B031

Advanced Imaging and Inversion for Unconventional Resource Plays

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SUMMARY

With a typical 3350m lateral well with more than 30 completion stages costing $8 million and upwards (upstreamonline.com 2011), the infill plan dramatically impacts long-term economics of the program. For very little relative additional cost, 3D seismic technology can be effectively utilized to reduce the risk of drilling costs overrun and maximise ultimate recovery from the field. The key is processing the seismic data specifically for these types of plays without taking shortcuts due to perceived time and cost constraints. We present a case study from the Bakken shale play in North Dakota, U.S., where advanced imaging and inversion techniques unlock the true predictive power of 3D seismic methodology for optimal development of unconventional resource plays.
Introduction

Unconventional tight shale oil and gas plays have recently become major targets for exploration companies. What started in the United States as a new way to exploit these plays using extended horizontal drilling and hydraulic fracturing technologies has now expanded worldwide. Current development of these plays is a statistical process where evenly laid out drilling locations allow a company to hold land leases and ensure a projected return on investment based on early initial and cumulative production numbers from neighbouring wells. The challenge then becomes the design of the infill drilling program and how best to maximise the ultimate recovery of resource from each field in a timely fashion.

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Theory and method

Land 3D seismic data are normally acquired with multiple azimuth directions between source and receiver positions. Advantages of multiazimuth seismic acquisition have been well documented within the industry (Kapoor and Woodward 2008). Multiazimuth seismic data not only enables superior imaging, but if the azimuthal information is carried correctly through all imaging steps, multiazimuth inversion techniques utilising both residual traveltimes and amplitudes can be effectively used for reservoir property description. However, the quality and effectiveness of the derived attributes are directly related to the quality of the seismic imaging used in the inversion (Johnson and Dorsey 2010). Overburden heterogeneity, transverse isotropy (TI) and azimuthal anisotropy must be taken into account when performing advanced imaging processes on land 3D seismic data. Although high-frequency static corrections still play a part in correcting for surface-consistent near-surface effects, they must be combined with a very accurate earth model and depth migration to achieve the kind of resolution required for effective inversion mapping of deep reservoir properties.

All available a priori data must also be included in the building of the earth model used for imaging. This allows the model to be tied into the geology by means of borehole data and interpretations performed by the geological specialists for the area. The net result is, during the imaging step, the seismic structure and amplitudes are mapped much more accurately than with post-imaging calibration methods. Amplitudes in particular are very highly impacted by TI effects (Thomsen 2002) and any amplitude versus angle inversion work will benefit from advanced imaging that properly corrects for this.

The multiazimuth information in the seismic data should be carried through the imaging step to allow for advanced prestack inversion of traveltimes and amplitudes. We migrate the data in offset vector tile (OVT) format to achieve this objective. The OVT data also allow for very effective multiazimuth tomography permitting accurate modeling of overburden heterogeneity for TI anisotropy properties. Tomography allows for simultaneous updates to velocity and Thomsen’s delta and epsilon because it employs tight constraints to the well data formation tops. This ensures accurate well ties, as shown in Figure 1, and optimal focussing through the stacking of flat gathers. Our version of advanced imaging achieves high image fidelity (flat gathers) and optimal seismic to formation ties (structural integrity) by means of the imaging step, with very little if any, post-imaging calibration required. Inversion processes can now be performed with greater confidence in the accuracy of the results.
Fitted elliptical anisotropy from traveltimes (FEATT)

After completing the advanced earth modeling and imaging process as described above, we start by inverting traveltine differences versus azimuth using a workflow called FEATT. We now have more confidence that the residual traveltine differences observed on the common-image-point offset azimuth gathers are related to azimuthal anisotropy as opposed to overburden effects as shown in Figure 2.

**Figure 1** Results of a reservoir level (~2400m SS) seismic surface tie to the available well control, both before and after tomography updates to Vp and TI parameters, plus remigration. The purple coloured trench in the upper left portion of the display is associated with near-surface velocity variations that get modeled using three-term tomography. The tightening of the well tie histogram provides more confidence in the depth of the interpreted surface after advanced imaging.

**Figure 2** Two OVT gathers sorted by 3D azimuth within increasing offset ranges. Display A is a conventionally migrated OVT; whereas, B uses advanced imaging discussed in this paper. Notice how the sinusoidal residual traveltimes were reduced from A to B after the overburden effects were removed in the imaging. The residual traveltimes left in B can now be inverted as related to azimuthal anisotropy.
After converting the data to time domain, we block the picked residual traveltimes into discrete layers and invert into fast and slow interval velocities (vfast, vslow) by fitting them to an ellipse. The azimuth of the vfast velocity is also output during the process. This inversion is very sensitive to the small phase and amplitude distortions associated with the land acquisition footprint as shown in Figure 3. After removal of these acquisition effects using a k-notch filter, a distinct lineament-style pattern can be observed at the reservoir level. This may be associated with the tectonic stress that the basin experienced at one point in its history.

![Figure 3](image)

**Figure 3** Azimuth of the derived fast velocity by the FEATT inversion at approximately 2400 m subsea both before A and after B acquisition footprint removal. Notice how sensitive the inversion is and how the true azimuthal signal can be masked without the acquisition footprint removal process. Also notice the lineament-type pattern associated with some of the common azimuth orientations of the fast velocity.

**Simultaneous azimuthal amplitude variation with angle elastic inversion (AVOAZ)**

The preservation of amplitude and azimuthal information in the imaged OVT seismic data enables the implementation of a simultaneous prestack seismic inversion workflow to estimate attributes of shear-wave anisotropy. The method we use is an extension of isotropic simultaneous inversion with global optimization based on simulated annealing (Rasmussen 2004), incorporating an approximation to the elastic anisotropic Zoepritz equations (Psencik and Martins 2001). We calibrate the angular (AVO) and anisotropic azimuthal (AVAZ) reflectivity variation to the recorded surface seismic OVT data by utilizing measured dipole sonic, compressional sonic and density well log data using a deterministic wavelet estimation methodology. We perform simultaneous inversion of all the azimuthally sectored angle-stack data to generate volume estimates of acoustic impedance, density, fast and slow shear impedance, and an orientation estimate of the fast shear azimuth. In combination, the fast shear azimuth estimate with a derived attribute, slow/fast shear impedance ratio, highlights anisotropic intervals and layers that are shown to have a high correlation to measured borehole anisotropy. This inversion method also has the benefit of improved estimates of acoustic impedance and density as shown in Figure 4, because azimuthally sectored angle stack data typically has less smearing due to anisotropy effects, compared to a full-azimuth angle stack. This presents the potential for more accurate inversion-derived lithology and fluids prediction.
Figure 4 Acoustic impedance and density results of the AVOAZ inversion through to the reservoir level for a single well location.

Conclusions

We defined a methodology for advanced imaging of 3D surface seismic data and have shown how important it is to perform this step prior to inversion processes that use prestack traveltime and amplitude information. We also showed how these two inversion processes are complimentary and provide important information about the rock properties within a Bakken shale unconventional resource play. We can now proceed to produce crossplots between inverted seismic attributes and general production figures from existing lateral wells and examine the relationships between the two. The inverted seismic attributes have the potential to be a powerful predictor of future well performance and can be used in the planning and execution of the continuing infill well program.

References


