Building geologically plausible anisotropic depth models using borehole data and horizon-guided interpolation

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Summary

Anisotropic depth imaging places strong focus on delivering quality anisotropic models that increase confidence in the depth positioning of seismic volumes while optimizing image quality. To achieve this, we must calibrate models with well data such as checkshots or markers from one or multiple wells. Because anisotropy can only be determined around boreholes, careful geologically driven extrapolation is required between wells. We present a simple workflow that addresses both aspects. The borehole calibration step includes traveltime-preserved smoothing of the checkshots and deriving anisotropy profiles at wells by manual inversion or localized tomography. Then, horizon-guided interpolation creates volumes of Thomsen parameters propagated consistently with the subsurface geology. Once new anisotropy volumes are derived, the entire velocity cube is revised to preserve normal moveout velocities. As a final step, the updated model is stretched into new seismic image depth. The presented case study applies this workflow to wide-azimuth seismic data from the Gulf of Mexico where a VTI depth model is built for an area of 100 outer continental shelf (OCS) lease blocks using 18 wells with checkshots.

Introduction

Anisotropic depth imaging has become a new industry standard. Vertical transverse isotropy (VTI) is one of the widely used types of anisotropic depth model. A VTI model velocity field needs three parameters: vertical velocity along the symmetry axis (V_{P0}) and Thomsen anisotropy parameters ε and δ. The challenge of building such models is that we cannot rely on seismic tomography to derive multiple parameters in an entire volume because inversion of seismic data alone for all three parameters is highly nonunique (Tsvankin, 2001). Current industry practice consists of deriving a single smooth profile of Thomsen parameters ε and δ based on well control in areas of horizontal layering. This profile is propagated into an entire volume by simply hanging it off the water bottom or another shallow horizon. Then, Thomsen parameters are kept frozen, whereas, vertical velocity is updated by seismic reflection tomography (Woodward et al., 2008). Such a practice represents an improvement compared to isotropic models used in the past, but suffers from a series of limitations:

- Use of a single anisotropy profile ignores lateral variation of anisotropy in the subsurface;
- This single anisotropy profile is overly smoothed in the vertical direction. Finer details are filtered out even if present because they cannot be accurately propagated in a 3D volume with complex geology;
- Anisotropic property distribution mimics water-bottom topography but not subsurface geology.

The study objective is to describe a simple new workflow that overcomes these limitations.

Simple workflow

We assume that several wells are available with some measurements suitable for velocity model building (checkshot, VSP, markers, sonic logs). We aim to build a VTI depth model that fits all well data as well as existing seismic data. New workflow consists of four major steps:

1. Derive local anisotropy profiles/models around existing wells.
2. Pick set of key seismic horizons.
3. Populate volumes of anisotropic parameters using horizon-guided interpolation of anisotropic profiles derived at wells.
4. Update velocity only by using reflection tomography.

Obtaining local anisotropy profiles at the wells can be done using 1D manual layer-stripping inversion or local tomography (Bakulin et al., 2009). Both of these approaches assume that anisotropy is slowly varying along horizontal or dipping layers. Horizons are picked to guide the propagation of anisotropic properties between the wells. The third step that interpolates anisotropic parameters between the well consists of four sub-steps:

1. Convert profiles of Thomsen parameters along the wells from well depth to seismic image depth.
2. Interpolate Thomsen parameters between wells using horizons in seismic image depth.
3. Revise vertical velocity in a volume to maintain the same normal moveout velocity.
4. Transform VTI velocity cube into a new seismic image depth.

The first step is required to bring the anisotropy profiles derived in “well depth” to “seismic image depth” where horizons are derived. After interpolation and velocity update, the model is converted to “new seismic image depth” controlled by updated velocity. In the examples below, it is implemented as a simple vertical stretch.

Gulf of Mexico case study

Let us apply the new workflow to a case study from the northern part of the Green Canyon area, Gulf of Mexico. The wide-azimuth seismic data consists of 100 OCS

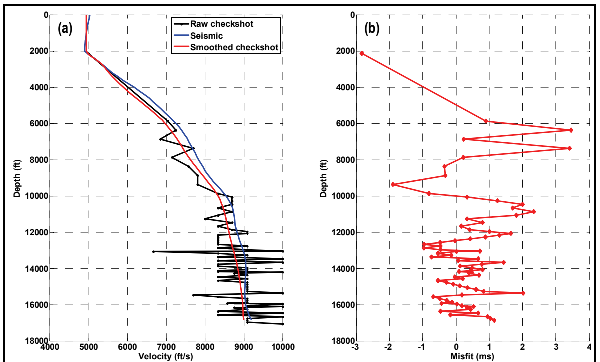

Figure 1: (a) Velocity profiles at the well location showing the initial seismic model derived with tomography, raw checkshot velocity, and smoothed checkshot velocity; (b) traveltime misfit between measured checkshot and velocity profile derived by checkshot smoothing.

blocks. Well data are represented by 18 wells with checkshots selected in areas of small geological dip. Smooth vertical well velocity functions are derived at each well by traveltime-preserved checkshot smoothing using the algorithm of Lizarralde and Swift (1999) modified to handle uneven sampling. This process captures the low-frequency trend of the well velocity and ensures that there is no bias that may distort time-depth conversion (Figure 1). High-frequency velocity oscillations are not appropriate for a macro velocity model and are, therefore, excluded. Once vertical velocity is constrained by well data, we can derive Thomsen parameters from the seismic data. In this study, we have chosen to perform local 1D manual layer-stripping inversion at each well location where we fixed the velocity to smoothed checkshot velocity and then derived profiles of Thomsen's ε and δ. Figure 2a and 2b verify that common-image-point (CIP) gathers are flat for the both initial and derived models; however the borehole-calibrated model has velocity equal to well velocity. The new model has larger anisotropy values and suggests the presence of shallow layers with higher anisotropy that were not included in the initial model (Figure 2c). A slower velocity makes all seismic events move upwards.

Borehole data only allow estimation of anisotropy around wells. Between wells we assume anisotropy is controlled by lithology and perform horizon-guided interpolation of profiles derived at well locations. Because horizons were picked in the initial seismic volume, we convert anisotropic profiles to an old seismic image depth before interpolation to make them consistent. In this study, we used a simple 1D conversion by first converting them to time using well velocity followed by conversion to depth using seismic vertical velocity in the initial model. After horizon-guided interpolation of 18 well profiles with seven horizons, we obtain volumes of Thomsen parameters. For each layer

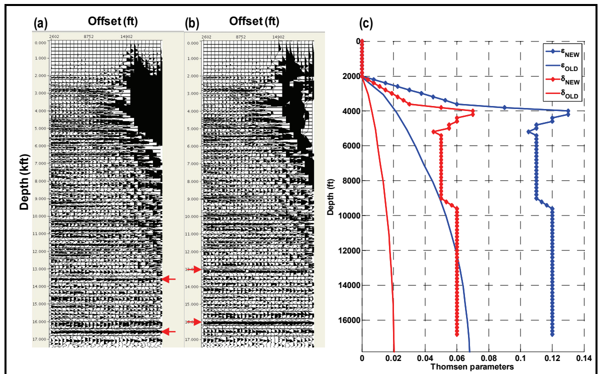

Figure 2: Common-image point gathers for initial (a) and calibrated model (b), derived from 1D manual layer-stripping inversion at the well location; (c) profiles of Thomsen parameter for initial (solid lines) and derived model (solid lines with circles). Note upward movement of seismic horizons shown by red arrows.

except the deepest one, top and bottom surfaces are used as a guide; thus by design, anisotropy generally conforms to layers, whereas it varies laterally if anisotropy values differ in different wells.

To preserve interval normal moveout velocity, we also revise the vertical velocity using the simple 1D equation

$$V_{P0}^{new} = V_{P0}^{old}\sqrt{\frac{(1+2\delta^{old})}{(1+2\delta^{new})}}.$$

At well locations in a 1D Earth, such a correction is expected to convert seismic velocity into well velocity while maintaining the same gather flatness. In laterally heterogeneous models, we expect velocity to become closer to a well velocity and also facilitate quicker convergence for subsequent tomography iterations that update vertical velocity only. At the end, we convert the model into a new seismic image depth that is depth controlled by revised seismic vertical velocity. Here, it was done using a simple 1D transform to time using initial velocity followed by conversion to depth using revised seismic vertical velocity. Figure 3 contrasts Thomsen's δ volumes for initial and calibrated models. In the initial model, anisotropy is low and its variation is parallel to the water bottom. In contrast, the calibrated model has higher anisotropy that conforms to subsurface geology. Figure 4 shows a cross section of Thomsen's ε parameter, where one can see general conformance to a picked seismic horizons with a mild lateral variation between the wells. An additional iteration of tomography for velocity only was run to completely flatten the gathers because a simple 1D velocity correction performed during the workflow is not accurate in the case of steep dips. Rapid beam migration with the calibrated model after tomography reveals that events move up by as much as 600 ft (Figure 5). There is no significant improve-

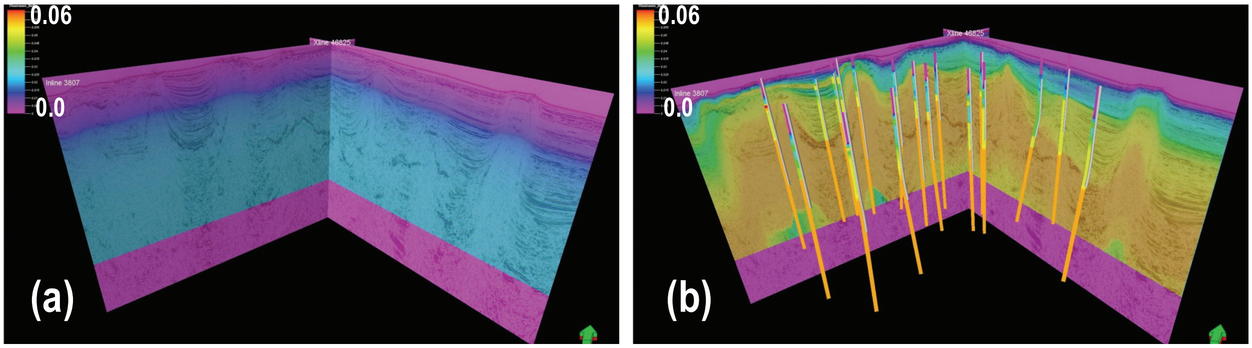

Figure 3: Thomsen's δ volume for (a) initial model and (b) final calibrated model. Thomsen's δ profiles are shown along the tracks of 18 wells.

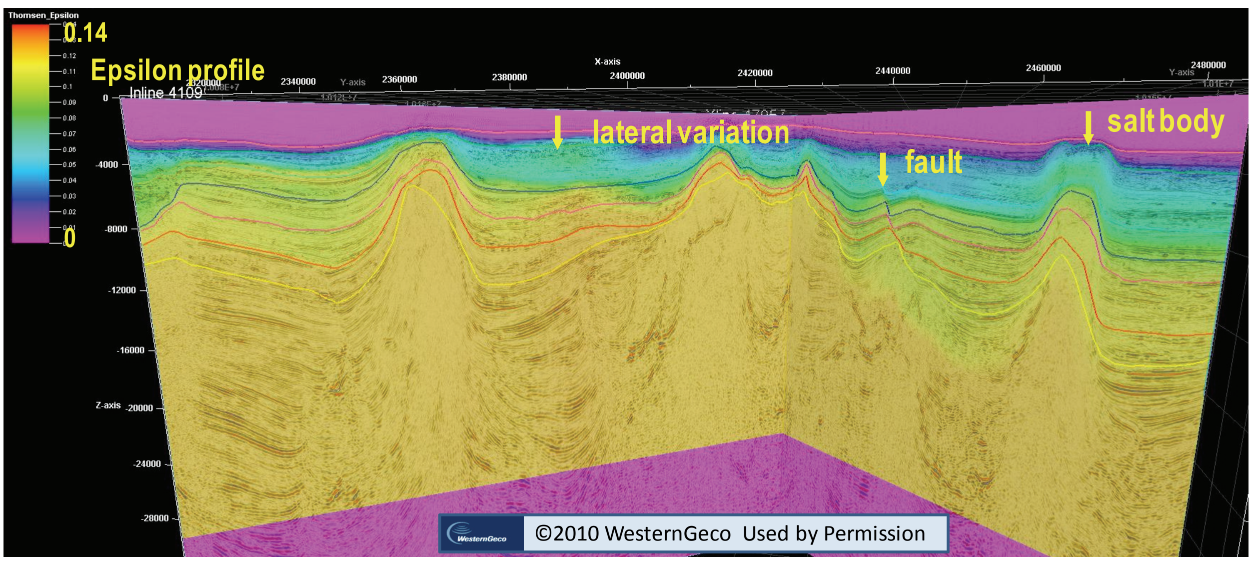

Figure 4: Vertical cross sections through a Thomsen's ε volume for a borehole-calibrated model. Lines show interpreted horizons used for interpolation of Thomsen parameters. (courtesy WesternGeco)

ment in focusing because the new model largely results in a shift of all events predominantly upwards. However, we observe significant reduction of average misties from up to 500 ft to less than 100 ft.

Conclusions

We described a simplified workflow that allows building more geologically plausible anisotropic depth models and incorporates all well data in the area of interest. This workflow assumes that anisotropic parameters are controlled by lithology and thus conform to main geological layers. Therefore, anisotropic parameters derived at well locations are interpolated into volume using picked seismic horizons. We presented a case study from the Gulf of Mexico where we constructed a VTI model for an area of 100 OCS blocks using wide-azimuth seismic data and 18 wells with checkshots. In this study, we constrained velocity around the wells by measured checkshots and performed 1D manual layer stripping inversion for Thomsen parameters. To conform to the 1D assumption of the inversion, we only used vertical wells in areas of mostly flat dips. Volumes of Thomsen parameters were constructed by horizon-guided interpolation of derived well profiles. In essence, we derived an improved version of an initial model that has much more realistic Thomsen parameters; whereas, reflection tomography updated vertical velocity in the entire volume. Note that grid tomography does not assume conformance of velocity to layers, thus allowing us to handle the most general cases. The described workflow is extendable to complex geological settings provided that layer stripping inversion is replaced by localized tomography with well data. Localized anisotropic tomography with well information can overcome the above limitations and derive a local anisotropic model around deviated wells in the presence of dipping layers and tilted transverse isotropy.

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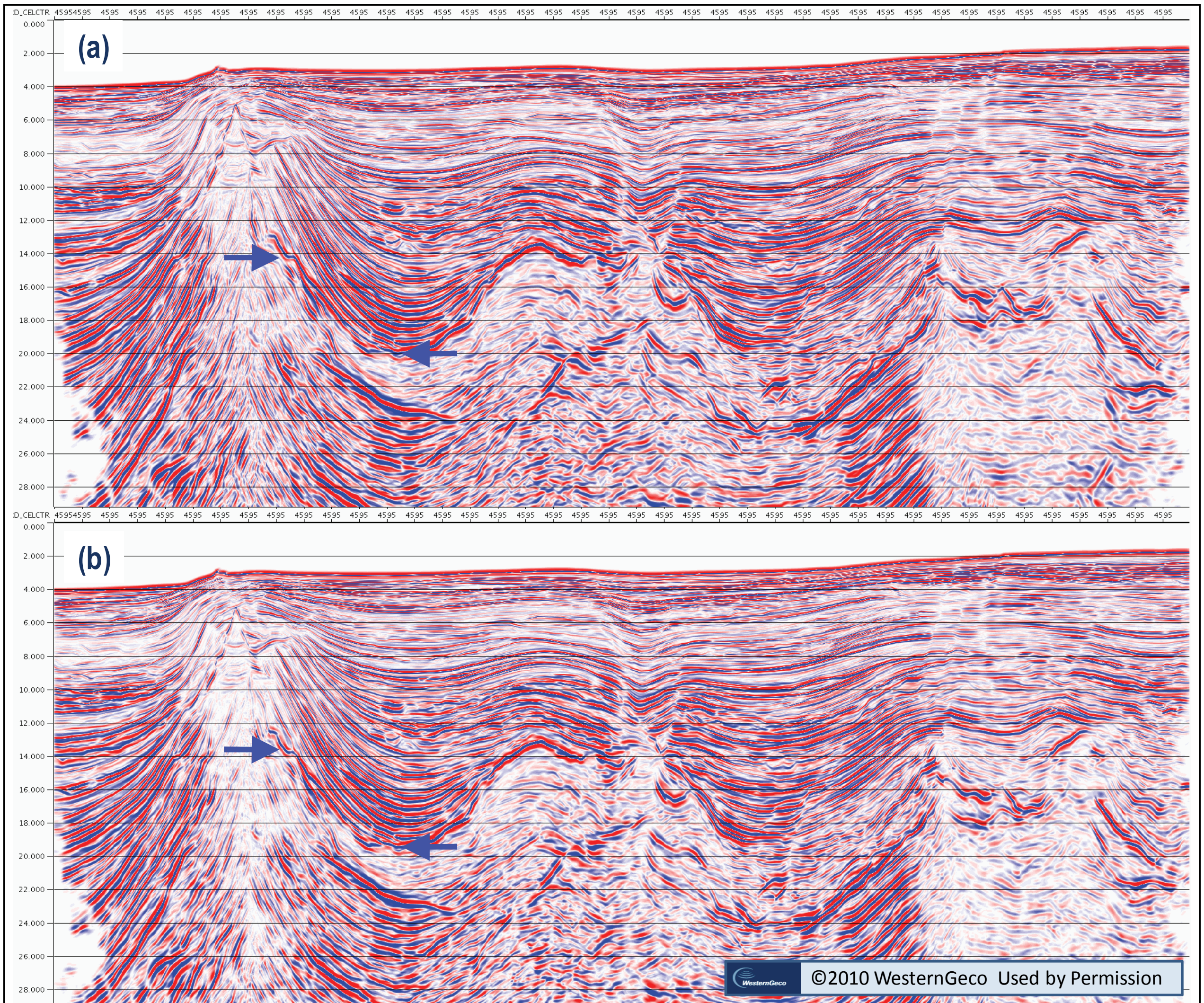

Figure 4: Images (sediment flood) obtained by rapid beam migration using different model scenarios: (a) initial model; (b) borehole-calibrated model constructed with described workflow and run through velocity-only tomography (courtesy WesternGeco). Note general shift upwards increasing with depth in the new image. Such a shift reduced well misties from 500 ft to less than 100 ft.

EDITED REFERENCES

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