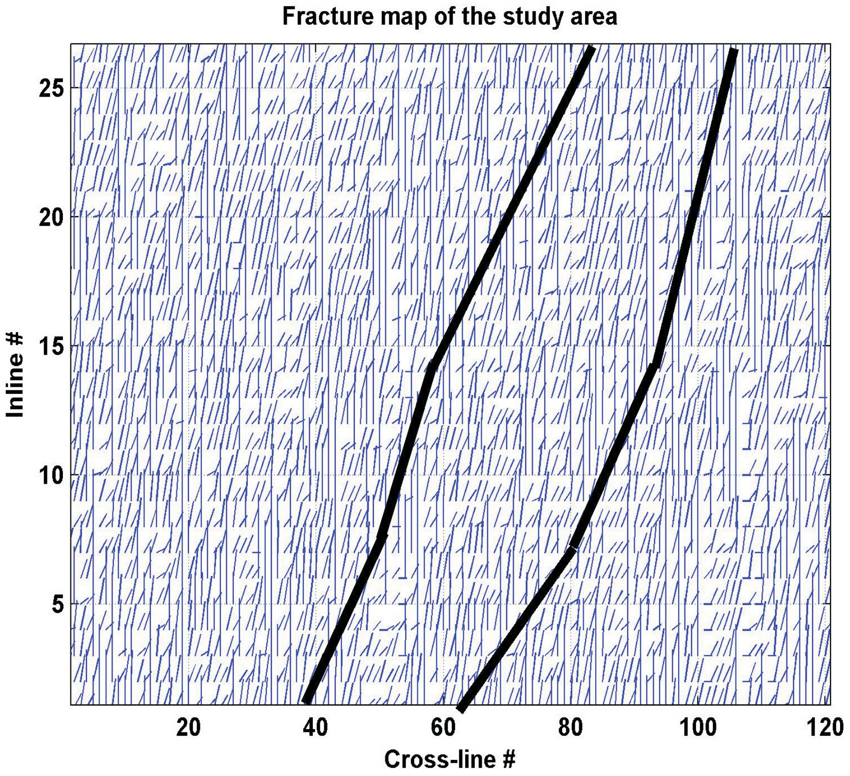

Fig. 5 From estimated δ^h values and input dv/v map (fig 2), a fracture strike map is prepared. The derived fracture map has two prominent strike directions. Major faults of the study area are also plotted in the figure (black lines).

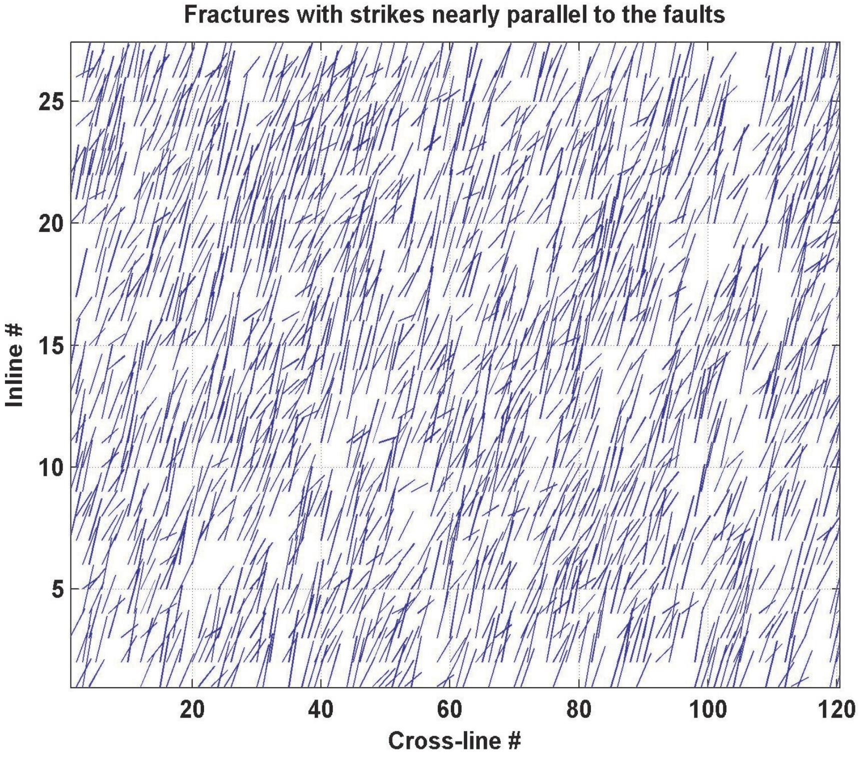

Fig. 6 Plot of the fractures nearly parallel to the major strike directions. This plot is a subset of fig 5. We are also not plotting the fracture with 0 degree strikes in this figure to emphasize the pattern of the fracture system.

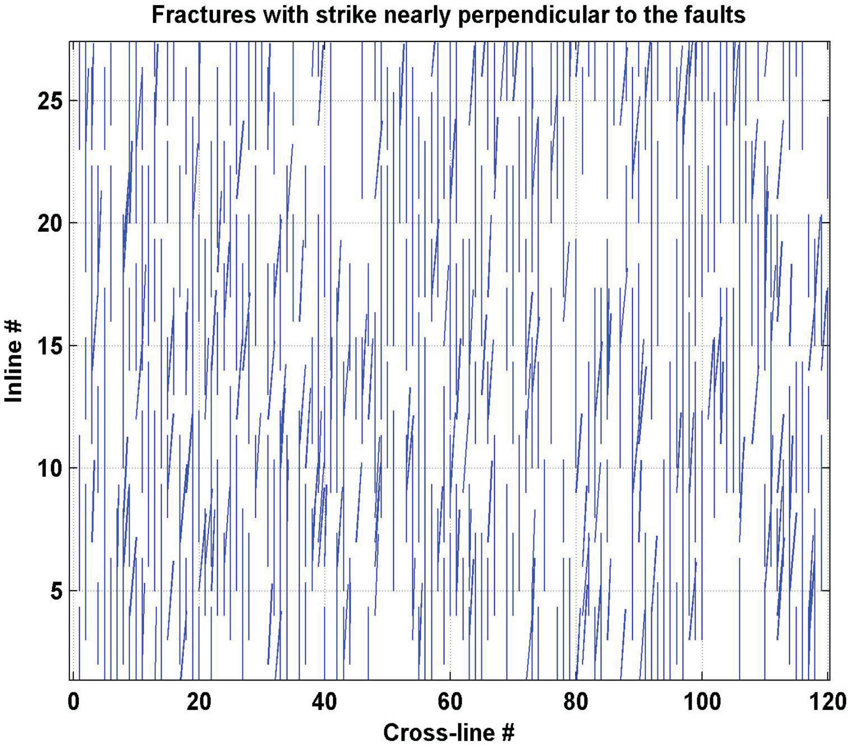

Fig. 7 Plot of the second set of fractures nearly perpendicular to the fault system. This figure is also a subset of fig 5.

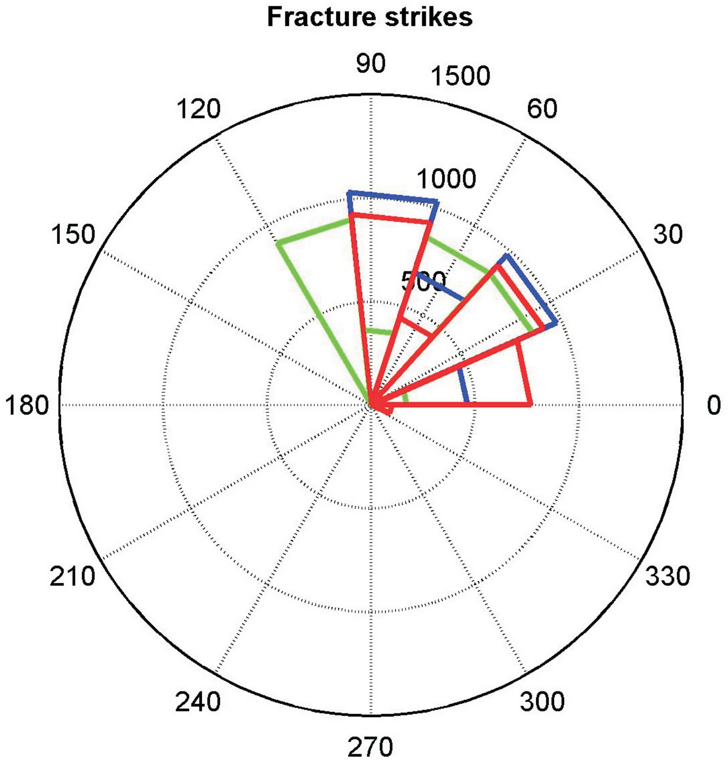

Fig. 8 Rose diagram of the estimated fractures. There are two major directions of fracture orientations. One along ~ 110 degree and another along ~30 degree. Fracture strikes are almost parallel and perpendicular to the faults.

Estimated δ^h values range between 0 to 0.1. Now from Figure 2 and Figure 4 and using equation 4, we generate a fracture direction map (90°-φ) at each CMP location. In Figure 5, we display our resulting fracture map along with two major faults present in the study area. Major fracture orientations are almost parallel and perpendicular to the strike directions of the two major faults. We separate out the two different types of fracture to illustrate this observation. In Figure 6 we plot the fractures nearly parallel to the major faults present in the study area. In Figure 7 we plot the faults nearly perpendicular to the faults. We also plot a rose diagram of the derived fracture orientation (Figure 8, red lines). The rose diagram shows two prominent fracture orientations (~40° and ~90° with inline) within this study area. Due to kriging, we have 'estimated variance' information at each CMP location. With the help of estimated variance, we measure two extreme bounds of fracture orientations. We plot those two bounds (green-upper, and red-lower) in Figure 8 as an estimate of uncertainty in our fracture mapping process.

Discussions and Conclusions

We have developed a simple method for estimating orientation of fracture strike from single azimuth data using near offset travel time residuals or velocity uncertainty in an NMO corrected gather. In general, determination of fracture pattern from 2D data (single azimuth) is highly uncertain. A VTI medium can also give rise to the same uncertainty in velocity and our processing can produce a pseudo fracture map. Another potential problem is determination of the δ^h and φ values simultaneously. Use of multiazimuth/3D data can easily overcome those problems. Several of these factors can be addressed using the geostatistical estimate if adequate well measurements are available for vertical velocity and δ^h. We use ordinary kriging to populate the entire study area with the δ^h values which also helps to determine uncertainty associated with δ^h values from the estimated variance of kriging. Previously, attempts were made to directly estimate the fracture orientation utilizing log derived information by kriging (Viruete et al, 2001). This process skips the step of determination of δ^h, and results in an extremely smooth nonrealistic fracture pattern. To avoid that, we perform kriging over δ^h , as δ^h value in nature varies smoothly (Wang et al., 2007). A realistic fracture pattern is then observed by using the derived δ^h .

The only inherent ambiguity which is difficult to solve is for fractures with 0° strike relative to the inline. In a rose diagram of the derived fractures (Figure 8) we see that not many of them are present in our study area. Those fractures can be artifacts, as an HTI medium behaves isotropically when fractures are parallel to the inline direction. Except for external evidence it is impossible to determine whether the medium is isotropic or contains fractures.

A very common trend in industry is processing seismic data using the isotropic assumption, even though the medium is anisotropic. We show here how we can use those over corrected data for estimating processing velocity uncertainty and for fracture mapping. Even though our example is based on 2D data, it can easily be extended for 3D data. Use of 3D data should make our method more robust by having fewer assumptions. When additional information is available, we can detect fractures using 2D data by our simple, easy to implement, method. Thus this kind of RMO analysis can confirm whether the processing velocity uncertainty is due to anisotropy or not.

Just like the x-t domain, in the τ-p domain, NMO velocity for HTI medium has two components: a near offset elliptical velocity and a far offset anniliptic term (Sil and Sen, 2008). The near offset NMO velocity (equation 3) for the x-t domain is the same for τ-p domain, so our approach to fracture mapping can easily be extended to τ-p domain. Due to anisotropic overburden, observation of an anisotropic signature from the target zone is a common phenomenon (which is not the case here, as the layer above the target zone does not exhibit the 'hockey stick effect'). Use of τ-p domain analysis can help us to get around that additional ambiguity.

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