Predicting the azimuth of natural fractures and in-situ horizontal stress: A case study from Sichuan Basin, China

<table>
<thead>
<tr>
<th>Journal</th>
<th>Geophysics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Manuscript ID</td>
<td>GEO-2020-0829.R5</td>
</tr>
<tr>
<td>Manuscript Type</td>
<td>Case Histories</td>
</tr>
<tr>
<td>Keywords</td>
<td>anisotropy, azimuth, case history</td>
</tr>
<tr>
<td>Manuscript Focus Area</td>
<td>Anisotropy, Case Histories</td>
</tr>
</tbody>
</table>
Predicting the azimuth of natural fractures and in-situ horizontal stress: A case study from Sichuan Basin, China

Kai Lin\textsuperscript{1,2}, Bo Zhang\textsuperscript{2}, Jianjun Zhang\textsuperscript{3}, Huijing Fang\textsuperscript{2,4}, Kefeng Xi\textsuperscript{5}, Zhi Li\textsuperscript{6}

Running Head: Predicting the azimuth of natural fractures and in-situ horizontal stress

\textsuperscript{1} Chengdu University of Technology, College of Geophysics

\textsuperscript{2} University of Alabama, Department of Geological Science

\textsuperscript{3} Bureau of Geophysical Prospecting (BGP) Inc. of CNPC, New Resource Geophysical Development Department

\textsuperscript{4} China University of Petroleum (Beijing), School of Geosciences

\textsuperscript{5} Petro China Southwest Oil & Gas Field Branch

\textsuperscript{6} Petro China Southwest Oil & Gas Field, Central Sichuan Oil and Gas Mine

\textsuperscript{1} Linkai02102@163.com, \textsuperscript{2}bzhang33@ua.edu, \textsuperscript{3}zhangjianjun1@cnpc.com.cn, \textsuperscript{4}hfang11@ua.edu, and \textsuperscript{5}xkf@petrochina.com.cn, \textsuperscript{6}342784930@qq.com

Corresponding author:

Bo Zhang

The University of Alabama, Department of Geological Science

bzhang33@ua.edu
Predicting the azimuth of natural fractures and in-situ horizontal stress: A case study from Sichuan Basin, China

ABSTRACT

The azimuth of fractures and in-situ horizontal stress are important factors in planning horizontal wells and hydraulic fracturing for unconventional resources plays. The azimuth of natural fractures can be directly obtained by analyzing image logs. The azimuth of the maximum horizontal stress $\sigma_H$ can be predicted by analyzing the induced fractures on image logs. The clustering of micro-seismic events can also be used to predict the azimuth of in-situ maximum horizontal stress. However, the azimuth of natural fractures and the in-situ maximum horizontal stress obtained from both image logs and micro-seismic events are limited to the wellbore locations. Wide azimuth seismic data provides an alternative way to predict the azimuth of natural fractures and maximum in-situ horizontal stress if the seismic attributes are properly calibrated with interpretations from well logs and microseismic data. To predict the azimuth of natural fractures and in-situ maximum horizontal stress, we focus our analysis on correlating the seismic attributes computed from pre-stack and post-stack seismic data with the interpreted azimuth obtained from image logs and microseismic data. The application indicates that the strike of the most positive principal curvature $k_1$ can be used as an indicator for the azimuth of natural fractures within our study area. The azimuthal anisotropy of the dominant frequency component if offset vector title (OVT) seismic data can be used to predict the azimuth of maximum in-situ horizontal stress within our study area that is located the southern region of the Sichuan Basin, China. The predicted azimuths provide important information for the following well planning and hydraulic fracturing.
List of Key Words: Azimuthal anisotropy, seismic attributes, fractures, in-situ horizontal stress, microseismic events

INTRODUCTION

The most important considerations in hydraulic fracturing treatment design include: the rock mineral composition, rock mechanics properties, the in-situ horizontal stress field, and the distribution of natural fractures. Fractures can be produced by a range of geological activities such as local tectonic activity, stress, shrinkage, unloading, and weathering (Gale et al., 2014). Fracture systems are very important for shale resource plays and provide migration conduits and space for the hydrocarbons. Natural fracture systems also affect the propagation of the fracturing fluids. Hydraulic fracturing improves hydrocarbon flow by creating induced fractures within the formation that connect the reservoir and wellbore. The size and orientation of hydraulically induced fractures are dictated by the formation’s in-situ stress. Thus, predicting the azimuth of natural fractures and in-situ horizontal stress are essential in shale resource plays. In this paper, we focus on predicting the azimuth of the in-situ horizontal stress field and natural fractures by integrating multiple types of data.

Seismic data is commonly used to predict the distribution of fractures and there are two main categories of fracture prediction by using seismic data. The first category involves correlating post-stack seismic geometry attributes and fractures interpreted at the wellbore location. The commonly used seismic attributes include coherence, curvature, automatic fault extraction (AFE), and fault likelihood. Verma and Scipione (2020) utilized seismic curvature and aberrancy attributes along with image logs to study lineaments and fracture zones. They
observed that fractures zones identified by anomalous curvature values influence production. Chopra and Marfurt (2019) considered coherence as a discontinuity detection attribute, which can be applied to the interpretation of faults and fractures. Curvature measures the structural deformation (strain), which can be correlated with fractures (Stearns, 2015). Strata that have been exposed to strong tectonic stresses should have high curvatures. Researchers (e.g., Chopra and Marfurt, 2010; Staples, 2011) have successfully used seismic curvature as a proxy to identify highly strained zones that are already fractured. Liang (2019) proposed a fracture likelihood attribute by analyzing the similarity of time samples along the dip and strike of seismic data.

The second category involves analyzing how seismic propagation features vary with azimuth and offset. Lynn (2020) documented the use of azimuthal anisotropy in estimating structure, lithology, porosity, pore fluids, in situ stress, and aligned porosity that allows for flows fluid (macro-fracture porosity) in the last 40 years. The analysis of pre-stack wide-azimuth seismic data is usually based on the OVT data (Lynn, 2016). Researchers have analyzed P-wave (travel time or velocity) azimuthal anisotropy (e.g., Lynn, 2018; Li et al., 2002), seismic (P-wave and S-wave) amplitude versus azimuthal anisotropy as AVAz or azimuthal AVO (e.g., Ruger, 1998; Lynn, et al., 1995, 1996, 1999), attenuation anisotropy (Chichinina et al., 2006), and frequency versus azimuthal anisotropy as FVAz or azimuth FVA (Ali and Jakobsen., 2014). Jaime et al. (2010) predicted the fractures by analyzing the azimuthal anisotropy of travel time and velocity of snail gathers. Li (2013) used the azimuth AVO gradient to predict the azimuth and distribution of fractures. Ali et al. (2009) and Sharma et al. (2018) used AVAz to inverse for the azimuth and density of fractures. Guo et al. (2016)
found that AVAz and seismic curvature have differences in their response for seismic surveys obtained pre- and post-hydraulic fracturing. Sonja et al. (2007) used attenuation anisotropy to study the development characteristics of fractures near the wellbore locations. Grimm et al. (1999) and Lynn (2004) found that frequency anisotropy can be used to predict fractures. Although researchers can analyze any features of seismic waveforms varying with offset and azimuth, analyzing the azimuthal variation of P-P AVA gradient is regarded as an industry standard for detecting vertically aligned fractures (Lynn et al., 1995, 1996, 1999; Lynn, 2020).

To obtain an accurate estimate of azimuthal anisotropy, huge efforts have been spent on the forward modeling for azimuthal anisotropy characteristics, such as velocity, travel time, amplitude, and attenuation (Q value) versus with azimuth and offset (Gray and Head, 2000; Jenner, 2002; Zhu et al., 2007; Ekanem et al., 2009).

The in-situ stress is one of the driving forces for hydrocarbon migration (Rouchet, 1981; Wang et al., 2011). At the same time, the in-situ stress field and the mechanical properties of the rock together determine the azimuth and distribution of induced fractures during hydraulic fracturing. The most reliable and direct stress field measuring techniques include core testing methods, hydraulic fracturing methods, and acoustic sound emission methods (Seto et al., 1999; Yin et al., 2018). Other techniques, such as borehole break analysis, well-logs analysis, and induced fracture analysis on image logs can provide valuable information about the in-situ stress field. Nikolaevskiy and Economides (2000) used image log data to measure the depth and width of breakouts and predicted the maximum and minimum horizontal principal stress. Liu et al. (2005) used multipolar acoustic logging to determine the azimuth of in-situ stress. Zhang et al. (1993) used formation dip logging to determine the azimuth of wellbore breakout.
and obtained the azimuth of in-situ stress. More recently, Zhang et al. (2015) combine to use the VTI rock physics model to predict in-situ stress.

Seismic data have been used to provide indirect measurements of the in-situ stress field. Lynn et al. (1995, 2014) are the pioneers who combine the P-wave reflection seismic data, VSP, borehole imaging logs to determine the in-situ stress field. Dillen (2000) deduced the relationship between reflection coefficients and stress. Tigrek et al. (2003) correlated the PP-PS wave reflection coefficient with the in-situ stress and calculated the in-situ stress with a geomechanical model. Hunt et al. (2011) established the relationship between formation curvature and in-situ stress. He (2011) derived an in-situ stress expression using curvature under the assumption of thin plate theory. Goodway et al. (2010) assumed that the horizontal strain of formation can be ignored and proposed a formula to calculate the minimum horizontal principal stress of isotropic media. Gray et al. (2012) computed the in-situ stress using seismic data in a linear elastic VTI medium. Lynn (2014) observed that unequal horizontal stresses, or vertically aligned fractures that are conduits for fluid flow can cause observable seismic azimuthal anisotropy. Ma et al. (2017, 2018) deduced in-situ stress using seismic data in the orthorhombic anisotropic medium.

In this paper, we present a case study of predicting the azimuth of natural fractures and the in-situ stress of a shale reservoir located within the Sichuan Basin, China. Firstly, we determine the azimuth of natural fractures and in-situ horizontal stress at the wellbore location using image logs. Then, we classify the microseismic ruptures according to the fracturing phases, and linear fit “the trend” of the classified microseismic ruptures. We assume that the fitted trend of microseismic events is correlated with the growth direction of hydraulic fractures.
Note that hydraulic fractures usually grow parallel to the maximum horizontal stress when pre-existing lines of weakness (paleo-fractures) are not present. If paleo-fractures are present, these lines of pre-existing weakness may serve as conduits for the fracturing fluids, such that these paleo-fractures serve as the position of subsequent microseismic ruptures. The relationship between the azimuth of the maximum horizontal stress and the azimuth of the fractures governs how open-able these paleo-fractures are, when fracturing fluid is injected. Thus, the fitted trend can be used as an indicator for the azimuth of the maximum horizontal stress. Next, we compute a set of post-stack seismic attributes and anisotropy parameters using post-stack and pre-stack seismic data, respectively. The strike of post-stack seismic attributes and azimuthal of anisotropy are correlated with the interpreted azimuth of the fractures and in-situ stress at the wellbore location. Finally, we predict the azimuth of natural fractures and in-situ stress using the seismic attributes that have the best correlation with interpretation at the well locations.

**GEOLOGICAL SETTING**

The study area (the blue rectangles in Figures 1a and 1b) is located within the southern region of the Sichuan Basin. Figures 1a shows the topographic map of the Sichuan Basin and adjacent area, respectively. Figure 1b shows the tectonic framework of the Sichuan Basin and adjacent area. Two main fault sets have developed within the study area (Zhang et al., 2011). The azimuth of maximum regional horizontal stress was along the N-S direction during the late Himalayan orogeny and NW-SE direction during the middle Himalayan Orogeny that resulted in compression and compressive-torsional fault sets with NE-striking and NW-striking. The strikes of the faults are consistent with the stress changes that happened in the entire
Sichuan Basin during the middle and late Himalayan Orogeny (Wu et al., 2015). The regional azimuth of maximum horizontal stress at the study area is along the NW-SE direction in the middle Himalayan period and along the N-S direction in the late Himalayan Orogeny, respectively (Xian et al., 2017).

Figure 2 shows a chair-display of post-stack seismic data overlaid with the trajectories of one vertical (Well A) and three horizontal wells (Well H1, H3, H5). The horizon shown in Figure 2 is the base of the Longmaxi-Wufeng marine shale formation that is the target formation within the study area (Jin, 2013). The Longmaxi formation is a black graptolite shale. The upper part of the Longmaxi formation is marl and silt limestone, while the lower part of the Longmaxi formation contains more pyrite nodules.

**Interpreting the azimuth of natural fractures and in-situ stress using image logs**

The image logs provide geologists with a picture of the downhole environment and are commonly used to analyze the reservoir properties such as heterogeneity, sedimentary conditions, and structural features such as fractures, folds, and faults (Brown et al., 2015). On image logs, the fractures demonstrate are dark in color due to their high conductivity. The fractures seen on image logs mainly include open natural fractures and drilling-induced fractures. The natural fractures are critical to the production of unconventional resource plays (Khelifa et al., 2014). The drilling-induced fractures (collapse and rupture of the sidewall rock) are closely related to the azimuth of the orientation of extensional stress, size, and rock strength. Therefore, the azimuth of the induced fractures is used to indicate the azimuth of the maximum horizontal principal stress (Titheridge, 2014). Furthermore, the azimuth of the natural fractures...
is used to determine the azimuth of fractures developed at the wellbore location. Figure 3 illustrates the interpreted results for the imaging logs at Well A. Note that natural fractures are present (indicated by the blue lines), as well as the steeply dipping induced fractures (indicated by the green arrows in Figure 3). Figure 4 shows the azimuth of interpreted natural and induced fractures within the target formation at the Well A location. The rose diagram in Figure 4a indicates that there two natural fractures sets. The strike of the dominant fracture set is approximately along the east-west azimuth. The strike of the second fracture set is along the NE-SW direction. Figure 4b shows that the strike of induced fractures is along the NW-SE direction with an average angle value of 140°. From this figure, we conclude that the azimuth of maximum in-situ horizontal stress is approximately N140W at the Well A location.

**Interpreting the azimuth of in-situ stress using micro-seismic events**

Hydraulic fractures usually propagate in the horizontal or vertical direction based on the in-situ stress directions and preexisting planes of weakness (e.g., natural fractures) within the formation. In this paper, we simply ignore the effect of preexisting planes of weakness on the fracture propagation and assume that in-situ stress dominates the propagation of hydraulic fractures. Microseismic events are thought to be an indicator of hydraulic ruptures. Thus, the “trend” of the microseismic events can be treated as the propagation direction of hydraulic fractures. In this paper, we compute the azimuth of the maximum in-situ stress by linearly fitting the “trend” of microseismic ruptures (microseismic events). Denote \((x_i, y_i)\) as the coordinates of for the \(i^{th}\) microseismic rupture and \(y = kx + b\) as the fitted linear curve, where \(k\) and \(b\) are the slope and intercept, respectively. Then, the objective is to minimize...
the square sum of error \( f = \sum_{i=1}^{n} (y_i - k \cdot x_i - b)^2 \) where \( n \) is the number of microseismic ruptures. We use least squares to compute parameters \( k \) and \( b \) as follows:

\[
k = \frac{Am - CD}{nB - c^2},
\]

\[
b = \frac{AC - DB}{c^2 - nB}.
\]

where

\[
A = \sum_{i=1}^{n} (x_i \cdot y_i)
\]
\[
B = \sum_{i=1}^{n} x_i^2
\]
\[
C = \sum_{i=1}^{n} x_i
\]
\[
D = \sum_{i=1}^{n} y_i
\]

According to equation 1, the azimuth of maximum (respected to x-axis) in-situ stress is defined as

\[
\theta = \begin{cases} 
\arctan(k) \times \frac{180}{\pi}, & k > 0 \\
180 + \arctan(k) \times \frac{180}{\pi}, & k < 0
\end{cases}
\]

The red dots and black curve in Figure 5 are the hydraulic ruptures and fitted trend of hydraulic ruptures. Finally, we obtain the azimuth of maximum in-situ stress shown in Figure 5 by using equation 4 (the direction of x-axis is defined as the azimuth of 0°),

\[
\theta = 180 + \arctan(-0.8842) \times \frac{180}{\pi} \approx 138°.
\]

Figures 6a, 7a, and 8a show the spatial positions of microseismic ruptures (the small balls with different colors) near Well H1, Well H3, and Well H5, respectively. The ruptures with the same color were produced during the same hydraulic fracturing phase. Figures 6b, 7b, and 8b show the computed azimuth of the maximum in-situ horizontal stress by linear fitting the red microseismic ruptures that are shown in Figures 6a, 7a, and 8a, respectively.
Computing the azimuth of anisotropy using wide azimuth seismic data

The OVT seismic gathers are sorted into nine azimuth sectors (10°, 30°, 50°, 70°, 90°, 110°, 130°, 150°, and 170°), as illustrated in Figure 9a. We compute the seismic gather of a specific azimuthal sector using the seismic data that falls within two narrow azimuth bands that are centered at the corresponding azimuthal sector. For example, the seismic gather at the 50° azimuth sector is computed using the seismic data that falls within two narrow azimuth bands: 40°-60° and 220°-240°. The distribution of offset and azimuth of the seismic gather shown in Figure 9b demonstrates that the seismic survey has evenly distributed offsets and azimuths within each azimuth sector. Figures 10 and 11 show the computed gathers (at well A) of the nine defined azimuthal sectors and corresponding amplitude varies with offset, respectively. The AVO phenomenon shown in Figure 11 describes the seismic reflections at the interface (the base of our target formation) between a shale and carbonate formations (Figure 12a). Figures 12b and 12c show a 2D isotropic layer-cake model and corresponding AVO feature that is computed using the Zoeppritz equation at the interface between shale and carbonate formations. The modeled P-P seismic reflection amplitude shows a similar feature with the second model (the prestack amplitude modeling section) illustrated by Lynn and Goodway (2020). Lynn and Goodway (2020) concluded that the less negative AVA gradients indicate decreases in the $V_s$ of the carbonate, due to the carbonate becoming less stiff to shear stress. Considering that our model has the same lithology combination with that of Lynn and Goodway (2020), we conjecture that the underlying carbonate at Well A becomes less stiff to shear stress. Figure 13a shows the linear fit for the seismic amplitude versus offset using a two-term AVO equation. The gradient of the fitted linear line shown in Figure 13a is further used
to compute the anisotropic ellipsoid shown in Figure 13b. Figure 11 demonstrates that the azimuth sectors of 50°, 70°, 110°, and 130° have similar reflection features (negative gradients) with that of synthetic seismic reflection coefficient shown in Figure 12c. Note that different azimuths have different AVO shown in Figure 11. Certain azimuths (e.g., azimuths of 10°, 50°, 130°) first have amplitude increasing with increasing offset for the small offset seismic data, and then have amplitude decreasing with increasing offset for the medium and far offset gathers. Other azimuths show a constant amplitude increasing (e.g., 90°) or decreasing (e.g., 70°) with increasing offset. Lynn and Goodway (2020) concluded that the aligned porosity gives rise to the azimuthal variation on the near-angle amplitudes that is also observed in Figure 11 and observed that the predicted azimuth using AVA gradients agrees with the estimated azimuth of the fractures when 6°-45° angle of incidences are used. Thus, it is critical to include far offset seismic data in analyzing fractures (or in-situ stress) by using the AVO gradient.

In theory, any seismic attributes varying with offset and azimuth can be used to estimate the azimuth of natural fractures and in-situ stress. To select the best seismic parameter that can be used to predict the azimuth of natural fractures and in-situ stress, we study six seismic parameters versus offset and azimuth. Those six parameters are seismic root mean square amplitude, seismic maximum amplitude, seismic amplitude, dominate frequency, instantaneous amplitude, and instantaneous frequency. Figure 14a-f shows the fitted anisotropic ellipsoids for the seismic gather shown in Figure 10 by using the seismic parameters of seismic root mean square (RMS) amplitude, seismic maximum amplitude, seismic amplitude, seismic dominant frequency, seismic instantaneous amplitude, and seismic instantaneous frequency, respectively. Figure 14a-d demonstrates that the two principal
azimuths are approximately 140° and 10°. So, the azimuth 140° agrees with the azimuth (N140E) of induced fractures shown in Figure 4b and supports the point of view that the strike of the induced natural fractures can be used as an indicator for the azimuth of maximum in-situ stress. Figure 15 shows the computed gradient of seismic amplitude at the base of the target formation for the nine azimuthal sectors. Figure 16 shows the azimuth of the long axis of the fitted anisotropic ellipsoid by using the gradient shown in Figure 15. Figure 17a-f shows the azimuth of the long axis of fitted anisotropic ellipsoid for the seismic parameters of seismic RMS amplitude, seismic maximum amplitude, seismic amplitude, seismic dominant frequency, seismic instantaneous amplitude, and instantaneous frequency, respectively.

Seismic geometry attributes

In this paper, we also study the correlation between the azimuth/strike of post-stack seismic attributes and azimuth of natural fractures (and maximum horizontal stress). We compute the post-stack seismic attributes using full-stack seismic data. The main post-stack seismic geometry attributes that have azimuth information include the strike of the most positive principal curvature ($k_1$), the strike of the most negative principal curvature ($k_2$), the azimuth of reflector convergence, the strike of the most positive, the strike of the most negative, and the azimuth of total aberrancy. The definition of these attributes and corresponding strike/azimuth can be found in the paper published by Marfurt (2006). Figure 18 a-f shows the computed azimuth/strike for the six post-stack seismic geometry attributes nearby the wellbore trajectories, respectively.
Mapping the azimuth of fracture and in-situ horizontal stress by integrating seismic, well and microseismic data

In this paper, the azimuth interpreted using image logs and microseismic data function as the benchmark of the azimuth of fractures and in-situ horizontal stress. To choose the best seismic attribute that can be used to predict the azimuth of fractures and in-situ horizontal stress, we simply correct the benchmark azimuth with the azimuth computed from both pre-stack and post-stack seismic attributes.

Correlating the azimuth/strike of seismic attributes with azimuth of natural fractures

Table 1 summarizes the azimuth/strike of seismic attributes and interpreted azimuth of natural fractures using the image log at the Well A location. Table 1 illustrates that the strike of most positive principal curvature has the best correlation with the strike of the dominant fracture set. Unfortunately, neither the azimuth of the long axis of the fitted anisotropic ellipsoids nor the strike of other post-stack seismic attributes have a good correlation with the azimuth of interpreted natural fractures. Table 1 demonstrates that the strike of the most positive principal curvature can be used an indicator for the azimuth of natural fractures within the target formation.

Correlating the azimuth/strike of seismic attributes with the azimuth of the in-situ stress

Table 2 summarizes the azimuth/strike of seismic attributes and interpreted azimuth of in-situ maximum horizontal stress using image logs at the Well A location. Table 2 clearly illustrates that the azimuth of maximum in-situ horizontal stress has the best correlation with the predicted azimuth using seismic RMS amplitude. However, note that the predicted azimuths by using other attributes (e.g., maximum amplitude, AVAz, FVAz) also have very
good correlation with the interpreted azimuth. Thus, it is very hard to judge which attribute is
the best attribute to predict the azimuth of the maximum in-situ horizontal stress within our
target formation. To further verify the seismic attribute that can be used to indicate the azimuth
of maximum in-situ horizontal stress, we correlate the azimuth of maximum in-situ horizontal
stress, which is computed using microseismic data, with the azimuth/strike of seismic attributes.

In this paper, we estimate 68 values of the azimuth of maximum in-situ horizontal stress
using the locations of microseismic ruptures and the value of azimuth varies from 53° to 163°,
as shown in the blue histogram in Figure 19. The red histograms in Figure 19a-f stand for the
distribute of azimuth at the rupture locations that that were computed using the seismic
parameters of seismic RMS amplitude, seismic maximum amplitude, seismic amplitude,
seismic dominant frequency, seismic instantaneous amplitude, and instantaneous frequency,
respectively. Figure 19 demonstrate that the distribution of azimuth values, which is computed
using the dominant frequency versus azimuth and offset, has the best correlation with the
distribution of azimuth values of the interpreted maximum in-situ horizontal stress. The red
histograms in Figure 20a-f show distribution of the strike/azimuth of post-stack seismic
attributes of (a) the most positive principal curvature \( k_1 \), (b) the most negative principal
curvature \( k_2 \), (c) the reflector convergence curvature, (d) the most positive curvature, (e) the
most negative curvature, and (f) total aberrancy curvature, respectively. The blue histogram in
Figure 20 is the same interpreted azimuth as shown in Figure 19. Figure 20 demonstrates that
the distribution of azimuth/strike values, which are computed using post-stack seismic
attributes, have no correlation with the distribution of azimuth values of interpreted maximum
in-situ horizontal stress.
To further evaluate the predicted azimuth, we crossplot interpreted azimuth with average predicted azimuth. We compute the average predicted azimuth by using the estimated azimuth at the rupture locations that are used to interpretate the azimuth of in-situ stress for each “group” of ruptures. Figure 21a-f shows the crossplot of interpreted azimuth and average predicted azimuth computed using the seismic parameters of seismic RMS amplitude, seismic maximum amplitude, seismic amplitude, seismic dominant frequency, seismic instantaneous amplitude, and instantaneous frequency, respectively. Figure 22a-f shows the crossplot of interpreted azimuth and average predicted azimuth computed using (a) the most positive principal curvature $k_1$, (b) the most negative principal curvature $k_2$, (c) reflector convergence, (d) the most positive curvature, (e) the most negative curvature, and (f) total aberrancy, respectively. The horizontal and vertical axes in Figures 21 and 22 are the interpreted azimuth by fitting the trend of microseismic ruptures and average predicted azimuth, respectively. Figures 21 and 22 together demonstrate that seismic dominant frequency versus azimuth and offset is the best seismic attribute that can be used to predict the azimuth of in-situ stress in our study area.

Table 1, Table 2, Figures 19-22 together illustrate that the azimuth of the long axis of fitted anisotropic ellipsoid, which is computed using the seismic dominant frequency varying with azimuth and offset, is the best attribute that can be used to predict the azimuth of maximum horizontal stress in our study area. The predicted azimuth of maximum in-situ horizontal stress mainly fall within the range between $90^\circ$ and $160^\circ$ (Figure 23), which is consistent with the regional structural interpretation within the study area (Xian et al., 2017).
CONCLUSIONS

In this paper, we conducted a comprehensive correlation between the estimated azimuth computed from seismic parameters with the interpreted benchmark azimuth of natural fractures and in-situ maximum horizontal stress. The application demonstrates that the azimuth/strike of post-stack geometry seismic attributes and the azimuth of fitted anisotropic ellipsoids that is computed from pre-stack seismic gathers can be used to predict the azimuth of fractures and in-situ horizontal stress. The application shows that the strike of most positive principal curvature can be used to characterize the natural fractures azimuth. The predicted azimuth of the fractures has a very good correlation with the interpretation at the wellbore locations. The seismic parameters FVAz can be used to characterize the azimuth of in-site horizontal stress. We must point out that the chosen best seismic attribute, which is used for predicting the azimuth of natural features and maximum in-situ horizontal stress in our paper, may not work for other seismic surveys. However, the workflow illustrated in this paper should work in the azimuth prediction of natural fractures and in-situ maximum horizontal stress for the shale resource plays of other seismic surveys.

DATA AND MATERIALS AVAILABILITY

Data associated with this research are confidential and we cannot release them for public.
REFERENCES


Chopra, S., and K. Marfurt, 2019, Multispectral, multiazimuth, and multioffset coherence attribute applications: Interpretation, 7(2), 21-32.


Liang, Z., 2019, Poststack seismic prediction techniques for fractures of different scales: Geophysical Prospecting for Petroleum, 58(5), 766-772.


Lynn, H., 2014, Azimuthal anisotropy: Distinguishing between unequal horizontal stress and vertical aligned macro-fractures, as demonstrated in thirty years of field data analysis: 87th International Annual Meeting, SEG, Expanded Abstracts, 473-479.


Lynn, H., 2020, Seismic field data displaying azimuthal anisotropy, 1986-2020: Interpretation, 8(4), SP135-SP156.


Seto, M., D. Nag, and V. Vutukuri, 1999, In-situ rock stress measurement from rock cores using the acoustic emission method and deformation rate analysis: Geotechnical & Geological Engineering, 17, 241–266.


Zhang, H., G. Qu, and C. Yan, 1993, New usage of diameter log in oilfield development: Oil & Gas Geology, 14(2), 118-125.


LIST OF FIGURE CAPTIONS

**Figure 1.** Tectonic framework of China and simplified tectonic map of the Sichuan Basin and adjacent area. (a) The digital elevation map showing the topography and basin-mountain systems in the Sichuan basin and adjacent area (modified from Liu et al., 2012). (b) The tectonic framework of Sichuan Basin and adjacent area (modified from Xu et al., 2020). The blue rectangle shows the study area.

**Figure 2.** The chair display of post-stack seismic data overlaid with the base of Longmaxi-Wufeng shale formation within the Sichuan Basin, China. The vertical well (Well A) has image logs. The horizontal wells (H1, H3, H5) have microseismic data.

**Figure 3.** The interpreted (a-b) natural, (c-d) induced, and (e-f) steep dipping open fractures. The green arrows in (c) and (d) indicate representative induced fractures.

**Figure 4.** Rose diagram of (a) interpreted natural and (b) induced fractures using the image logs at Well A location. The strike of induced natural fractures can be used as indicator for the azimuth of maximum in-situ horizontal stress.

**Figure 5.** Cartoon shown the linear fitting the microseismic fracturing ruptures of one fracturing phase at Well H1 location. The slope of the fitted linear line is used to compute the azimuth of the local in-situ stress.

**Figure 6.** Computing the azimuth of in-situ maximum horizontal stress using the fracturing ruptures of one fracturing phase near Well H1 location. (a) The wellbore trajectories and microseismic fracturing ruptures (the dots). The dots with same color stands for the fracturing ruptures that were generated in the same fracturing phase. (b) The zoomed in display of red
rupture points nearby Well H1. We compute direction of the in-situ maximum stress by linear fitting the locations of the rock ruptures.

**Figure 7.** Computing the azimuth of in-situ maximum horizontal stress using the fracturing ruptures of one fracturing phase nearby Well H3 location. (a) The wellbore trajectories and microseismic fracturing ruptures (the dots). The dots with same color stands for the fracturing ruptures that were generated in the same fracturing phase. (b) The zoomed in display of red rupture points nearby Well H3. We compute direction of the in-situ maximum stress by linear fitting the locations of the rock ruptures.

**Figure 8.** Computing the azimuth of in-situ maximum horizontal stress using the fracturing ruptures of one fracturing phase nearby Well H5 location. (a) The wellbore trajectories and microseismic fracturing ruptures (the dots). The dots with same color stands for the fracturing ruptures that were generated in the same fracturing phase. (b) The zoomed in display of red rupture points nearby Well H5. We compute direction of the in-situ maximum stress by linear fitting the locations of the rock ruptures.

**Figure 9.** The parameters of the studied wide azimuth seismic survey. (a) The azimuth diagram of the study area. We defined nine azimuths in our study area. (b) The azimuth-offset distribution of offset vector title (OVT) seismic data.

**Figure 10.** The pre-stack gathers for the nine azimuths at well A. The strong positive seismic reflection nearby 1700 ms indicates the base of Longmaxi-Wufeng formation (the interface between shale and carbonate formations). The yellow lines indicate the time index of seismic amplitude peak at different offsets and azimuths. The extracted amplitude is used for the
following analysis of amplitude varies with offset and azimuth.

**Figure 11.** The amplitude variation with offset for the base of Longmaxi-Wufeng formation at the azimuth bin of (a)10°, (b)30°, (c)50°, (d)70°, (e)90°, (f)110°, (g)130°, (h)150°, and (i)170°, respectively.

**Figure 12.** The forward modeling for the amplitude variation with offset at the base of Longmaxi-Wufeng formation. (a) The P-wave, S-wave, and density logs of Well A. (b) The two-layer cake model and corresponding elastic parameters. (c) The amplitude variation with offset at the interface between the shale and carbonate formations.

**Figure 13.** Diagram showing the procedure of computing the anisotropic ellipsoid. (a) Cartoon showing the linear fitting for the seismic amplitude vary with offset. The gradient of the fitted linear line is further used to compute the anisotropic ellipsoid shown in (b).

**Figure 14.** The fitted anisotropic ellipsoids at the Well A location for the seismic parameters of (a) seismic root mean square (RMS) amplitude, (b) seismic maximum amplitude, (c) seismic amplitude, (d) seismic dominant frequency, (e) seismic instantaneous amplitude, and (f) seismic instantaneous frequency.

**Figure 15.** Computed gradient of seismic amplitude using pre-stack seismic gathers at the azimuth of (a)10°, (b)30°, (c)50°, (d)70°, (e)90°, (f)110°, (g)130°, (h)150°, and (i)170°, respectively.

**Figure 16.** The azimuth of the long axis of fitted anisotropic ellipsoid at the base of target formation that is computed using the gradient shown in Figure 15.

**Figure 17.** The azimuth of the long axis of fitted anisotropic ellipsoid for the seismic
parameters of (a) seismic RMS amplitude, (b) seismic maximum amplitude, (c) seismic
amplitude, (d) seismic dominant frequency, (e) seismic instantaneous amplitude, and (f)
instantaneous frequency, respectively.

**Figure 18.** The azimuth/strike of (a) the most positive principal curvature \( k_1 \), (b) the most
negative principal curvature \( k_2 \), (c) reflector convergence, (d) the most positive curvature, (e)
the most negative curvature, and (f) total aberrancy. We compute the post-stack seismic
attributes using full-stack post-stack seismic traces.

**Figure 19.** The histogram for the azimuth of (blue bars) maximum in-situ horizontal stress and
azimuth of long axis of fitted anisotropic ellipsoid (red bars) that is computed using seismic
parameters of (a) seismic RMS amplitude, (b) seismic maximum amplitude, (c) seismic
amplitude, (d) seismic dominant frequency, (e) seismic instantaneous amplitude, and (f)
seismic instantaneous frequency varying with azimuth at the locations of microseismic ruptures.

**Figure 20.** The histogram for the azimuth of (blue bars) maximum in-situ horizontal stress and
the azimuth/strike (red bars) of (a) the most positive principal curvature \( k_1 \), (b) the most
negative principal curvature \( k_2 \), (c) reflector convergence, (d) the most positive curvature, (e)
the most negative curvature, and (f) total aberrancy.

**Figure 21.** Crossplot of interpreted azimuth and predicted using (a) seismic RMS amplitude,
(b) seismic maximum amplitude, (c) seismic amplitude, (d) seismic dominant frequency, (e)
seismic instantaneous amplitude, and (f) seismic instantaneous frequency varying with azimuth
at the locations of microseismic ruptures.

**Figure 22.** Crossplot of interpreted azimuth and predicted using (a) the most positive principal
curvature \( k_1 \), (b) the most negative principal curvature \( k_2 \), (c) reflector convergence, (d) the most positive curvature, (e) the most negative curvature, and (f) total aberrancy.

**Figure 23.** The histogram of long axis of fitted anisotropic ellipsoid computed using seismic dominant frequency for the target formation.

**LIST OF TABLES**

**Table 1.** Correlating the computed azimuth/strike of seismic attributes with the interpreted azimuth of natural fractures on image log at the Well A location.

**Table 2.** Correlating the computed azimuth/strike of seismic attributes with the azimuth of maximum in-situ stress using image log at the Well A location.
Figure 1a. Tectonic framework of China and simplified tectonic map of the Sichuan Basin and adjacent area. (a) The digital elevation map showing the topography and basin-mountain systems in the Sichuan basin and adjacent area (modified from Liu et al., 2012). (b) The tectonic framework of Sichuan Basin and adjacent area (modified from Xu et al., 2020). The blue rectangle shows the study area.

279x215mm (300 x 300 DPI)
Figure 1. Tectonic framework of China and simplified tectonic map of the Sichuan Basin and adjacent area.
(a) The digital elevation map showing the topography and basin-mountain systems in the Sichuan basin and adjacent area (modified from Liu et al., 2012). (b) The tectonic framework of Sichuan Basin and adjacent area (modified from Xu et al., 2020). The blue rectangle shows the study area.

215x279mm (300 x 300 DPI)
Figure 2. The chair display of post-stack seismic data overlaid with the base of Longmaxi-Wufeng shale formation within the Sichuan Basin, China. The vertical well (Well A) has image logs. The horizontal wells (H1, H3, H5) have microseismic data.

279x215mm (300 x 300 DPI)
Figure 3. The interpreted (a-b) natural, (c-d) induced, and (e-f) steep dipping open fractures. The green arrows in (c) and (d) indicate representative induced fractures.

279x215mm (300 x 300 DPI)
Figure 4. Rose diagram of (a) interpreted natural and (b) induced fractures using the image logs at Well A location. The strike of induced natural fractures can be used as indicator for the azimuth of maximum in-situ horizontal stress.

279x215mm (300 x 300 DPI)
Figure 5. Cartoon shown the linear fitting the microseismic fracturing ruptures of one fracturing phase at Well H1 location. The slope of the fitted linear line is used to compute the azimuth of the local in-situ stress.
Figure 6. Computing the azimuth of in-situ maximum horizontal stress using the fracturing ruptures of one fracturing phase near Well H1 location. (a) The wellbore trajectories and microseismic fracturing ruptures (the dots). The dots with same color stands for the fracturing ruptures that were generated in the same fracturing phase. (b) The zoomed in display of red rupture points nearby Well H1. We compute direction of the in-situ maximum stress by linear fitting the locations of the rock ruptures.
Figure 7. Computing the azimuth of in-situ maximum horizontal stress using the fracturing ruptures of one fracturing phase nearby Well H3 location. (a) The wellbore trajectories and microseismic fracturing ruptures (the dots). The dots with same color stands for the fracturing ruptures that were generated in the same fracturing phase. (b) The zoomed in display of red rupture points nearby Well H3. We compute direction of the in-situ maximum stress by linear fitting the locations of the rock ruptures.
Figure 8. Computing the azimuth of in-situ maximum horizontal stress using the fracturing ruptures of one fracturing phase nearby Well H5 location. (a) The wellbore trajectories and microseismic fracturing ruptures (the dots). The dots with same color stands for the fracturing ruptures that were generated in the same fracturing phase. (b) The zoomed in display of red rupture points nearby Well H5. We compute direction of the in-situ maximum stress by linear fitting the locations of the rock ruptures.

279x215mm (300 x 300 DPI)
Figure 9. The parameters of the studied wide azimuth seismic survey. (a) The azimuth diagram of the study area. We defined nine azimuths in our study area. (b) The azimuth-offset distribution of offset vector title (OVT) seismic data.
Figure 10. The pre-stack gathers for the nine azimuths at well A. The strong positive seismic reflection nearby 1700 ms indicates the base of Longmaxi-Wufeng formation (the interface between shale and carbonate formations). The yellow lines indicate the time index of seismic amplitude peak at different offsets and azimuths. The extracted amplitude is used for the following analysis of amplitude varies with offset and azimuth.
Figure 11. The amplitude variation with offset for the base of Longmaxi-Wufeng formation at the azimuth bin of (a) 10°, (b) 30°, (c) 50°, (d) 70°, (e) 90°, (f) 110°, (g) 130°, (h) 150°, and (i) 170°, respectively.

Figure 11

279x215mm (300 x 300 DPI)
Figure 12a. The forward modeling for the amplitude variation with offset at the base of Longmaxi-Wufeng formation. (a) The P-wave, S-wave, and density logs of Well A. (b) The two-layer cake model and corresponding elastic parameters. (c) The amplitude variation with offset at the interface between the shale and carbonate formations.

279x215mm (300 x 300 DPI)
Figure 12b. The forward modeling for the amplitude variation with offset at the base of Longmaxi-Wufeng formation. (a) The P-wave, S-wave, and density logs of Well A. (b) The two-layer cake model and corresponding elastic parameters. (c) The amplitude variation with offset at the interface between the shale and carbonate formations.

279x215mm (300 x 300 DPI)
Figure 13. Diagram showing the procedure of computing the anisotropic ellipsoid. (a) Cartoon showing the linear fitting for the seismic amplitude vary with offset. The gradient of the fitted linear line is further used to compute the anisotropic ellipsoid shown in (b).
Figure 13. Diagram showing the procedure of computing the anisotropic ellipsoid. (a) Cartoon showing the linear fitting for the seismic amplitude vary with offset. The gradient of the fitted linear line is further used to compute the anisotropic ellipsoid shown in (b).

Figure 13b
Figure 14. The fitted anisotropic ellipsoids at the Well A location for the seismic parameters of (a) seismic root mean square (RMS) amplitude, (b) seismic maximum amplitude, (c) seismic amplitude, (d) seismic dominant frequency, (e) seismic instantaneous amplitude, and (f) seismic instantaneous frequency.
Figure 15. Computed gradient of seismic amplitude using pre-stack seismic gathers at the azimuth of (a) 10°, (b) 30°, (c) 50°, (d) 70°, (e) 90°, (f) 110°, (g) 130°, (h) 150°, and (i) 170°, respectively.

279x215mm (300 x 300 DPI)
Figure 15. Computed gradient of seismic amplitude using pre-stack seismic gathers at the azimuth of (a) 10°, (b) 30°, (c) 50°, (d) 70°, (e) 90°, (f) 110°, (g) 130°, (h) 150°, and (i) 170°, respectively.
Figure 15. Computed gradient of seismic amplitude using pre-stack seismic gathers at the azimuth of (a) 10°, (b) 30°, (c) 50°, (d) 70°, (e) 90°, (f) 110°, (g) 130°, (h) 150°, and (i) 170°, respectively.

Figure 15c

Figure 15. Computed gradient of seismic amplitude using pre-stack seismic gathers at the azimuth of (a) 10°, (b) 30°, (c) 50°, (d) 70°, (e) 90°, (f) 110°, (g) 130°, (h) 150°, and (i) 170°, respectively.
Figure 15. Computed gradient of seismic amplitude using pre-stack seismic gathers at the azimuth of (a) 10°, (b) 30°, (c) 50°, (d) 70°, (e) 90°, (f) 110°, (g) 130°, (h) 150°, and (i) 170°, respectively.
Figure 15. Computed gradient of seismic amplitude using pre-stack seismic gathers at the azimuth of (a)10°, (b)30°, (c)50°, (d)70°, (e)90°, (f)110°, (g)130°, (h)150°, and (i)170°, respectively.
Figure 15. Computed gradient of seismic amplitude using pre-stack seismic gathers at the azimuth of (a) 10°, (b) 30°, (c) 50°, (d) 70°, (e) 90°, (f) 110°, (g) 130°, (h) 150°, and (i) 170°, respectively.
Figure 15. Computed gradient of seismic amplitude using pre-stack seismic gathers at the azimuth of (a) 10°, (b) 30°, (c) 50°, (d) 70°, (e) 90°, (f) 110°, (g) 130°, (h) 150°, and (i) 170°, respectively.
Figure 15. Computed gradient of seismic amplitude using pre-stack seismic gathers at the azimuth of (a) 10°, (b) 30°, (c) 50°, (d) 70°, (e) 90°, (f) 110°, (g) 130°, (h) 150°, and (i) 170°, respectively.

Figure 15h

Figure 15. Computed gradient of seismic amplitude using pre-stack seismic gathers at the azimuth of (a) 10°, (b) 30°, (c) 50°, (d) 70°, (e) 90°, (f) 110°, (g) 130°, (h) 150°, and (i) 170°, respectively.
Figure 15. Computed gradient of seismic amplitude using pre-stack seismic gathers at the azimuth of (a) 10°, (b) 30°, (c) 50°, (d) 70°, (e) 90°, (f) 110°, (g) 130°, (h) 150°, and (i) 170°, respectively.
Figure 16. The azimuth of the long axis of fitted anisotropic ellipsoid at the base of target formation that is computed using the gradient shown in Figure 15.
Figure 17. The azimuth of the long axis of fitted anisotropic ellipsoid for the seismic parameters of (a) seismic RMS amplitude, (b) seismic maximum amplitude, (c) seismic amplitude, (d) seismic dominant frequency, (e) seismic instantaneous amplitude, and (f) instantaneous frequency, respectively.
Figure 17. The azimuth of the long axis of fitted anisotropic ellipsoid for the seismic parameters of (a) seismic RMS amplitude, (b) seismic maximum amplitude, (c) seismic amplitude, (d) seismic dominant frequency, (e) seismic instantaneous amplitude, and (f) instantaneous frequency, respectively.

279x215mm (300 x 300 DPI)
Figure 17e

Figure 17. The azimuth of the long axis of fitted anisotropic ellipsoid for the seismic parameters of (a) seismic RMS amplitude, (b) seismic maximum amplitude, (c) seismic amplitude, (d) seismic dominant frequency, (e) seismic instantaneous amplitude, and (f) instantaneous frequency, respectively.

279x215mm (300 x 300 DPI)
Figure 17. The azimuth of the long axis of fitted anisotropic ellipsoid for the seismic parameters of (a) seismic RMS amplitude, (b) seismic maximum amplitude, (c) seismic amplitude, (d) seismic dominant frequency, (e) seismic instantaneous amplitude, and (f) instantaneous frequency, respectively.

279x215mm (300 x 300 DPI)
Figure 17. The azimuth of the long axis of fitted anisotropic ellipsoid for the seismic parameters of (a) seismic RMS amplitude, (b) seismic maximum amplitude, (c) seismic amplitude, (d) seismic dominant frequency, (e) seismic instantaneous amplitude, and (f) instantaneous frequency, respectively.
Figure 17. The azimuth of the long axis of fitted anisotropic ellipsoid for the seismic parameters of (a) seismic RMS amplitude, (b) seismic maximum amplitude, (c) seismic amplitude, (d) seismic dominant frequency, (e) seismic instantaneous amplitude, and (f) instantaneous frequency, respectively.

279x215mm (300 x 300 DPI)
Figure 18. The azimuth/strike of (a) the most positive principal curvature $k_1$, (b) the most negative principal curvature $k_2$, (c) reflector convergence, (d) the most positive curvature, (e) the most negative curvature, and (f) total aberrancy. We compute the post-stack seismic attributes using full-stack post-stack seismic traces.

279x215mm (300 x 300 DPI)
Figure 18. The azimuth/strike of (a) the most positive principal curvature $k_1$, (b) the most negative principal curvature $k_2$, (c) reflector convergence, (d) the most positive curvature, (e) the most negative curvature, and (f) total aberrancy. We compute the post-stack seismic attributes using full-stack post-stack seismic traces.
Figure 18. The azimuth/strike of (a) the most positive principal curvature $k_1$, (b) the most negative principal curvature $k_2$, (c) reflector convergence, (d) the most positive curvature, (e) the most negative curvature, and (f) total aberrancy. We compute the post-stack seismic attributes using full-stack post-stack seismic traces.

279x215mm (300 x 300 DPI)
Figure 18. The azimuth/strike of (a) the most positive principal curvature $k_1$, (b) the most negative principal curvature $k_2$, (c) reflector convergence, (d) the most positive curvature, (e) the most negative curvature, and (f) total aberrancy. We compute the post-stack seismic attributes using full-stack post-stack seismic traces.
Figure 18. The azimuth/strike of (a) the most positive principal curvature $k_1$, (b) the most negative principal curvature $k_2$, (c) reflector convergence, (d) the most positive curvature, (e) the most negative curvature, and (f) total aberrancy. We compute the post-stack seismic attributes using full-stack post-stack seismic traces.
Figure 18. The azimuth/strike of (a) the most positive principal curvature k1, (b) the most negative principal curvature k2, (c) reflector convergence, (d) the most positive curvature, (e) the most negative curvature, and (f) total aberrancy. We compute the post-stack seismic attributes using full-stack post-stack seismic traces.
Figure 19. The histogram for the azimuth of (blue bars) maximum in-situ horizontal stress and azimuth of long axis of fitted anisotropic ellipsoid (red bars) that is computed using seismic parameters of (a) seismic RMS amplitude, (b) seismic maximum amplitude, (c) seismic amplitude, (d) seismic dominant frequency, (e) seismic instantaneous amplitude, and (f) seismic instantaneous frequency varying with azimuth at the locations of microseismic ruptures.

254x190mm (300 x 300 DPI)
Figure 19. The histogram for the azimuth of (blue bars) maximum in-situ horizontal stress and azimuth of long axis of fitted anisotropic ellipsoid (red bars) that is computed using seismic parameters of (a) seismic RMS amplitude, (b) seismic maximum amplitude, (c) seismic amplitude, (d) seismic dominant frequency, (e) seismic instantaneous amplitude, and (f) seismic instantaneous frequency varying with azimuth at the locations of microseismic ruptures.
Figure 19c

Figure 19. The histogram for the azimuth of (blue bars) maximum in-situ horizontal stress and azimuth of long axis of fitted anisotropic ellipsoid (red bars) that is computed using seismic parameters of (a) seismic RMS amplitude, (b) seismic maximum amplitude, (c) seismic amplitude, (d) seismic dominant frequency, (e) seismic instantaneous amplitude, and (f) seismic instantaneous frequency varying with azimuth at the locations of microseismic ruptures.

254x190mm (300 x 300 DPI)
Figure 19. The histogram for the azimuth of (blue bars) maximum in-situ horizontal stress and azimuth of long axis of fitted anisotropic ellipsoid (red bars) that is computed using seismic parameters of (a) seismic RMS amplitude, (b) seismic maximum amplitude, (c) seismic amplitude, (d) seismic dominant frequency, (e) seismic instantaneous amplitude, and (f) seismic instantaneous frequency varying with azimuth at the locations of microseismic ruptures.
Figure 19. The histogram for the azimuth of (blue bars) maximum in-situ horizontal stress and azimuth of long axis of fitted anisotropic ellipsoid (red bars) that is computed using seismic parameters of (a) seismic RMS amplitude, (b) seismic maximum amplitude, (c) seismic amplitude, (d) seismic dominant frequency, (e) seismic instantaneous amplitude, and (f) seismic instantaneous frequency varying with azimuth at the locations of microseismic ruptures.

254x190mm (300 x 300 DPI)
Figure 19. The histogram for the azimuth of (blue bars) maximum in-situ horizontal stress and azimuth of long axis of fitted anisotropic ellipsoid (red bars) that is computed using seismic parameters of (a) seismic RMS amplitude, (b) seismic maximum amplitude, (c) seismic amplitude, (d) seismic dominant frequency, (e) seismic instantaneous amplitude, and (f) seismic instantaneous frequency varying with azimuth at the locations of microseismic ruptures.
Figure 20. The histogram for the azimuth of (blue bars) maximum in-situ horizontal stress and the azimuth/strike (red bars) of (a) the most positive principal curvature $k_1$, (b) the most negative principal curvature $k_2$, (c) reflector convergence, (d) the most positive curvature, (e) the most negative curvature, and (f) total aberrancy.

254x190mm (300 x 300 DPI)
Figure 20. The histogram for the azimuth of (blue bars) maximum in-situ horizontal stress and the azimuth/strike (red bars) of (a) the most positive principal curvature $k_1$, (b) the most negative principal curvature $k_2$, (c) reflector convergence, (d) the most positive curvature, (e) the most negative curvature, and (f) total aberrancy.

254x190mm (300 x 300 DPI)
Figure 20. The histogram for the azimuth of (blue bars) maximum in-situ horizontal stress and the azimuth/strike (red bars) of (a) the most positive principal curvature $k_1$, (b) the most negative principal curvature $k_2$, (c) reflector convergence, (d) the most positive curvature, (e) the most negative curvature, and (f) total aberrancy.

254x190mm (300 x 300 DPI)
Figure 20. The histogram for the azimuth of (blue bars) maximum in-situ horizontal stress and the azimuth/strike (red bars) of (a) the most positive principal curvature $k_1$, (b) the most negative principal curvature $k_2$, (c) reflector convergence, (d) the most positive curvature, (e) the most negative curvature, and (f) total aberrancy.
Figure 20. The histogram for the azimuth of (blue bars) maximum in-situ horizontal stress and the azimuth/strike (red bars) of (a) the most positive principal curvature $k_1$, (b) the most negative principal curvature $k_2$, (c) reflector convergence, (d) the most positive curvature, (e) the most negative curvature, and (f) total aberrancy.

254x190mm (300 x 300 DPI)
Figure 20. The histogram for the azimuth of (blue bars) maximum in-situ horizontal stress and the azimuth/strike (red bars) of (a) the most positive principal curvature $k_1$, (b) the most negative principal curvature $k_2$, (c) reflector convergence, (d) the most positive curvature, (e) the most negative curvature, and (f) total aberrancy.

254x190mm (300 x 300 DPI)
Figure 21. Crossplot of interpreted azimuth and predicted azimuth using (a) seismic RMS amplitude, (b) seismic maximum amplitude, (c) seismic amplitude, (d) seismic dominant frequency, (e) seismic instantaneous amplitude, and (f) seismic instantaneous frequency varying with azimuth at the locations of microseismic ruptures.

279x215mm (300 x 300 DPI)
Figure 21. Crossplot of interpreted azimuth and predicted using (a) seismic RMS amplitude, (b) seismic maximum amplitude, (c) seismic amplitude, (d) seismic dominant frequency, (e) seismic instantaneous amplitude, and (f) seismic instantaneous frequency varying with azimuth at the locations of microseismic ruptures.

279x215mm (300 x 300 DPI)
Figure 21. Crossplot of interpreted azimuth and predicted using (a) seismic RMS amplitude, (b) seismic maximum amplitude, (c) seismic amplitude, (d) seismic dominant frequency, (e) seismic instantaneous amplitude, and (f) seismic instantaneous frequency varying with azimuth at the locations of microseismic ruptures.

279x215mm (300 x 300 DPI)
Figure 21d

Figure 21. Crossplot of interpreted azimuth and predicted using (a) seismic RMS amplitude, (b) seismic maximum amplitude, (c) seismic amplitude, (d) seismic dominant frequency, (e) seismic instantaneous amplitude, and (f) seismic instantaneous frequency varying with azimuth at the locations of microseismic ruptures.
Figure 21. Crossplot of interpreted azimuth and predicted using (a) seismic RMS amplitude, (b) seismic maximum amplitude, (c) seismic amplitude, (d) seismic dominant frequency, (e) seismic instantaneous amplitude, and (f) seismic instantaneous frequency varying with azimuth at the locations of microseismic ruptures.

279x215mm (300 x 300 DPI)
Figure 21. Crossplot of interpreted azimuth and predicted using (a) seismic RMS amplitude, (b) seismic maximum amplitude, (c) seismic amplitude, (d) seismic dominant frequency, (e) seismic instantaneous amplitude, and (f) seismic instantaneous frequency varying with azimuth at the locations of microseismic ruptures.

279x215mm (300 x 300 DPI)
Figure 22a

Caption: Figure 22. Crossplot of interpreted azimuth and predicted using (a) the most positive principal curvature $k_1$, (b) the most negative principal curvature $k_2$, (c) reflector convergence, (d) the most positive curvature, (e) the most negative curvature, and (f) total aberrancy.

279x215mm (300 x 300 DPI)
Figure 22. Crossplot of interpreted azimuth and predicted using (a) the most positive principal curvature $k_1$, (b) the most negative principal curvature $k_2$, (c) reflector convergence, (d) the most positive curvature, (e) the most negative curvature, and (f) total aberrancy.

279x215mm (300 x 300 DPI)
Figure 22. Crossplot of interpreted azimuth and predicted using (a) the most positive principal curvature $k_1$, (b) the most negative principal curvature $k_2$, (c) reflector convergence, (d) the most positive curvature, (e) the most negative curvature, and (f) total aberrancy.

279x215mm (300 x 300 DPI)
Figure 22. Crossplot of interpreted azimuth and predicted using (a) the most positive principal curvature $k_1$, (b) the most negative principal curvature $k_2$, (c) reflector convergence, (d) the most positive curvature, (e) the most negative curvature, and (f) total aberrancy.
Figure 22. Crossplot of interpreted azimuth and predicted using (a) the most positive principal curvature $k_1$, (b) the most negative principal curvature $k_2$, (c) reflector convergence, (d) the most positive curvature, (e) the most negative curvature, and (f) total aberrancy.

279x215mm (300 x 300 DPI)
Caption: Figure 22. Crossplot of interpreted azimuth and predicted using (a) the most positive principal curvature $k_1$, (b) the most negative principal curvature $k_2$, (c) reflector convergence, (d) the most positive curvature, (e) the most negative curvature, and (f) total aberrancy.

279x215mm (300 x 300 DPI)
Figure 23. The histogram of long axis of fitted anisotropic ellipsoid computed using seismic dominant frequency for the target formation.
Table 1. Correlating the computed azimuth/strike of seismic attribute with the interpreted strike of natural faults using image log at the Well A location.

<table>
<thead>
<tr>
<th>Image Log</th>
<th>Two sets, the azimuths of natural fractures are 10 and 70.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-stack attribute</td>
<td>MA</td>
</tr>
<tr>
<td>Predicted Azimuth</td>
<td>144</td>
</tr>
<tr>
<td>Post-stack attribute</td>
<td>K1</td>
</tr>
<tr>
<td>Predicted Azimuth</td>
<td>48</td>
</tr>
</tbody>
</table>

(Remarks: MA stands for maximum amplitude, RMSA stands for root mean square amplitude, AVAz stands for amplitude versus with angle and azimuth, FVAz stands for dominant frequency versus with angle and azimuth, IA stand for instantaneous amplitude, IF stand for instantaneous frequency. k1 stands for the most positive principal curvature, k2 stands for the most negative principal curvature, RC stands for the reflector convergence, MP stands for the most positive curvature, MN stand for the most negative curvature, TA stand for the total aberrancy.)

Table 2. Correlating the computed azimuth/strike of seismic attributes with the azimuth of maximum in-situ stress using image log at the Well A location

<table>
<thead>
<tr>
<th>Image Log</th>
<th>One set, the azimuth induced fractures is 140</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-stack attribute</td>
<td>MA</td>
</tr>
<tr>
<td>Predicted Azimuth</td>
<td>144</td>
</tr>
<tr>
<td>Post-stack attribute</td>
<td>K1</td>
</tr>
<tr>
<td>Predicted Azimuth</td>
<td>48</td>
</tr>
</tbody>
</table>

(Remarks: MA stands for maximum amplitude, RMSA stands for root mean square amplitude, AVAz stands for amplitude versus with angle and azimuth, FVAz stands for dominant frequency versus with angle and azimuth, IA stand for instantaneous amplitude, IF stand for instantaneous frequency. k1 stands for the most positive principal curvature, k2 stands for the most negative principal curvature, RC stands for the reflector convergence, MP stands for the most positive curvature, MN stand for the most negative curvature, TA stand for the total aberrancy.)
DATA AND MATERIALS AVAILABILITY

Data associated with this research are confidential and cannot be released.