Azimuthal anisotropy analysis applied to naturally fractured unconventional reservoirs: A Barnett Shale example

Jing Zhang1, Jie Qi2, Yijin Zeng3, Kurt Marfurt2, and Roger Slatt2

Abstract

Studying the seismic responses of velocity and amplitude on wide-/full-azimuth seismic data is now common for unconventional reservoir characterization. Velocity variation with azimuth (VVAz) and amplitude variation with azimuth (AVAz) are two of the most popular tools to map not only the relative intensity and orientation of natural fractures but also the strength and orientation of the maximum horizontal stress $S_H$. We prestack time migrated a wide-azimuth Barnett Shale survey in North Texas into eight azimuths and reduced noise on the gathers using prestack structure-oriented filtering. We then computed the envelope, spectral peak frequency, and prestack $P$-wave impedance attributes for each azimuthally limited seismic volume. We compensated the VVAz effects by flattening each sector along the Barnett Shale key horizons, thereby registering the gathers for subsequent AVAz analysis. The results indicate the intensity, orientation, and confidence of azimuthal anisotropy effects on seismic velocity and amplitude, which can be referred to smaller scale vertical cracks or natural fractures. Our analysis reveals four zones of high anisotropy intensity that can be tied to either the regional structures or paleo stress field. Analysis of production data indicate from the anisotropy interpretation results that vertical, sealed fractures are the dominant cause of anisotropy and those specific fractures inhibit production. This observation and results indicate that horizon-based azimuthal anisotropy analysis avoids the VVAz effect and can be applied to fractures and regional stress field prediction.

Introduction

The strike orientation of open microcracks, which represents the present-day stress field, plays a key role in allocating and developing shale resource plays. Our goal is to determine if the anisotropy obtained from amplitude variation with azimuth (AVAz) analysis of a wide-azimuth survey can be correlated to natural fracture distribution and orientation in a shale reservoir. Residual moveout analysis and near core characterization indicate that the Barnett Shale reservoir exhibits moderate horizontal transverse isotropy (HTI) and relatively weak layering-induced vertical transverse isotropy (Gale et al., 2007, 2010, 2014). The moderate intensity of azimuthal anisotropy allows us to use Tomensen (1986) anisotropy analysis. We assume that the main cause of azimuthal anisotropy in the survey is attributed to microcracks that are open perpendicular to the minimum horizontal stress.

Natural fracture characterization

Natural fracture occurrence in unconventional shale reservoirs has received considerable attention because of its potential impact on reservoir quality characterization. Numerous studies have been conducted based on outcrop, core, and subsurface data to understand the origin, preferential distribution pattern, and impact factors on fracture occurrence (Nelson, 2001; Curtis, 2002; Gale et al., 2007; Olson and Taleghani, 2009; Gale and Holder, 2010; Cho et al., 2013).

Due to limited access to subsurface data, field fracture characterization is commonly used as an analog (Hennings et al., 2000; Nelson, 2001; Olson and Taleghani, 2009; Milad et al., 2018). Outcrop analogs provide linkage between natural fracture density with bedding thickness and composition. However, other controlling factors include variability in deformational history, initial burial depth, and confining pressure are involved in complexity as well (Hanks et al., 1997; Bai and Pollard, 2000; Nelson, 2001; Galvis-Portilla et al., 2016; Ghosh, 2017).

Compared to outcrop analogue characterization, fractures seen in drilled core or downhole image logs are more direct ways to quantify fractures under reservoir conditions. However, such objectives provide only

1 University of Oklahoma, Norman, Oklahoma 73071, USA and State Key Laboratory of Shale Oil and Gas Enrichment Mechanism and Effective Development, Beijing, China. E-mail: jing.zhang@ou.edu
2 University of Oklahoma, Norman, Oklahoma 73071, USA. E-mail: jie.qi@ou.edu (corresponding author); kmarfurt@ou.edu; rslatt@ou.edu.
3 State Key Laboratory of Shale Oil and Gas Enrichment Mechanism and Effective Development, Beijing, China. E-mail: zengyj.sripe@sinopec.com. Manuscript received by the Editor 23 September 2019; revised manuscript received 20 December 2019; published ahead of production 29 May 2020; published online 26 June 2020. This paper appears in Interpretation, Vol. 8, No. 4 (November 2020); p. SP13–SP29, 20 FIGS., 1 TABLE. http://dx.doi.org/10.1190/INT-2019-0206.1 © 2020 Society of Exploration Geophysicists and American Association of Petroleum Geologists. All rights reserved.
a local, 1D knowledge of the subsurface, which may be
difficult to extrapolate to three dimensions (Narr and
Lerche, 1984; Lorenz and Hill, 1992; Narr, 1996; Nelson,
2001; Fernández-Ibáñez et al., 2018).

A more promising workflow for 3D fracture analysis
on a larger scale is to tie the relatively qualitative but
dense 3D seismic response to the more quantitative
sparse well control. Seismic-based analysis can be ap-
plied on natural fractures and hydraulic fractures (Tsvan-
kin and Grechka, 2011; Liu, 2013; Yuan et al., 2018).
However, the limited resolution of seismic data with
wavelengths of approximately 50 m is challenging to
show small-scale (on the order of 10 m), detailed features
such as fracture spacing in the Barnett Shale. Even
though there are indications of scattering from fractured
zones, details on the orientation and density of the frac-
ture system are still hard to verify (Liu, 2013). Neves et al.
(2004), Chopra and Marfurt (2007), and Guo et al. (2010)
find correlations between the fracture distribution and
seismic attributes such as coherence and curvature. Out-
crop analysis and finite element models show a good cor-
relation of fractures to the proximity of faults and the
intensity of folding, which in turn can be mapped by seis-
mic attributes such as coherence and curvature (Busetti
et al., 2012). The presence of such fractures is “inferred
using a deformation model. In contrast, AVAz provides a
more direct measure of the presence of natural fractures
and stress direction (Liu, 2013).

Anisotropy

The existence of natural fractures or discontinuities in
subsurface are known to influence the traveltimes and
amplitudes of seismic waves (Anderson et al., 1974; Kus-
ter and Toksöz, 1974; Boadu, 1995; Boadu and Long,
1996). When clustered fractures are near vertical and
maintain a consistent strike direction, the medium will
exhibit HTI (Wang, 2002; Helbig and Thomsen, 2005;
Tsvankin and Grechka, 2011; Liu, 2013; Alali, 2018; Shi
et al., 2018). Seismic compressional wave (P-wave)
propagation will be affected when passing through the
HTI medium with a corresponding azimuthal variation:
(1) a slowed P-wave velocity with the maximum velocity
attenuation orthogonal to the fracture plane (fracture
strike orientation) and a faster P-wave velocity along
the fracture plane (fracture strike orientation) (Ander-
sen et al., 1974; Kuster and Toksöz, 1974; Boadu, 1995;
Clifford et al., 2005). This variation results in different
arrival times and reflection coefficients for the source-
receiver on different azimuths. (2) P-wave attenuation
due to scattering with the maximum extent when perpen-
dicular to the fracture strike direction, which can be
relected as the amplitude and other amplitude-relat-
ed seismic attributes attenuation (Maultzsch et al.,
2007; Thompson et al., 2010). The amplitude attenuation
can be observed from different azimuths and offsets
(Samec and Blangy, 1992; Zhu et al., 2007; Sharma et al.,
2018) (Figure 1).

AVAz of azimuthally sectored migrated seismic data
provides a means to map the intensity and orientation
of the HTI medium anisotropy (Gray and Head, 2000;
Rüger, 2002; Gray et al., 2003; Gray, 2008; Mahmoudian
et al., 2013; Liu, 2014; Qi et al., 2015; Wang et al., 2015).
AVAz analysis requires the acquisition of wide-/full-azi-
muth seismic data with sufficient offsets (Rüger, 2002).
Thompson et al. (2010) show how one can calculate the
intensity (c), azimuth (Ψ), and confidence (c) of these
measures by fitting an ellipse to the different azimuth
volumes in each gather for HTI media.

For this case study, we began with conducting seis-
mic interpretation on eight azimuthal gather from one
wide-azimuth survey and then we calculated the ampli-
tude-related seismic attributes for each azimuthal
gather; next, we flattened the attribute based on seismic
key horizons from interpretation and input into AVAz
workflow to obtain the key parameters of anisotropy.
We conclude the relationship between natural fractures
distribution and seismic azimuthal anisotropy by com-
paring with the gas production map in the study area.

Geologic background

This case study targets the Barnett Shale in the Fort
Worth Basin, North Texas, USA (Figure 2). The Missis-
sippian-age Barnett Shale is an organic-rich shale gas res-
ervoir exploited in North America (Singh et al., 2008).
The Fort Worth Basin is a foreland basin formed during
the late Paleozoic due to the Ouachita orogeny (Walper,
1981; Thompson, 1988). The basin is bounded by the Red
River Arch and the Muenster Arch in the north, the
Ouachita Thrust-Fold Belt in the east, the Llano Uplift
paleohigh in the south, and the Bend Arch in the west.
Within the basin, the major Mineral Wells Fault is ori-
ented in a northeast–southwest direction (Pollastro et al.,
2007) (Figure 2).
Before deposition of the Barnett Shale, the Ellenburger Group carbonates formed a broad epeiric platform and later underwent subaerial erosion and karsting, which formed an unconformity on the Ellenberger and Viola limestone surfaces (Kerans, 1988; Gasparrini et al., 2014). The Barnett Shale was deposited on top of this unconformity during the transition from the uplifted area to a foreland basin (Henry, 1982; McBee, 1999). The Barnett Shale Formation is subdivided into the Upper and Lower members. The Forestburg Limestone occurs between the two members regionally in the northeast part of the basin where our survey lies and pinches out toward the south (Henry, 1982; Bowker, 2003; Montgomery et al., 2005; Gasparrini et al., 2014). Generally, the thickness of the Barnett varies from fewer than 50 ft in the southern part of the basin (the Bend Arch and Llano Uplift area) to more than 1000 ft thick in the northern part (the Muenster Arch area) (Montgomery et al., 2005; Pollastro et al., 2007). In total, 10 lithofacies of the Barnett Shale were identified by Abouelresh and Slatt (2012) from a core in Johnson County based on the composition and sedimentary structures to represent the general geologic characteristics of the Barnett Shale.

**Basin structural settings and fractures**

The natural fractures in the Barnett Shale have been documented in many studies especially in the Fort Worth Basin. Gasparrini et al. (2014) conduct petrographic analyses of sealed natural fractures from cores and outcrops and identified four episodes of fracture generation, representing different compaction conditions, thermal regimes, and times. Bowker (2007) indicates that the overpressure within the Barnett Shale proves that open natural fractures are rare. Commercial oil and gas companies found that the natural fracture density increases adjacent to fault zones. However, most of the fractures are sealed with carbonate cements, which reduces the reservoir porosity and provides little contribution to fluid flow during production (Bowker, 2003, 2007; Gale et al., 2010). Gale et al. (2007) report that most sealed natural fractures are likely clustered with at least two sets of orientation: the older north-south trending sets and the younger west-northwest–east-southeast-trending set. The current-day stress field near the study area has a maximum horizontal stress orientation of northeast–southwest (Lund Snee and Zoback, 2016) (Figure 3). Seismic attributes have also been applied to the region for structural interpretation and karst collapse analysis. Seismic attribute-related study also emphasizes that total organic carbon and mineralogical composition derived from seismic data can determine brittleness of the Barnett Shale (Perez Altamar and Marfurt, 2014). Verma et al. (2016) also present a way to compute brittleness using neural network and seismic attributes and inversion results on the Barnett Shale.

**Regional structural analysis**

The 3D seismic survey falls within the Newark East Field, Wise County, Texas. In this area, the Barnett Shale is approximately 500 ft thick with approximately 100 ft thick Forestburg Lime contained in the middle of the formation. The average Barnett burial depth is approximately 5000 ft and mainly produces gas (Figure 2). Using coherence and curvature seismic attributes, two major faults (named fault A and fault B in Figure 4) that are striking northeast–southwest can be visualized; the dip direction and spatial distribution can be better

![Figure 2. Major structural features of the Fort Worth Basin and production type distribution (original image by Pollastro et al., 2007). The location of the case study area is highlighted with the blue dot.](image-url)
observed after fault interpretation, which indicates dipping toward the northwest for both faults (Figure 5). Although strike-slip motion is difficult to capture on seismic, the regional stress map by Lund Snee and Zoback (2016) (Figure 3) indicates that strike-slip deformations are involved with normal fault displacement. Faults A and B are slightly curved in the northern end, and fault planes are compartmentalized according to the coherence attribute. The compartmentalization can be interpreted due to the strike-slip shear movement in a thrust-fold transfer zone. According to the seismic interpretation and published literature (Adams, 2003; Montgomery et al., 2005; Pollastro et al., 2007), these two normal faults belong to the Mineral Wells Fault system and share the same deformation mechanism. The faults originate from the basement and stop growing at the top of the Barnett Shale indicating that the general deformation stopped by late Mississippian time (Baruch et al., 2009) (Figure 5).

The average strike of faults A and B was measured along the fault line based on a stratal slice along the base Barnett/top Viola in coherence and curvature attributes; generally, fault A has an average strike orientation of 47° and fault B has an average strike orientation of 62° (Table 1).

Because faults A and B are in a normal/lateral strike slip regime, $\sigma_1$ is vertical, $\sigma_2$ ($S_{Hmax}$) was in a northeast–southwest trend parallel to fault A and B’s strike orientations, and $\sigma_3$ ($S_{hmin}$) is perpendicular to the $\sigma_2$ ($S_{Hmax}$) (Figure 6). In such a combined fault regime, $\sigma_1$ ($S_v$) = $\sigma_2$ ($S_{Hmax}$) > $\sigma_3$ ($S_{hmin}$), which indicates that the magnitude of vertical stress could be slightly larger or similar to the maximum horizontal stress. As a result, vertical natural fractures formed together with deformation of the faults following the general orientation of strike along $S_{Hmax}$ and expected an increase in density adjacent to the fault plane. However, smaller scale fracture orientations could vary and may be complex.

Methodology

In 2006, Devon Energy acquired a wide-azimuth prestack seismic survey (before hydraulic fracturing), which we reprocessed into eight azimuthally limited gather volumes (Figure 7). Our workflow is an expansion of the one used by Zhang et al. (2013) and Guo et al. (2016) (Figure 8). The first quality control step is to conduct structure-oriented filtering to reduce noise from the original seismic data (Figure 9). We then corrected for the velocity variation with azimuth (VVAz) effect by manually picking four key geologic horizons top Barnett (TB), base upper Barnett (BUB), top lower Barnett (TLB), and base Barnett (BB) on each azimuthally limited volume (Figure 10). Examining Figure 11, note that azimuths 6 and 7 have the weakest seismic amplitude, whereas azimuths 3 and 4 have the strongest amplitude. Arrival time

Figure 3. Stress map of Texas showing the maximum horizontal stress orientation (original image by Lund Snee and Zoback, 2016). The study area is highlighted in the blue circle, the FWB represents the Fort Worth Basin and indicates that the current-day maximum horizontal stress is trending northeast–southwest, and the colors indicate that the study area locates within a strike-slip fault and normal fault transition regime.

Figure 4. Strata slice (base Barnett) through (a) coherence and (b) most positive and negative curvature corender maps. Two major normal faults are delineated by the orange dashed lines, both of which are subparallel to the Mineral Wells Fault (not included in the survey).
differences between the four key horizons provided the indication of VVAz effect. In addition to AVAz, we also examined variation in seismic attributes including envelope, spectral peak frequency, and prestack P-impedance. The final output is the ε (intensity of the anisotropy), Ψ (azimuth of the largest attribute value), and c (confidence of the least squares fit) along the interpreted horizons each of these attributes on each azimuth. Among those outputs, Ψ (azimuth of the minimum variation) can be used to represent the fracture strike orientation in an HTI medium.

**Attributes for anisotropy analysis**

We selected several amplitude- and velocity-related seismic attributes in addition to the amplitude itself to conduct anisotropy analysis. Attribute volumes on each azimuthal gather were calculated and then extracted along the key horizons interpreted from that corresponding azimuthal gather to input in anisotropy analysis. All the attributes are expected to reflect the anisotropy effect along the extracted horizons and compared with support the final conclusions.

The envelope (also called the “reflection strength” or “amplitude envelope”) is often used to determine the lateral

<table>
<thead>
<tr>
<th>Measurement</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
<th>8</th>
<th>9</th>
<th>10</th>
<th>11</th>
<th>Avg</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fault A</td>
<td>48</td>
<td>48</td>
<td>46</td>
<td>47</td>
<td>53</td>
<td>43</td>
<td>47</td>
<td>43</td>
<td>53</td>
<td>56</td>
<td>37</td>
<td>47</td>
</tr>
<tr>
<td>Fault B</td>
<td>63</td>
<td>70</td>
<td>62</td>
<td>49</td>
<td>65</td>
<td>63</td>
<td>52</td>
<td>57</td>
<td>71</td>
<td>64</td>
<td>69</td>
<td>62</td>
</tr>
</tbody>
</table>

**Figure 6.** The regional stress field interpretation is based on observed structures and the regional fault. The maximum horizontal stress follows orientation parallel to the strike of faults A and B. The local stress field and structure cannot be represented by the regional stress field.
variation in reservoirs. It calculates the absolute value of the complex trace magnitude (White, 1991; Chen and Sidney, 1997; Russell et al., 1997; Taner, 2001; Chopra and Marfurt, 2007). The magnitude of the trace envelope attribute is proportional to the acoustic impedance contrast (Russell et al., 1997; Taner, 2001) and is mathematically described as

\[ e(t) = \left[ u^2(t) + u_H^2(t) \right]^{1/2} \]  

(1)

where \( e(t) \) is the amplitude envelope, \( u(t) \) is the seismic trace, and \( u_H(t) \) is its Hilbert transform trace (Taner and Sheriff, 1977; Russell et al., 1997). The envelope is directly related to the reflectivity and thus can be used as an input for anisotropy analysis.

The spectral peak frequency was calculated as one output of spectral decomposition analysis by least-squares fitting using a complex matching pursuit method (Liu and Marfurt, 2007). The peak frequency represents the spectral frequency that corresponds to the greatest spectra magnitude. The seismic wave amplitudes become attenuated exponentially with time and depth when traveling in the subsurface; this amplitude attenuation effect especially affects the high-frequency spectrum (Li et al., 2015, 2016a). The quantifying amplitude attenuation from the seismic spectral frequency band is commonly applied to various subsurface characteristics such as rock properties, anisotropy, and structures.

**Figure 7.** Eight different azimuthal bins covering the full azimuth range with a 22.5° increment using the method proposed by Perez and Marfurt (2008).

**Figure 8.** Workflow for azimuthal anisotropy analysis and interpretation. The data should be preprocessed, and then the target horizons are interpreted manually for each azimuthal volume to compensate for the velocity anisotropy effect. The extracted attributes along key horizons were input for anisotropy analysis, respectively. The output includes three key parameters of anisotropy: intensity, azimuth, and confidence.
(Schoenberg and Douma, 1988; Lynn and Beckham, 1998; MacBeth, 1999; Carcione, 2000; Clark et al., 2009; Li et al., 2015). Maultzsch et al. (2007) and Wang et al. (2015) indicate that high-frequency seismic components attenuate more rapidly than low-frequency components and seismic attenuation increases with frequency. Higher frequency variation can be used to indicate the higher extent of amplitude attenuation and then indirectly refers to higher anisotropy in the HTI medium. Thus, the AVAz outputs from the spectral peak frequency attribute can be used to infer intensity of anisotropy; however, azimuth outputs are in an orthogonal relationship with amplitude-related attributes because the azimuth of the largest spectral peak frequency represents the highest amplitude attenuation orientation that is perpendicular to the fracture strike orientation and other amplitude AVAz azimuth output (Li et al., 2016b).

The prestack P-wave impedance is obtained by integrating P-wave shear wave (S-wave) velocity, and bulk density logs from five wells located within the seismic survey. Impedance is an ideal property to represent azimuthal velocity and amplitude variation and attenuation for anisotropy analysis. Thompson (2010) applies prestack inversion analysis to detect induced fractures in the Barnett Shale. The prestack P-wave impedance is calculated from the far offset gathers because those gathers are more sensitive to minor anisotropy effects (Lynn and Beckham, 1998; Maultzsch et al., 2007). We limited our analysis to 25°–35° angle to represent far offset gathers. A well log time to depth correlation was conducted on all five wells based on the interpreted formation top and base from each azimuthal poststack seismic volume (Figure 12). A good correlation chart between the inverted P-wave impedance with the log P-wave impedance for each azimuth inversion result indicates a reliable input for anisotropy analysis (Figure 13). Phantom horizons were generated as close as possible to the original interpreted horizons (10 ms below the TB) and (15 ms below the TLB) for each azimuth to guarantee that the attribute flattened input maintains the stable, representative interval inversion properties that are comparable with the other anisotropy analysis input attributes (Figure 14).

**Results**

Anisotropy analysis was conducted on all seismic attributes, and the results show a consistent location of high-anisotropy-intensity zones and interpreted fracture strike azimuth. The confidence of the highlighted anisotropy zone is high, which excludes the possibility that the anisotropy is induced by noise and seismic processing. The results of each anisotropy attribute analysis are introduced below.

**Amplitude variation with azimuth**

AVAz highlights four areas with high anisotropy intensity indicated as A, B, C, and D, respectively, on Figure 15. These high-anisotropy-intensity zones are all located within the area with low coherence, which indicates that the topographic discontinuity is negligible for natural fractures and makes it hard to be captured by regular seismic coherence attributes. The high-anisotropy zones

![Figure 9. Coherence attributes on (a) before structure-oriented filtering and (b) after structure-oriented filtering. Note that after the denoising, the amplitude is preserved better to illustrate structures.](image)

![Figure 10. Four key formation top horizons picked in the seismic survey. (a) Inline view showing the thickness relationship of the Upper Barnett, Lower Barnett, and Forestburg Lime. (b) Four interpreted horizons in 3D view. For each azimuthal volume, the horizons were picked separately.](image)
are close to fault areas, which supports the assumption that small-scale deformations are more intense adjacent to large-scale deformations.

Four key geologic horizons showed consistent locations of the high-anisotropy zones. The intensity and area of distribution increases from the TB to the BUB, and then it decreases downward and reaches the lowest intensity until the BB (Figure 16). This indicates that the base of the Barnett Shale could have fewer vertical natural fractures distributed than the Upper Barnett Shale. This phenomenon can be explained and supported by many field observations that the most intense and uniformly oriented deformation was distributed at the tip of the fault plane during growth of the fault (Chinnery, 1966; Cowie and Scholz, 1992; Anders and Wiltshko, 1994; Reches and Lockner, 1994; Cowie and Shipton, 1998; Vermilye and Scholz, 1998; Katz et al., 2003). The azimuth of the maximum anisotropy, which is interpreted as the strike orientation of the vertical fractures shows an azimuth of 30°–60° throughout the entire formation for zones A and D. Zones B and C have a slight change in the fracture strike direction between the Upper Barnett and Lower Barnett Shales. Zone B anisotropy is oriented west–east at the TB and TLB surfaces and then changes orientation (northeast–southwest) for the BUB and BB surfaces. Zone C has an orientation of north-northwest–south-southeast throughout the formation.

**Envelope attribute anisotropy analysis**

The envelope attribute anisotropy analysis is expected to show better results than amplitude analysis because the envelope attribute has reduced the picking errors by calculating the absolute values of seismic amplitude. The anisotropy analysis highlights the same location for the four high-anisotropy zones; the intensity result is the same as the amplitude result: increasing from the TB toward the BUB then decreasing toward the BB. The azimuth of maximum anisotropy is more consistent among the four key horizons than the amplitude analysis result (Figure 17). Zones A, B, and D maintain a similar northeast–southwest trend of approximately 50° strike throughout the formation; zone C has a similar northeast with amplitude analysis, which is different from the other high-anisotropy zones: the north–south trend on all four horizons. The envelope results are less patchy and of higher consistency than the amplitude result, which makes it more reliable than seismic amplitude anisotropy analysis.

![Figure 11](https://example.com/figure11.png)

**Figure 11.** Azimuthal seismic volumes comparison from the cross section obtained from the northwest part of the study area. The color code represents the magnitude of the amplitude. Note that the amplitude varies by azimuthal volume and the arrival time of four key horizons highlighted in green are different after manually interpreting the horizons. The interpretation uses 2D seed picking for each volume and checked manually afterward to avoid any manually picking error.
Figure 12. Seismic impedance calculation and well tie procedure. Because of anisotropy and acquisition parameters, the effective seismic wavelet for each azimuthal sector is slightly different. We, therefore, generated well ties for each volume. Note that the Forestburg Lime can be easily identified from the low gamma-ray log as well as the density contrast, which leads to an increase in impedance and velocity within the Forestburg. The seismic section is the well-intersected inline, and the gray-filled trace is the specific intersected trace. The diagram shows the result after the well tie and matched wells with velocity profile and interpreted seismic horizons.

Figure 13. P-wave impedance results from model and log crossplot shows a reliable correlation of the calculation result on each azimuth, confirming the reliability for further anisotropy calculations.
Spectral peak frequency attribute anisotropy analysis

Spectral peak frequency seismic attribute anisotropy analysis highlighted the same four zones of high anisotropy as the amplitude and envelope anisotropy result (Figure 18). The original peak frequency data are very patchy with low pixel resolution, which makes it difficult to reveal the similar anisotropy analysis result with the other attributes. Thus, the spectral peak frequency was calculated and then smoothed before anisotropy analysis. The intensity results show an increasing trend downward. Zones A, B, and C can be identified from the top three horizons. The azimuth distribution result shows an orthogonal relationship with the other attributes outputs as expected. Zones A, B, and D have an azimuth of northwest–southeast (N40W) throughout the formation, and zone C has a west–east orientation. These azimuth outputs indicate the maximum peak frequency orientation, which corresponds with maximum amplitude attenuation that is perpendicular to the fracture strike.

Prestack P-impedance anisotropy analysis

The P impedance calculated from prestack inversion allows extracting the interval property of the Upper and Lower Barnett Shale, respectively. Because extracting the inversion result along the formation boundary is prone to collect the error from horizon picking, the reflection boundary is not an ideal representative of the interval property. As introduced earlier, to present the impedance value that is comparable to the other attributes, the 10 and 15 ms phantom horizons were generated below the top Upper Barnett (TUB) and TLB, respectively, for the impedance result flattening on each volume as input for anisotropy analysis. As shown in Figure 19, the anisotropy analysis results on intensity and azimuth for the Upper and Lower Barnett Shales reveal the same location of zones A, B, C, and D. However, the distribution is patchy compared with the former results, which is interpreted as the phantom horizon bias. The azimuths of the maximum anisotropy zones are identical with the previous results.

Generally speaking, the four attributes’ anisotropy analyses all indicate four zones of high anisotropy intensity: Zones A, B, C, and D as highlighted on Figure 15, and all four zones are adjacent to the fault lines. The location of the high-intensity zones corresponds with high confidence value for all analyses, which confirms the high reliability of the results. Zone B is located in between faults A and B, which indicates that it is most likely affected by both faults. Zone D has a linear geometry that is subparallel to fault B, which indicates that the anisotropy is more likely induced by fault B deformation. Among all of the attributes, envelope is the attribute with higher quality output with consistent intensity and azimuth, non-patchy results throughout the formation.

The intensity of anisotropy from all of these analyses indicates a higher intensity of anisotropy in the Upper Barnett than the Lower Barnett: There is generally an increase from the TUB to the BUB, and then the intensity decreases toward the BB. The highest intensity in the BUB surface and the bigger area of distribution indicate that the fracture density is higher in the Upper Barnett Shale because it is close to the tip of the fault and experienced a higher intensity of smaller scale deformation.

The azimuths of the high-intensity zones are different, which implies the potentially different deformational mechanisms and timing of the natural fractures. Zones A, B, and D natural fractures generally share a
50° northeast–southwest or north-northeast–south-southwest orientation, which is subparallel to faults A and B's strike and interpreted paleo maximum horizontal stress orientation from regional structural analysis. This indicates that the natural fractures in zones A, B, and D were formed under the same stress field, mechanism, and time with faults A and B. Zone C fractures have a north–south strike orientation, which indicates that these fractures formed under the impact of the older stress field according to Gale et al. (2007) and are less impacted by faults A and B. The location of zone C is also relatively isolated from the fault lines, which confirms the conclusion of a different stage of zone C formation than zones A, B, and D.

**Result verification with production map**

To verify that the anisotropy analysis results are associated with the natural fracture network, a first-year lateral well gas production map from the Barnett Shale within the study area was generated based on public data source IHS and corendered with the amplitude anisotropy intensity map of the BUB (Figure 20). The lateral wells are mostly extended in a northeast–southwest direction. Gas production was standardized based on the well lateral length. Where the low-anisotropy zones are in blue color, the production is optimistic and it performs generally better than in the high-anisotropy-intensity zones. The high-production areas are located near the fault lines, which indicates that the operators tried to reach the faulted area with higher reservoir connectivity due to the larger scale deformation to enhance production. On the contrary, high anisotropy zone A, B, C, D has fewer production wells positioned, which means that the operators may have avoided the anisotropy area due to the low-production prediction from the other interpretation. Where there is some production in the high-intensity zone, such as zone D and the northeast edge of zone A, the production is not optimistic compared with the other areas of production. This observation corresponds with former studies in that the natural fractures in the Barnett Shale in this area are mostly sealed.

**Figure 16.** Amplitude anisotropy analysis results along the four key horizons shows the intensity, azimuth, and confidence of the anisotropy. The anisotropy intensity decreases geologically downward, and the upper Barnett generally has higher intensity at all four anisotropy zones than the Lower Barnett Shale. The azimuth of zones A and D (the location is indicated in Figure 13) is generally consistent with a northeast–southwest trend. Zones B and C have slightly different azimuths, but the locations are consistent throughout the formation.

**Figure 17.** Envelope attributes anisotropy analysis result. The intensity result is similar to the amplitude result, and the azimuth shows a more consistent northeast–southwest trend for zones A, B, and D; zone C has a different north–southtrending azimuth. Confidence at the high-intensity zones is high, making the result reliable for further interpretation.
and inhibit the fluid flow in the reservoir (Bowker, 2007; Gale et al., 2007; Gale and Holder, 2010; Gasparini et al., 2014). The hydraulic fracturing triggers a more complex network, which is not beneficial to unconventional production for this case (Bowker, 2003, 2007; Gasparini et al., 2014). The other high-production near high-anisotropy area, such as the southeast of zone A and the southeast of zone C, is most likely due to the proximity to the fault A plane. The moderate production mostly corresponded with the green-level moderate anisotropy. The production map further supports the assumption that the high-anisotropy zones are introduced by sub-seismic-scale vertical natural fractures.

**Discussion**

The fault lines, as larger scale deformations, can be highlighted not only in the coherence and curvature seismic attributes but also in anisotropy analysis results (Figures 16–19). The presence of the fault is associated with low anisotropy intensity, which can be interpreted as fault lines having uniform large-scale discontinuity compared with the smaller scale discontinuity such as a fracture network. The fracture network has higher internal anisotropy because the strike and geometry vary and are impossible to keep uniformly throughout the formation either laterally or vertically. Thus, a fault in the azimuthal anisotropy analysis displays a low anisotropy intensity with linear geometry. The maximum anisotropy azimuth on each side of the fault plane might be altered as displayed (Figures 16–19).

According to Perez Altamar and Marfurt (2014), the Upper Barnett Shale in the study area is dominated by carbonate-rich lithofacies, and the Lower Barnett Shale is dominated by quartz-rich lithofacies; this lithology change can also contribute to a vertical variation in the fracture density. When mineralogy plays a role in rock brittleness, calcite-rich lithofacies might enhance the fracability of matrix and lead to higher fracture density in the Upper Barnett Shale under the same deformation scenario.

When comparing with regional gas production and anisotropy intensity, not all of the production distribution can be explained by anisotropy intensity; this is reasonable because the gas production can be affected by multiple other factors such as operation methods, hydraulic fracturing design, small-scale reservoir heterogeneity which is introduced by sedimentary structures, organic richness, and paleotopography. Gas production can be used as one but not the only verification index for the anisotropy. In the other words, the anisotropy could not entirely associated with the natural fracture...
network when other geologic anisotropy is involved in small regions.

Conclusion

The azimuthal anisotropy analysis method turned out to be an efficient tool to visualize the natural fracture network below seismic resolution. High anisotropy can be used as an indicator for high occurrence (high density) of vertical, aligned fractures in HTI media.

Not only seismic amplitude, but also other seismic attributes can be used as input for anisotropy analysis such as the envelope, spectral peak frequency, and pre-stack P-wave impedance, which deliver similar results with high confidence. The envelope attribute has a better result quality and less patchy pattern, which can be considered as a more ideal candidate for anisotropy analysis in the future. Picking horizons on azimuthal seismic volumes separately and extracting the seismic attributes along these corresponding horizons can eliminate the VVAz effect, which ultimately enhances the accuracy of azimuthal anisotropy analysis.

In this study area, there are four anisotropy zones identified as zones A, B, C, and D. There is a general decreasing trend of anisotropy intensity downward to the base of the Barnett Shale in all four zones. Zones A, B, and D’s fractures are more associated with the deformation of the two nearby normal-strike slip faults. Zone C’s fractures are more related to the paleo stress field that occurred even earlier than the other three fracture zones.

The anisotropy analysis workflow proposed in this research not only provides an aerial interpretation of the natural fracture network but also a spatial variability of a fracture network throughout the formation. Vertical and aerial variability of anisotropy intensity and azimuth obtained from this workflow make it accessible to understand fracture development history and help determine the best landing zone for potential horizontal wells. Unlike the former natural fracture modeling at the reservoir scale, which assumes that natural fractures follow a general azimuth, this workflow proves that the fracture density, azimuth could vary greatly due to different deformation history in a small region, and this variation could lead to high uncertainty for the subsurface fracture model.

A regional production map verified the assumption that the natural fracture is the main source of anisotropy in the study area. Natural fracture occurrence shows an inverse relationship with gas production, which means the natural fractures are sealed and inhibiting production by forming a more complex network with hydraulic fractures. Future production in this area should avoid high natural fracture intensity zones to obtain the best production performance. However, for those fracture networks that are open and promoting production, this workflow can also predict the fracturing sweet spot effectively.

Acknowledgments

Thanks to Devon Energy for providing a license to their 3D wide-azimuth survey, well logs, and production data for use in research and education. The data were pre-stack time migrated by our former colleague, S. Guo. Thanks go to CGG geoscience solutions for licenses to the Hampson Russell inversion software and to Schlumberger for license to Petrel. This work was supported by the Foundation of State Laboratory of Shale Oil and Gas Enrichment Mechanism Effective Development and the Woodford Consortium at the University of Oklahoma Institute of Reservoir Characterization.

Data and materials availability

Data associated with this research are available and can be obtained by contacting the corresponding author.

References


Gray, F. D., and K. J. Head, 2000, Using 3D seismic to identify spatially variant fracture orientation in the Manderson field: SPE Rocky Mountain Regional/Low-Permeability Reservoirs Symposium and Exhibition.


Rüger, A., 2002, Reflection coefficients and azimuthal AVO analysis in anisotropic media, SEG.


Tsivkin, I., and V. Grechka, 2011, Seismology of azimuthally anisotropic media and seismic fracture characterization: SEG.


Jing Zhang received a Ph.D. (2019) in geology from the University of Oklahoma. Her research focuses on comprehensive unconventional reservoir characterization especially for the Woodford Shale in Oklahoma. Her research combines geologic interpretation of reservoir properties and mechanism of deposition. Another part of her research is to study natural fracture distribution patterns in shale using multiscale/multidisciplinary methods, which include outcrop, core, and seismic fracture characterization.

Jie Qi received a Ph.D. (2017) in geophysics from the University of Oklahoma, Norman. He was a postdoctoral research associate at the University of Oklahoma from 2017 to 2020. He is currently a research geophysicist at Geophysical Insights. His research interests include machine learning, pattern recognition, image processing, seismic attribute development and interpretation, and seismic facies analysis.

Kurt J. Marfurt received a Ph.D. (1978) in applied geophysics from Columbia University’s Henry Krumb School of Mines in New York, where he also taught as an assistant professor for four years. He joined the University of Oklahoma (OU) in 2007, where he serves as the Frank and Henrietta Schultz professor of geophysics within the ConocoPhillips School of Geology and Geophysics. He worked for 18 years in a wide range of research projects at Amoco’s Tulsa Research Center, after which he joined the University of Houston for eight years as a professor of geophysics and the director of the Allied Geophysics Lab. He has received the following recognitions: SEG best paper (for coherence), SEG best presentation (for seismic modeling), as a coauthor with Satinder Chopra for best SEG poster (for curvature) and best AAPG technical presentation, and as a coauthor with Roderick Perez-Altamar for best paper in Interpretation (on a resource play case study). He also served as the SEG/EAGE Distinguished Short Course Instructor for 2006 (on seismic attributes). In addition to teaching and research duties at OU, he leads short courses on attributes for SEG and AAPG. His primary research interests include the development and calibration of new seismic attributes to aid in seismic processing, seismic interpretation, and reservoir characterization. Recent work has focused on applying coherence, spectral decomposition, structure-oriented filtering, and volumetric curvature to mapping fractures and karst with a particular focus on resource plays.

Roger M. Slatt is the Gungoll family chair professor in petroleum geology and geophysics at the University of Oklahoma and director of the Institute of Reservoir Characterization in the Sarkeys Energy Center at OU. He has published approximately 150 articles and abstracts and is author/co-author/editor of six books on petroleum geology, reservoir geology, sequence stratigraphy, clastic depositional systems, geology of shale, and deepwater sedimentary processes. Dr. Slatt passed away in February 2020, and we would like to send our sincerest gratitude for his support to all his students and his contribution to academia and industry.