Imaging and characterization of a shale reservoir onshore Poland, using full-azimuth seismic depth imaging

Henryk Kowalski[1], Piotr Godlewski[1], Wojciech Kobusinski[1], Jakub Makarewicz[1], Michal Podolak[1*], Aldona Nowicka[2], Zbigniew Mikolajewski[2], David Chase[3], Raanan Dafni[3], Anat Canning[3] and Zvi Koren[3] discuss the application of a new seismic data imaging method: full-azimuth angle domain depth imaging.

The exploration and development of shale plays in Europe show that the 'statistical drilling' approach used in some basins in recent years cannot be extended to areas where local stress in rocks or fracture distribution varies both laterally and in depth. Moreover, drilling and fracturing practices confirm the presence of local geobodies resistant to hydraulic fracturing.

This paper discusses the application of a new seismic data imaging method *full-azimuth angle domain depth imaging*, which is particularly useful when working with rich-azimuth seismic data. This innovative technology was applied to meet the challenges of imaging in a complex geological environment, and is a pioneering solution in Polish shale gas geology.

Results obtained in the study from the analysis of seismic data were in line with results of the geologic and geophysical analysis of the borehole data, as well as with information from microseismic monitoring of fracturing treatment. The technology delivered high-quality images of the reservoir and geomechanical characterization of rocks with the precision needed to steer horizontal drilling, detect sweet spots, and locate geobodies resistant to fracturing.

The seismic imaging workflow is based on software specifically developed to meet the challenges of shale gas seismic (Koren and Ravve, 2011, Koren et al., 2013, Canning and Malkin, 2013). One of the main advantages of this approach is that it works directly in the local angle domain (LAD) instead of the surface offset/azimuth domain. The use of in situ azimuth in LAD, visualized together with dedicated seismic attributes, provides information about the intensity and orientation of geological stress/fracture systems. Geothermal prospecting and seismic imaging of conventional hydrocarbon plays can also profit from this method. This technique is particularly suitable for Poland, where conventional seismic migration of reflections from geology covered by a complex overburden has frequently resulted in improper imaging.

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Geologic setting

A rich-azimuth 3D seismic survey was acquired in Northern Poland, in the Baltic Basin margin, where Silurian and Ordovician gas- and oil-bearing shales are prospective targets, around 3 km b.s.l. (Figure1). Pre-existing stress and fractures were expected to form an azimuthal anisotropy signature in seismic data. Near square, active recording spread was applied to make azimuthal analyses reliable. Nominal stacking fold 165, max. offset of 4285 m, CMP bin size 20 x 20 m, and a fairly homogeneous azimuth-offset distribution led to the assumption that the acquisition geometry was approximately full-azimuth. Data regularization was applied directly in the local angle domain by dedicated *full-azimuth angle domain depth imaging*, optimizing reliability of the azimuthal distribution of seismic events. The applied software system does not require any preliminary trace interpolation.

In the surveyed area, located in the 'zone of interest' marked in Figure 1A, the tectonics are smooth and horizontal, so VTI approximation was sufficient to account for polar anisotropy. TTI was not taken into account. Main target reflections from Ordovician formations are indicated by the blue arrow in Figure 1C. The geologic structure of the area can be seen in Figure 1D, through maps of the main seismic horizons, top to bottom: Zechstein base, internal Silurian reflection showing the internal structure of the Silurian complex, Ordovician reflection – a complex fault system directly related to the crystalline basement. Pre-Cambrian reflection indicates that the basement is most intensively related to block tectonics.

Figure 2 provides an additional view of the investigated geology. The overburden with the Zechstein interval and with anhydrite barriers interlaced with salt structures causes severe deformations to seismic images of the deeper horizons. Fairly large vertical and horizontal changes in the velocity

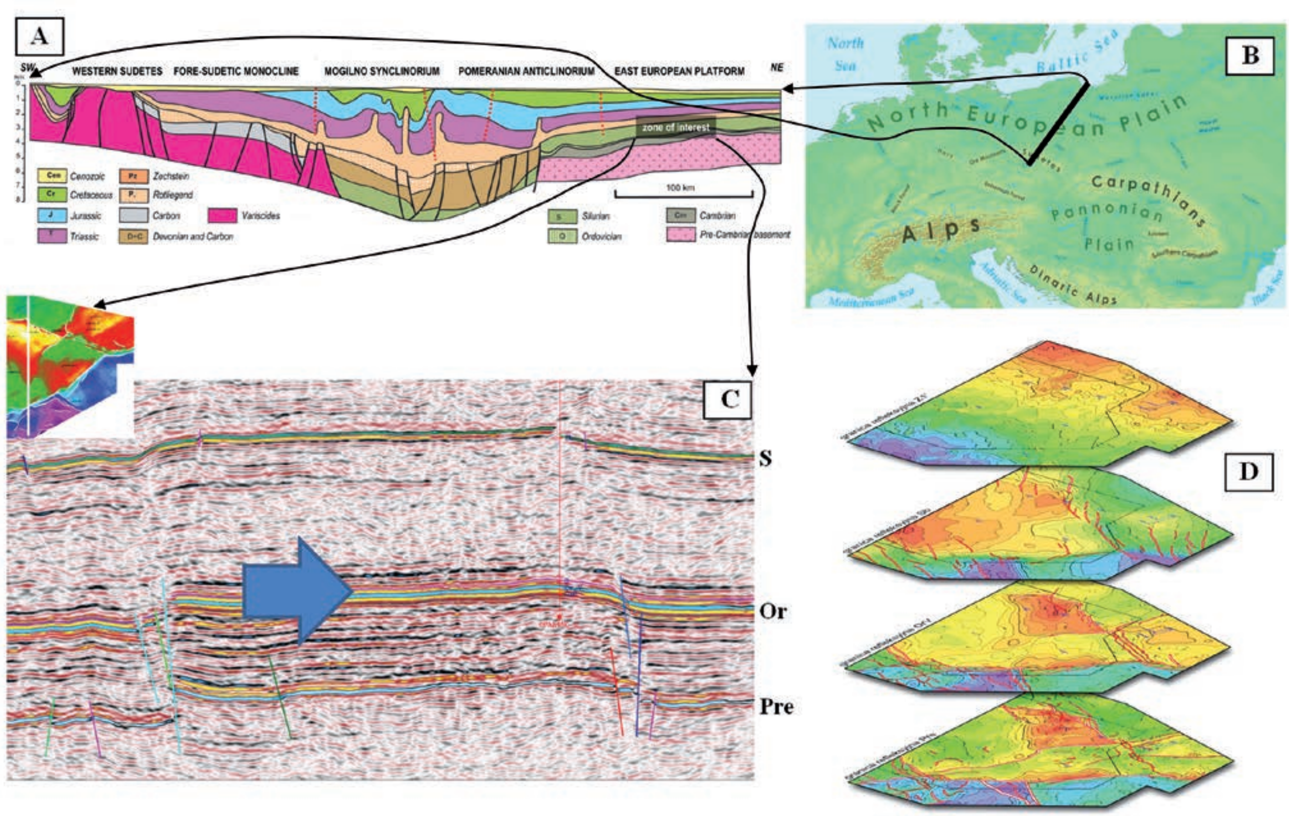

Figure 1 Survey area. Figure 1C shows a sample vertical section of the area; a depth map of the target horizon is in the top-left corner of Figure 1C. Regional cross-section in Figure 1A is after Karnkowski, 2008 and Zelazniewicz et al., 2011.

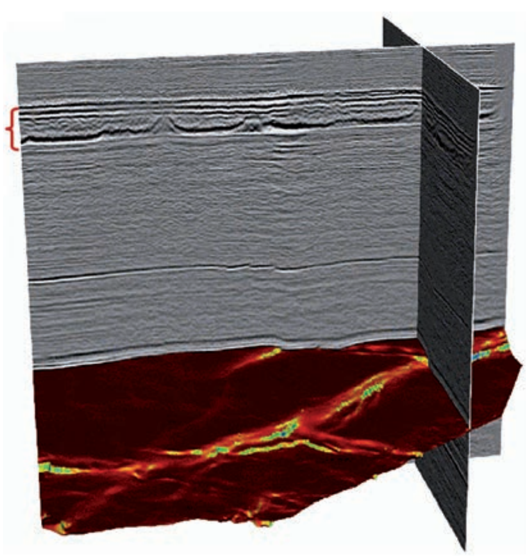

Figure 2 The complex Zechstein model causes deformations of the target Ordovician horizon. The brown brace points at the Zechstein interval with anhydrite barriers interlaced with salt structures.

model comprise focusing and defocusing phenomena. They strongly impact structural and amplitude maps of deeper targets. In such complex tectonics, only precise, advanced depth imaging solves the problem. It turns out that software dedicated to seismic imaging in such areas solves both the tasks of model building and migration in orthorhombic (VTI + HTI) media for unconventional targets, and in conventional VTI media shadowed by complex overburden.

Workflow developed for the project

The project was targeted at characterizing potential shale gas resources: the contents of organic matter and the distribution of geomechanical properties of target formations – in order to optimize production. A dedicated methodology was designed, comprising the acquisition and analysis of different geological and geophysical data. The unconventional characterization workflow (seen in Figure 3) included formation evaluation, seismic data analysis, and construction of a geomechanic 3D model.

Measurements in boreholes are essential for effective prospecting. They provide key data to calibrate indirect measurements, especially seismic results: VTI and HTI anisotropy parameters, and estimates of rock elastic parameters.

While a comparison between seismic and the results of other pieces of this workflow are important to mention, the focus of this paper is on application of the novel depth imaging of 3D rich-azimuth land seismic data. The software used for seismic imaging is called EarthStudy 360.

Using this software, it is possible to build an anisotropic model updated with full-azimuth tomography, account for

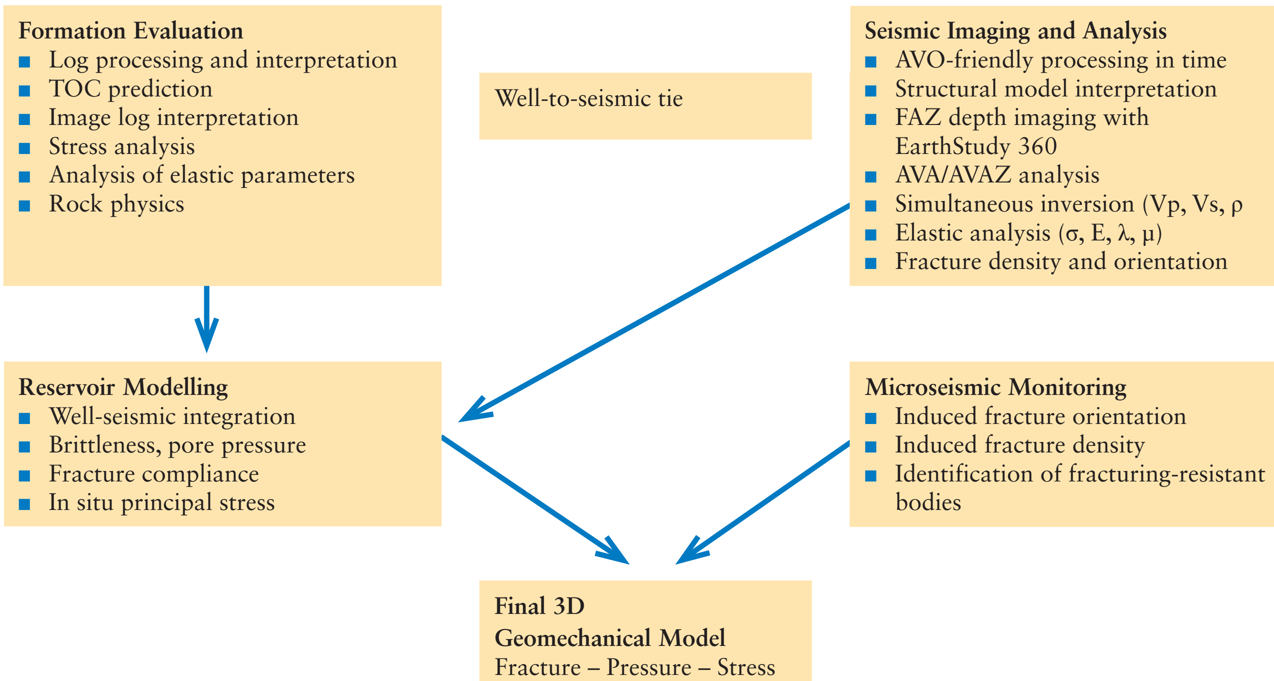

Figure 3 *Integrated workflow designed to characterize the unconventional play.*

different amplitude losses, properly handle illumination corrections including azimuthal factors, and extract continuity components from seismic data – a byproduct of diffraction imaging. An important feature is the precise conversion from effective to interval attributes performed in the depth-variant LAD with in situ azimuth.

The software also provides an environment for interpretive AVA and AVAZ analysis of data imaged using the full-azimuth prestack depth migration, with its built-in Common Reflection Angle Migration (CRAM) algorithm.

Formation evaluation

The interpretation of well data (Figure 4) shows moderate-intensity depth-variant azimuthal anisotropy. An azimuthal rose diagram (right bottom corner) shows a local dominant orientation of azimuthal anisotropy, which aligns with the seismic estimate of the location of the vertical well (Figure 14).

Many measurements were logged in the wells, the most important of which were obtained using a crossed-dipole sonic tool and electrical micro-imager (XRMI). Data processing results indicate anisotropy in some parts of the Silurian and Ordovician sections. The general direction of anisotropy confirms the direction estimated from seismic in the most interesting zone. A comparison between WaveSonic results and electrical imager data (XRMI) indicates that anisotropy is predominantly related to the presence of fractures; however, it may also be caused by carbonate or pyrite concretions inside shales.

A detailed analysis of azimuthal anisotropy orientation in well data suggests that it is depth-variant, and a vertical resolution of 5-6 m is needed to distinguish single, stable intervals. That is below the present seismic resolution estimated from $\lambda/4$ formula. However, the positive correlation between seismic- and well-predicted HTI anisotropy indicates that seismic averaging is acceptable.

Method of seismic imaging

In the preparation of input data, before beginning full-azimuth depth imaging, a series of time domain preprocessing steps were performed: wavelet processing was applied; surface-consistent statics and amplitudes were solved except for spherical divergence, which was compensated for in depth imaging; noise and especially multiples were eliminated; and diffractions were preserved. No prerequisite trace interpolation was applied. Special care was taken to make the time-domain processing AVO-friendly, meaning:

- A surface-consistent amplitude procedure compensated for source and receiver conditions and for LVL impact. Illumination irregularities, another type of overburden impact on amplitudes measured at target horizons, were not touched during pre-processing, as that job is built into EarthStudy 360.
- Wavelet processing provided a stable wavelet, and did not modify amplitude relations.
- The distribution of amplitude vs azimuth was preserved. This was enabled by solving five-component equation systems (known as 5D).

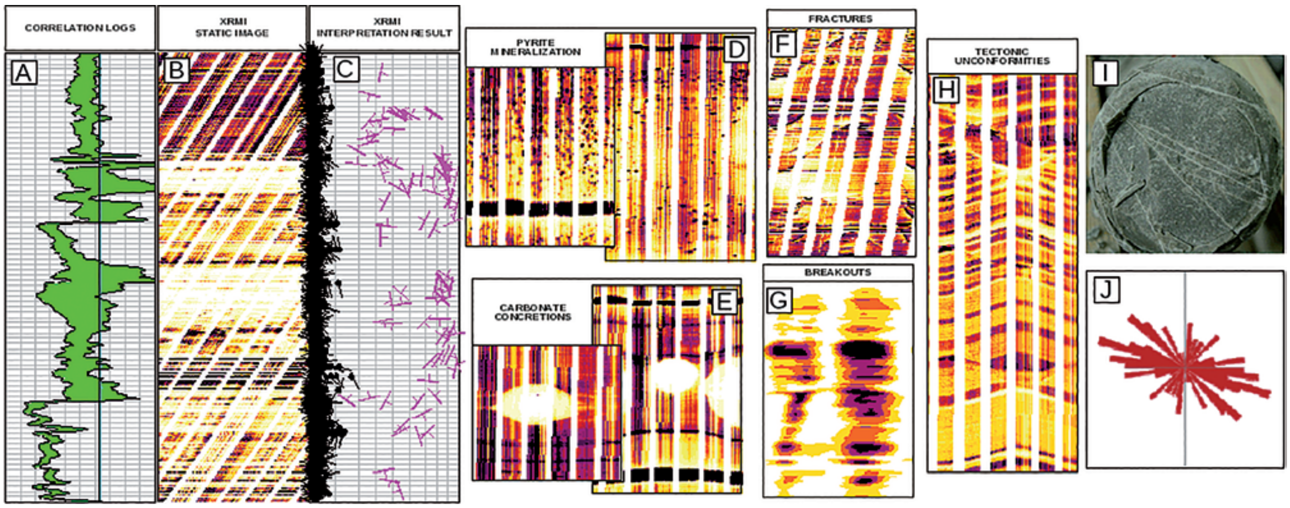

Figure 4 *Sample of direct images of fractures recorded with XRMI imager (panels B to H): D – pyrite, F, H – fractures, E – concretions, G – breakouts. In panel I - the core slice with natural fractures is displayed. Panel J shows a rose diagram of acoustic anisotropy in the target interval.*

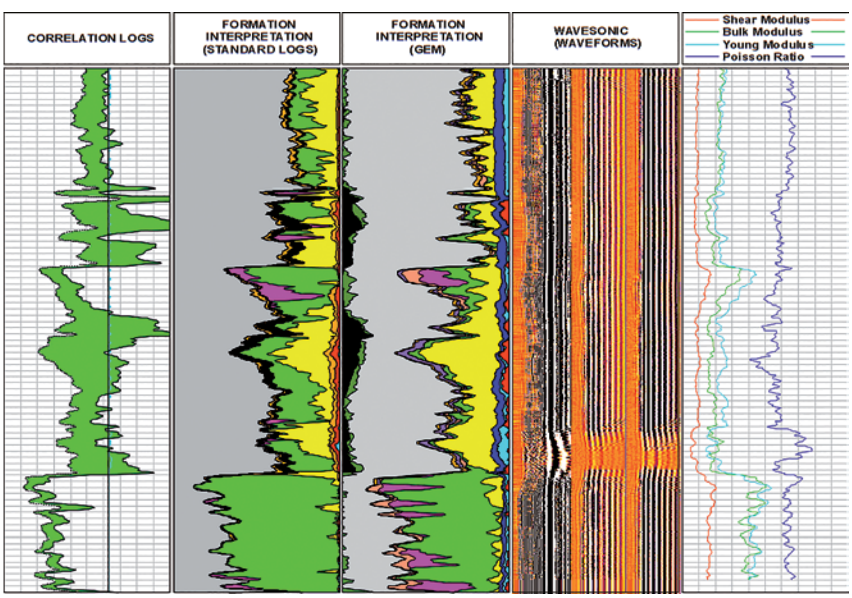

Figure 5 *Sample of the final results of litho-facial analysis of the reservoir interval, based on standard measurements and GEM tool. Shale contents, porosity, hydrocarbon contents, and TOC (from the Passey method) were estimated. The two rightmost panels come from the cross-dipole sonic tool.*

The first step in the depth imaging workflow was to estimate and compensate for polar anisotropy (VTI), a prerequisite for estimating azimuthal anisotropy parameters. Estimating the VTI model (V, ε, δ) involved the application of full-azimuth tomography to separate velocity heterogeneities from azimuthal anisotropy. This was important for building a reliable background model of the overburden, and ensured a consistent estimation of azimuthally-dependent phenomena at target. The accuracy of the VTI model was confirmed when new drilling was completed, where the seismic-to-well ties reached an accuracy of ± 3 m.

To meet the challenges of high precision, conventional seismic imaging in depth was replaced by the new software package dedicated to full-azimuth, angle domain depth imaging. This is actually a double-angle domain: reflection angles and azimuths. The surface azimuth, used in isotropic imaging, was replaced with a depth-variant local azimuth. The interval velocity model of the subsurface used in isotropic PreSDM was replaced by a VTI/HTI model. Effective azimuthally-varying residual moveouts measured along the local angle (LAD) gathers were transformed into local azimuthal anisotropic parameters using a generalized Dix-type method (Koren and Ravve, 2013).

The proposed full-azimuth depth imaging workflow offers numerous advantages, including:

- Wavelet stretch compensation in angle domain, enabling the use of long offsets.
- Illumination compensation, which minimized the impact of acquisition, complex overburden, and velocity model on amplitude distribution.

- Full-azimuth tomography, which separated heterogeneities from azimuthal anisotropy, thereby allowing proper correction for overburden.
- Transformation of the effective, azimuthally varying residual moveouts measured along LAD depth gathers into local (interval) anisotropic velocity parameters.
- Decomposition of the seismic wavefield into specular and diffraction components. This enhanced both structural continuity and small-scale discontinuities (faults or cracks).

All of these features revealed details in the subsurface of unconventional resources, and enabled better analysis of the azimuthal anisotropic effects on stress/fracture environments. The idea of in situ angle coordinates (LAD) is explained in Koren et al., 2011. The possibility for in situ expression of spatial relations between analyzed seismic events brings high precision to imaging. The local system of coordinates along seismic rays propagating through geological models is positioned according to changes in the model.

In full-azimuth seismic depth imaging, (x,y) coordinates of Kirchhoff migration are replaced with (θ, ϕ) – opening angle and angle of azimuth – coordinates directly involved in geomechanical analysis of seismic data. The opening angle and angle of azimuth are the basis of common reflection angle migration, generalized to full-azimuth seismic (after Koren and Ravve, 2010).

The workflow of the multi-attribute model building in depth, with its core: common reflection angle migration (CRAM – ES360 Imager) and full azimuth tomography can be found in Kobusinski, 2014.

Parameters describing the propagation history of the seismic wavefield are integrated along the path of each ray through a given earth model. Several attributes are taken into account to compensate for propagation through the model. Hit counts, illumination expressed in density of rays in a given elementary voxel, spherical divergence, and transmission effects are compensated for with ray tracing. Figure 6 shows the interactive control and analysis of illumination under conditions of real seismic spread.

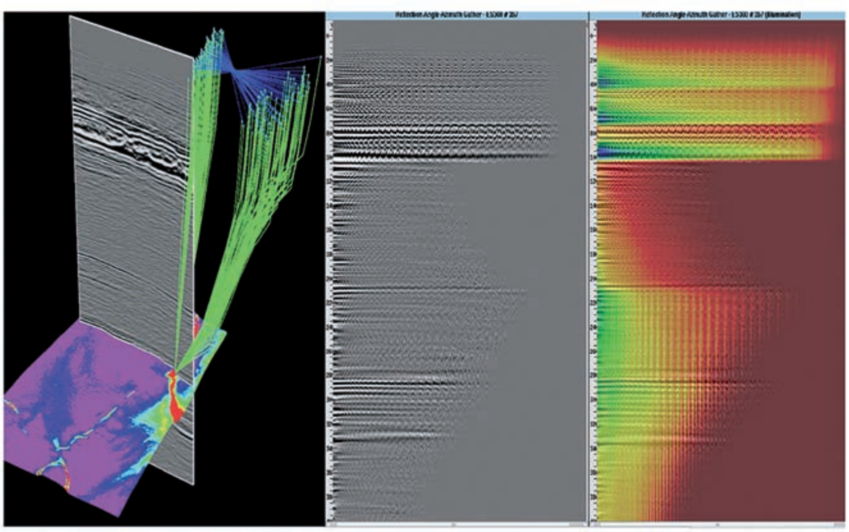

Figure 6 *Compensation for irregular illumination. Detailed interactive analysis of rays and their attributes. Ray fan filtered with real acquisition geometry is investigated (A). Samples of seismic CRP gather (B) and CRP gather with illumination in colour (C).*

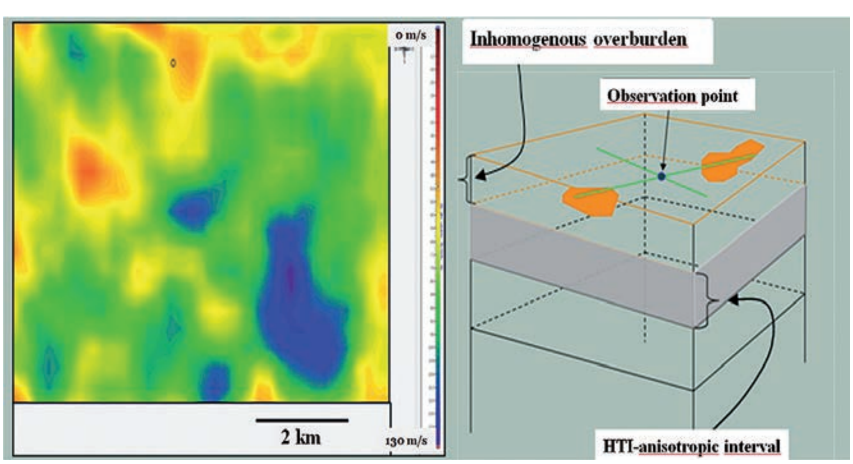

Figure 7 *Full-azimuth tomography: model of overburden heterogeneities (horizontal slice seen on the left) was identified and separated from azimuthal anisotropy. The right side of the figure shows how velocity heterogeneities can be mistaken for velocity azimuthal anisotropy.*

Another new option enabled by rich-azimuth prestack depth imaging in the local angle domain is full-azimuth tomography. This separates intrinsic azimuthal anisotropy from bodies, revealing velocity heterogeneity in overburden. That concept and an example of results obtained from full-azimuth tomography are displayed in Figure 7. Irregularities in the shallow velocity model seen at the left of Figure 7, once not accounted for properly, can cause lateral mis-positioning of mapped attributes in some areas of the investigated type.

Prestack depth migration not only results in a better image of Zechstein in Figure 8. It also means that the upper section of the model is correct. It then correctly guides seismic rays going down, and it ensures a correct image of the underlying sediments. The proof is sampled in Figure 9. Indeed, Ordovician and Precambrian reflections become well focused when switching from PreSTM to EarthStudy 360 PreSDM.

The conclusion is that full-azimuth prestack depth migration in local angle domain is the right seismic imaging for precise azimuthal analysis, especially in areas of moderate HTI anisotropy. The full-azimuth model is six-parameter: (V, ε, δ, $\alpha_{\text{slow local}}$, $\Delta\alpha$, ϕ) plus structural dip and depth maps of horizons.

Furthermore, a comparison was made between maps of HTI anisotropy based on two approaches: PreSTM followed by azimuth sectors, and FAZ PreSDM in angle domain equipped with built-in full-azimuth tomography and two azimuthal analysis options: AVAZ and VVAZ. The result can be seen in Figure 10.

When a model is HTI anisotropic, changes in the local system of coordinates include azimuthal rotation. For conversion of effective (averaged from free surface to current depth position) attributes into their interval counterparts, a generalized Dix-based approach was used (Koren and Rave, 2014).

Elastic interval attributes are necessary for the geomechanical characterization of rocks. In the case of unconventional seismic imaging for shale gas or for geothermal purposes, stress and fractures in rocks cause azimuthal anisotropic seismic-measured attributes. In such a case, the generalized approach of converting effective parameters into interval parameters is essential.

Inspection of the interval map in Figure 11C reveals that evidence of azimuthal anisotropy and of possible fractures is confined to certain areas. It becomes clear that some spots

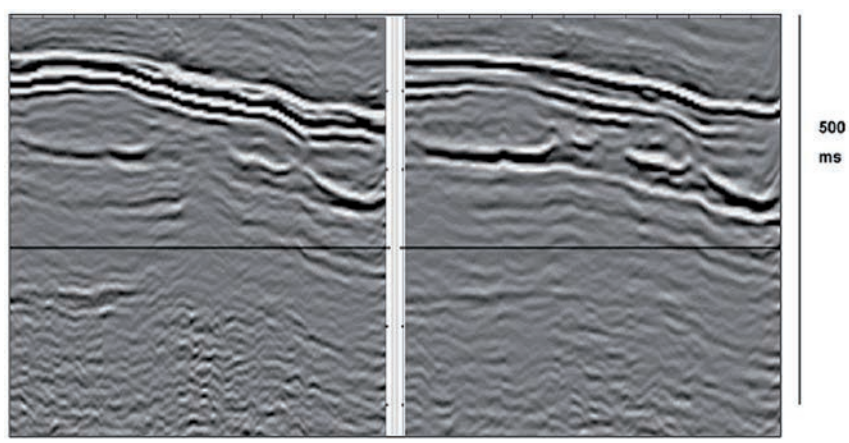

Figure 8 *Sample sections of PreSTM (left) and full-azimuth PreSDM (right) images of the lower Permian model: section of the Zechstein. PreSDM image from depth was scaled to time for comparison.*

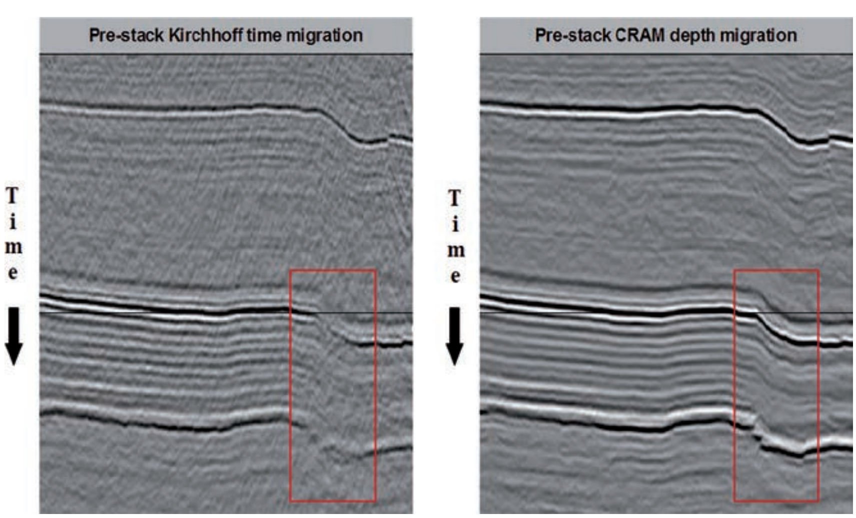

Figure 9 *A sample comparison of image quality: Kirchhoff time migration on the left (formerly used for sectored analysis) versus depth CRAM on the right.*

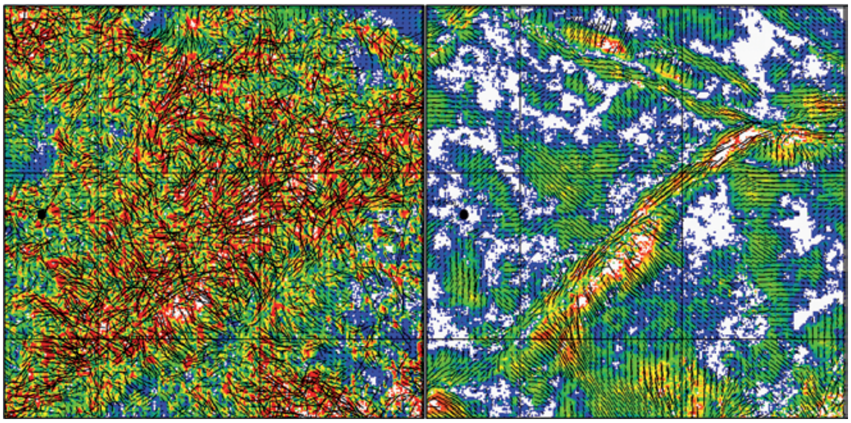

Figure 10 *Comparison of azimuthal anisotropy map obtained from time-domain sectored analysis (left) and a map computed from full-azimuth analysis performed on depth output from EarthStudy 360.*

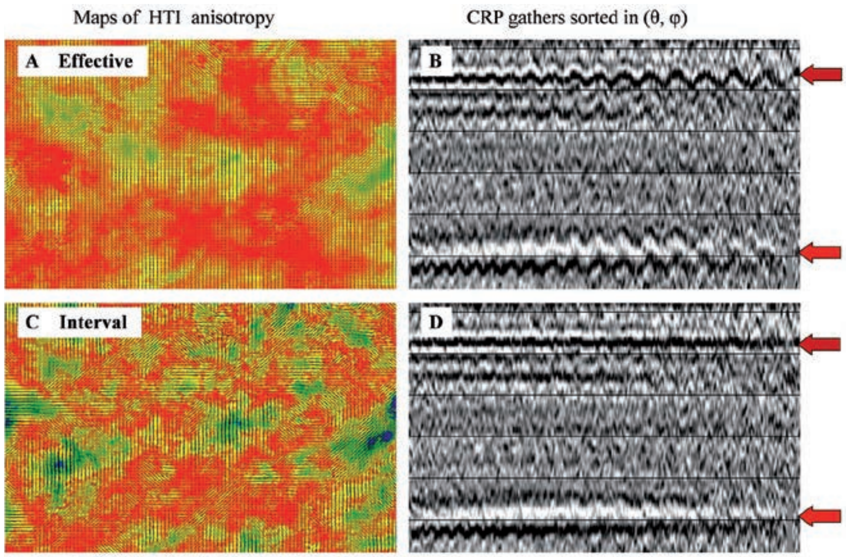

Figure 11 *(A) – Map of effective HTI anisotropy for target (red arrow horizon). (B) – HTI anisotropy seen at the bottom of the overburden (brown arrow horizon) and at the target (red arrow horizon). (C) – Map of interval HTI anisotropy estimated for interval between horizons marked with two arrows. (D) Overburden azimuthal anisotropy compensated with full-azimuth PreSDM, and a clear decrease seen for the target horizon in this sample CRP gather.*

are preferred locations for drilling and shale gas production. The decision space is even more complex: the orientation of horizontal drilling should take into account the orientation of stress and pre-existing fractures to maximize production. The interval map of azimuthal anisotropy can help the geoscientist to make that decision – see example in Figure 11C. Moreover, in practice it was confirmed that such maps, provided by the full-azimuth prestack depth imaging technology, also predict which bodies are resistant to fracturing (see example in Figure 14). In conclusion: 3D FAZ seismic is essential for success in these areas when drilling for shale gas.

More options: diffraction images

In addition to the improvement in image quality and estimate of azimuthal attributes, the full-azimuth depth imaging system used also provided new options for both unconventional and conventional seismic prospecting. The separation of two components of the recorded wavefield – reflection and diffraction energies – revealed subtle features related to small-scale, geologic discontinuities.

Preliminary experience indicates that the use of diffraction imaging in some geologic environments can be even more useful than azimuthal analysis. It can reveal tiny features not seen by geologists using classical reflection images extracted from the same seismic data. That means that new value can be drawn from existing seismic datasets using only azimuth-rich reflection acquisitions. No diffraction acquisition is needed.

Seismic interpretation

Seismic interpretation in this project was based on the workflow presented by Daletka and Rudzki (2013). In this study, it was applied to seismic rich-azimuth data imaged using EarthStudy 360. The methodology was supplemented by performing both acoustic and elastic inversion. Inversion velocities and elastic impedances were extracted in specified intervals, related to particular formations. That workflow allowed comparison of the sector-oriented approach to full-azimuth technology. The latter definitely delivered higher precision. Seismic derived geomechanical parameters were crossplotted with well logs, as shown in Figure 12.

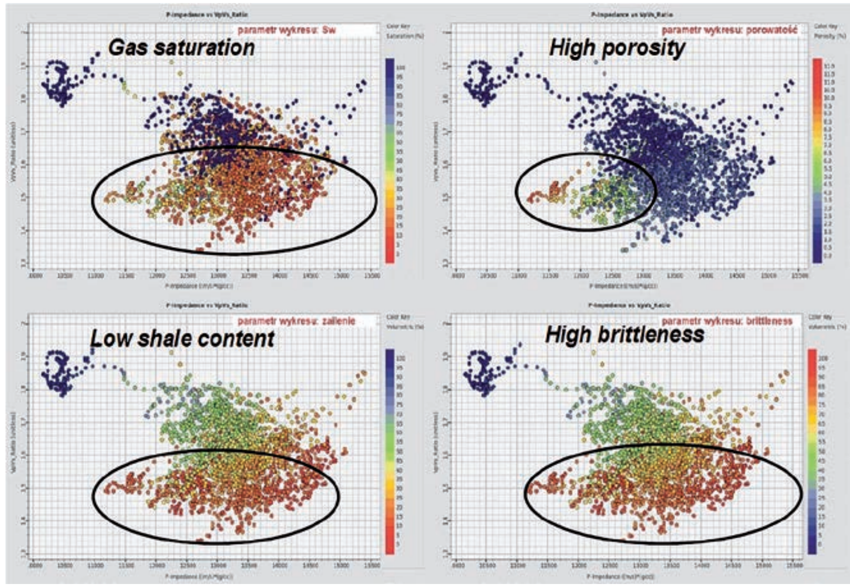

Figure 12 *Correlation of well log and geomechanical parameters provides an assessment of elastic properties.*

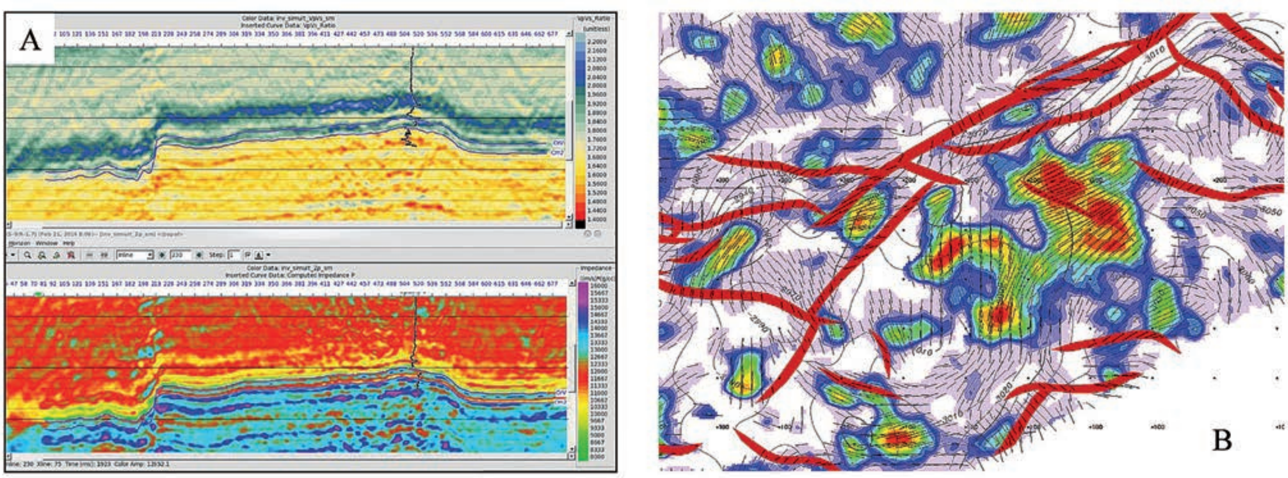

Figure 13 *Panel A: results of simultaneous inversion. Sweet spots were estimated by comparing relationships estimated in Figure 12 with results of simultaneous inversion. Panel B: zoom on composite, azimuthal anisotropy map: colours indicate intensity, and arrows – orientation of anisotropy. Faults are in red.*

Summary of results

The availability of a variety of independent geophysical measurements of physical properties of the examined geology creates an opportunity for integrating additional data into the interpretation process. Integrating borehole information, microseismic fracturing monitoring, surface seismic attributes, and seismic interpretation focused on tectonic system recognition leads to increased vertical recognition of layers.

Three vertical wells were available in the reported area. Two of them were logged before the acquisition of 3D seismic data, while the most recent one was made available after the new depth imaging workflow was completed, and was used to verify imaging precision. While the depth of the shallow horizons, i.e. base of Permian and Silurian, was predicted for the new well with an accuracy of less than a single sample (5 m) of depth imaging, the deep horizons (Ordovician and Pre-Cambrian) around the third well were predicted to an accuracy of less than 10 m.

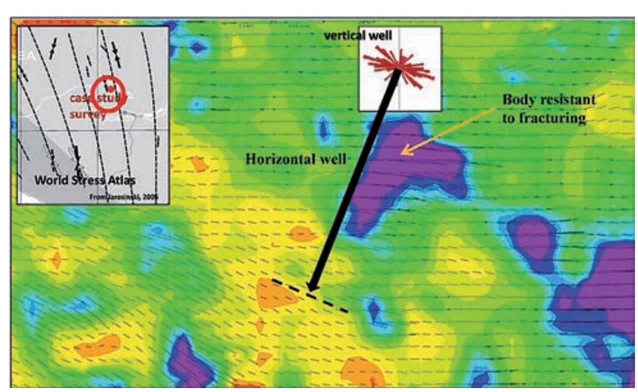

Figure 14 *Seismic-derived anisotropy orientation compared to a rose diagram from well, and to information from microseismic monitoring of fracturing.*

Conclusions

From a seismic perspective, full-azimuth seismic depth imaging is efficient in unconventional plays, such as shale gas, shale oil, tight gas, and in geothermal projects. Compared to traditional time-domain, sectored imaging and data analysis, depth imaging in the local angle domain (a natural domain for geologists) provides more reliable attributes for seismic characterization of reservoirs with azimuthal anisotropy. In areas where azimuthal anisotropy is weak and covered with complex overburden, application of the full-azimuth depth imaging technology can be a basic condition for the economic success of the project.

From a well log perspective, while regional stress may not be relevant to local prospecting, stress orientation predicted from seismic is compatible with an azimuth rose diagram seen in wells, and with information measured from microseismic monitoring during horizontal well fracturing.

From a geological perspective, analysis of the lithostratigraphic formations of Ordovician and Silurian sections revealed significant anisotropy of their mechanical properties. This can be attributed to their original lithologic differentiation, and the later impact of tectonics, including the present field of stress. Identifying the relationship between core data (e.g. mechanical properties, deformations, pattern of fractures), well logs, and seismic is essential to the creation of the local geomechanical model. Such a model is necessary for the correct planning and drilling of horizontal wells, as well as for hydraulic fracturing.

From the perspective of conventional prospecting, the search for conventional traps in areas of complex geology can also profit from this method. Bottom-up ray tracing, the precise use of a 360° view of irregular surfaces, correction for illumination shadows (vertical and lateral), non-stretch NMO, and decomposition into reflection and diffraction components offer the potential to derive new images from archived 3D seismic shot over conventional geology, as well as high-resolution imaging of new, dedicated, rich-azimuth seismic data.

Acknowledgements

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