PSDM for unconventional reservoirs? A Niobrara Shale case study

Morgan P Brown*, Wave Imaging Technology Inc., Denver, CO (morgan@wvmgtk.com),
Joseph H. Higginbotham, Cosmin Macesanu, Oscar E. Ramirez, Wave Imaging Technology Inc., Houston, TX;
Dave List and Chris Lang, Fidelity E&P Company, Denver, CO

Summary

Unconventional resource plays currently absorb a significant proportion of onshore U.S. E&P budgets. The perceived simplicity and homogeneity of unconventional reservoirs explained their initial appeal to firms seeking to reduce “dry hole risk”. However, as inconsistent drilling results from many resource plays highlight, shale reservoirs are neither simple nor homogeneous. Used infrequently 5-10 years ago, drillers today commonly employ 3D seismic to improve horizontal well “geosteering”. Looking ahead, there is great interest in exploiting 3D seismic to delineate productive “sweet spots”. In particular, differential horizontal stress (from azimuthal anisotropy analysis) and elastic inversion for “brittleness” are paired to find optimal drill locations and wellbore orientation (Sena et al., 2011).

While prestack depth migration (PSDM) is commonly applied in “complex” plays such as the sub-salt Gulf of Mexico, it has been adopted in resource plays at a slow (but accelerating) pace. PSDM promises two major “structural” benefits over conventional time imaging:

- More accurate geologic dips between well control
- Crisper and better positioned view of faulting

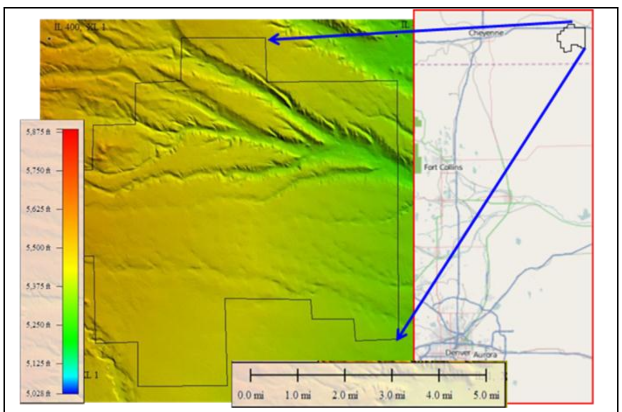

Figure 1: Burns Survey outline with topography (300 ft variation over the survey) and an inset showing the survey’s location relative to Cheyenne and Denver. The receiver patch was nearly square, with a nominal fold of 150.

Additionally, in areas that exhibit velocity complexity, seismic anisotropy, and dipping beds, PSDM can provide more accurate input for most attribute technologies.

We present a case study from a wide-azimuth 50 mi^2 (140 km^2) survey acquired in the Niobrara Shale (see Figure 1). While the study area exhibits mildly dipping beds, a significant shallow lateral velocity variation motivates the use of PSDM to correct event dips and improve the focusing of faults. Vertical mistie correction predicted the top Niobrara to within 4 feet on a new well, but we show enough variation in Thomsen δ to justify anisotropic PSDM.

Azimuthal velocity analysis using Wave Equation PSDM (WEM) azimuth angle gathers indicates a very weak level of overburden azimuthal anisotropy. However, we show that amplitude versus azimuth (AVAZ) may better measure differential horizontal stress in the target interval. Sonic scanner data from a recent well broadly confirms the magnitude of AVAZ response observed in the data.

PSDM Velocity Analysis

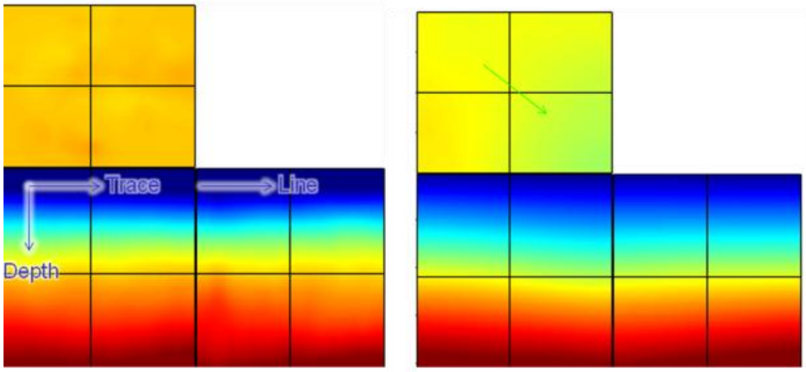

Figure 2: Starting velocity model (left), derived from time migration velocity analysis, versus final PSDM velocity model (right), derived from 8 iterations of WEM angle gather update. Notice on the depth slice (taken at 2,500 ft) how the final velocity model has a significant lateral variation.

Rigorous, iterative velocity update proves key to the success of depth migration. We began with an interval velocity derived from prestack time migration (PSTM). We utilized a WEM algorithm with incidence angle gathers (Macesanu et al., 2010) to update the velocity model by vertically backprojecting measured errors. Figure 2 highlights a comparison between the starting velocity and the final velocity. Notice how we resolved a significant (5%) lateral variation in shallow velocity, which is believed to be caused by a thickening alluvial wedge.

Depth Migration vs. Time Migration

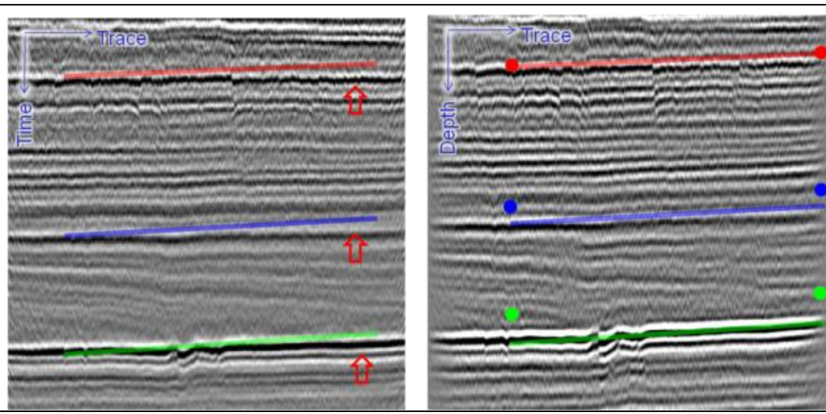

Figure 3: PSTM image (left) versus final PSDM image (right). The PSDM image is overlaid with well tops from three wells (dots). The lines on the right panel connect the well tops and are shifted down to match the PSDM seismic horizon. The same lines are projected onto the PSTM image. The dip of the PSDM image is far more accurate than the corresponding PSTM dips.

Figure 3 compares one inline from the final WEM image to the PSTM image. Well tops are shown on the PSDM image – they don't tie the seismic image due to anisotropy (discussed later), yet the well-derived dips match the PSDM-derived dips very well. In fact, a simple vertical mistie correction on the PSDM image predicted the top Niobrara (green) to within 4 feet on a new well. Due to shallow velocity variation (Figure 2), the PSTM dips do not match the geologic dip – this could play havoc with geosteering, unless dense well control was available (it was not in this example).

Figure 4 compares the final PSDM image to the PSTM image. The depth images have been converted to time to a) ensure a direct comparison, and b) to highlight that the frequency content of the depth image is comparable to that of the time image. Two previously invisible faults, each with a throw of about 15 feet, were interpreted along an upcoming well path. In general, PSDM yields improved spatial resolution of fault truncations.

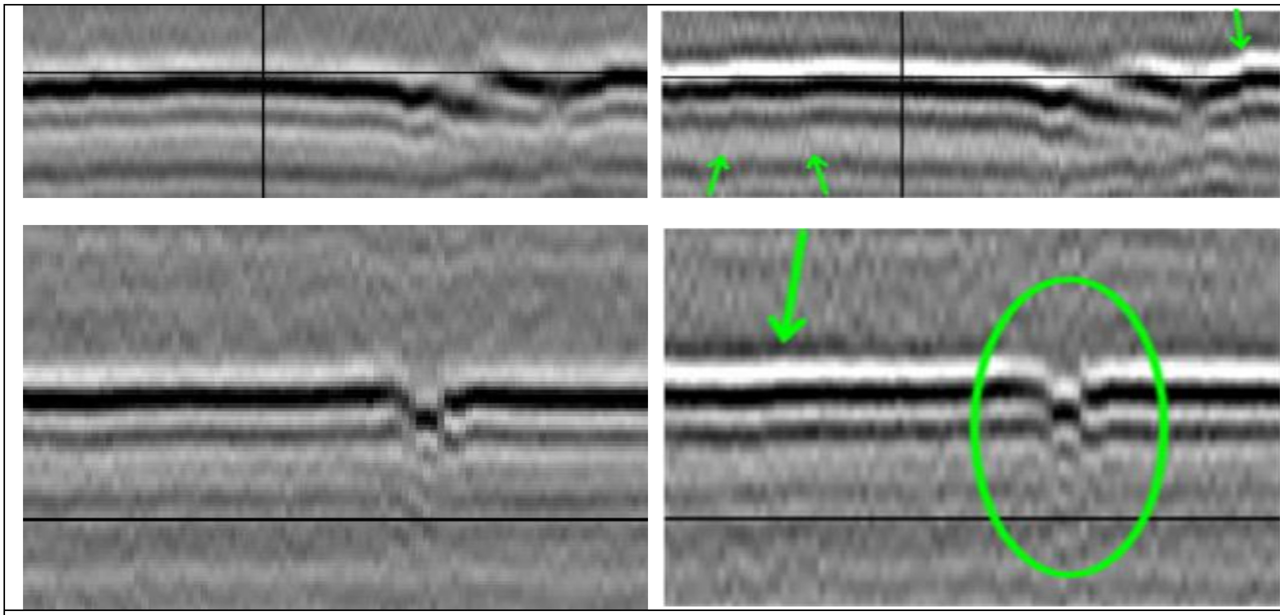

Figure 4: PSTM images (left panels) versus PSDM images (right panels), converted to time. The arrows and oval illustrate sharper fault truncations on the PSDM images; some faults have less than 15 ft of throw.

Vertical Anisotropy

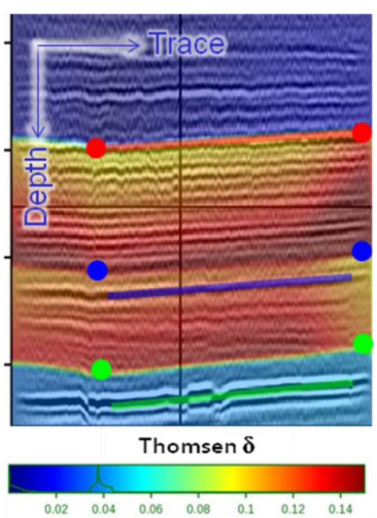

Figure 5: Thomsen δ field overlaying seismic line. The colorbar varies from 0 to 0.15. Above the top Pierre Shale (red top), the earth is effectively isotropic. Within the Pierre Shale, we measure δ in the 0.08 to 0.15 range. Below the top Niobrara (green top), we have no constraint on the deeper anisotropy.

On Figure 3, notice how the isotropic PSDM image does not tie the well tops. Shaly sediments exhibiting vertical transverse isotropy (VTI) are the culprit. The Thomsen δ parameter primarily controls depthing. The anellipticity parameter η, which is $\varepsilon-\delta$, causes so-called "hockey sticks" at far offsets, and can be measured with time migrated data. δ can only be measured with depth migrated data.

If δ is constant-valued throughout the volume, then we would expect misties increasing with depth. In other words, each top would be too deep by a fixed percentage. However, in Figure 3, notice that the red top ties the seismic very well, while the green top is far shallower than the corresponding seismic horizon. This implies that the δ field has strong vertical variations. Figure 5 illustrates the δ field estimated by a 3D inversion of well-seismic misties. While the shallow section, from 0 to about 4,000 ft depth is effectively isotropic, the Pierre Shale, which overlays the Niobrara, exhibits high anisotropy.

At present, we have not applied a VTI PSDM workflow to the Burns survey. After using the vertical velocity volume (derived by scaling the migration velocity in Figure 3 by the δ field in Figure 5) to vertically warp the image to well control, we found that the predicted Niobrara depth for a new vertical well was accurate to 4 feet. However, given anisotropy's tendency to "move" faults laterally, we may decide to perform anisotropic PSDM in order to optimize fault locations for field development.

Seismic Attributes

The detection of “sweet spots” in resource plays has enormous economic potential. Rock attributes that may correlate with high productivity include natural fractures, organic content, and “brittleness”, or the ability of a shale layer to propagate induced hydraulic fractures (“fracs”). Moreover, to optimize the efficacy of a frac job, an optimal well plan should account for the maximum horizontal stress direction. Horizontal stress often varies significantly between wells (Tingay et al. (2005)).

Modern 3D seismic data shows great potential in resolving both elastic rock properties and natural fracture orientation/intensity, particularly when the data are acquired with a wide azimuth distribution, long (enough) offsets, high fold, and high frequency content. The Burns survey is an ideal candidate for such analyses.

PSDM offers some very tangible theoretical benefits over time migration for attributes. First, in the presence of lateral velocity variation, time migration laterally mispositions structures and amplitudes. Secondly, most attribute calculations require seismic data versus angle, but PSTM images are generally organized in terms of surface offset and azimuth. Lateral velocity variation and/or geologic dip make it impossible to unambiguously convert from offset/surface azimuth to incidence angle/reflection azimuth. We employed Macesanu et al’s (2010) efficient technique to compute dense azimuth/incidence angle WEM gathers.

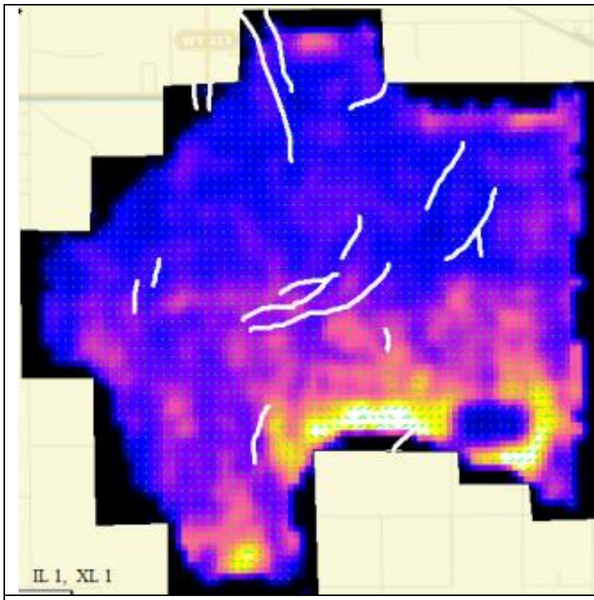

Figure 6: Fracture map made on top Niobrara horizon. Colors represent relative fracture magnitude. Thick white lines represent fault cuts. Small green lines (too small to view here) represent fracture orientation. The map was obtained by analyzing PSDM amplitude variations versus azimuth. We notice a large range of apparent azimuthal anisotropy – 0 to 70% azimuthal amplitude variation.

In a medium exhibiting horizontal transverse isotropy (HTI), ideally caused by vertical fractures, seismic traveltimes will vary sinusoidally versus azimuth, for a fixed incidence angle. We computed 3D volumes of “fracture” orientation and relative magnitude by scanning all gathers for this sinusoidal azimuthal signature. So-called “HTI Analysis” revealed weak spatial variations in fracture magnitude – the maximum observed magnitude at the Niobrara level was only 0.3%, barely at the threshold of detection. Others have reached the same conclusions (e.g., Gardner and Donoho (2012)).

However, the Niobrara interval itself is heavily faulted, and we observed fractures in FMI data. Azimuthal anisotropy analysis measures a bulk overburden effect. Amplitude versus azimuth (AVAZ) methods may prove more fruitful because they vary contrasts in HTI parameters. Ruger (1997) quantified a relationship between HTI fracture orientation/magnitude and the AVA slope parameter versus azimuth.

Figure 6 illustrates a fracture map derived from AVAZ analysis. This map displays significantly spatial variation, with relative azimuthal amplitude variations ranging from 0 to 70%. Sonic scanner data from a recent well measured a 3% shear wave splitting parameter, which when plugged into Ruger’s equations, predicts a 40-50% variation in azimuthal amplitude. Unfortunately, an inherent 90^o ambiguity with regard to resolved fracture orientation hampers AVAZ method in practice (Goodway et al., 2010).

Conclusions

We presented a strong structural rationale for performing an advanced PSDM workflow on the Burns survey in southeast Wyoming. We measured a 5% lateral variation in shallow velocity, which created a dip reversal on time migrated data. PSDM corrected the false time structure and also produced a clearer image of very small faults. Specifically, we detected two previously unseen faults with ~15 ft of throw which presented a serious drilling challenge, since the Niobrara zone is only 20 ft thick.

Significant VTI anisotropy was present, particularly in the Pierre Shale overlying the Niobrara. Since vertical correction for the anisotropy-caused misties sufficed to produce an accurate horizon map, we elected not to initially proceed with a VTI PSDM workflow. A failure to do this may position faults incorrectly.

Azimuthal anisotropy between the surface and Niobrara was very weak (0.1-0.3% total depth error versus azimuth). However, AVAZ analysis may prove more fruitful, as it is targeted to the Niobrara. We observe up to 70% variation of PSDM amplitudes versus azimuth. While large, these azimuthal amplitude variations are consistent with sonic scanner data from a recent well.

Acknowledgements

The authors thank the management of Fidelity E&P Company, as well as Fidelity's partner, Itochu Oil, for permission to show the data examples presented herein.

References

Seismic petrophysics and isotropic-anisotropic AVO methods for unconventional gas exploration, Bill Goodway, Marco Perez, John Varsek, and Christian Abaco, The Leading Edge 29, 1500-1508 (2010)

Angle decomposition for one-way wave equation migration, Cosmin Macesanu, Joseph H. Higginbotham, and Morgan P. Brown, SEG Expanded Abstracts 29, 3242-3246 (2010)

P-wave reflection coefficients for transversely isotropic models with vertical and horizontal axis of symmetry, Andreas Rüger, Geophysics 62, 713-722 (1997)

Seismic reservoir characterization in resource shale plays: "Sweet spot" discrimination and optimization of horizontal well placement, Arcangelo Sena, Gabino Castillo, Kevin Chesser, Simon Voisey, Jorge Estrada, Juan Carcuz, Emilio Carmona, and Robert V. Schneider, SEG Expanded Abstracts 30, 1744-1748 (2011)

"Understanding tectonic stress in the oil patch: The World Stress Map Project", Tingay et al., December, 2005 The Leading Edge.

A Multidisciplinary evaluation of the Niobrara formation, Morgan/Weld Counties, D-J Basin, Eric Gardner and Dan Donoho, 18th Annual 3-D Seismic Symposium, 2012