Global method for seismic-well tie based on real time synthetic model

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Summary

This paper presents an original global method which computes a real time synthetic model from seismic data, during the well-tie process. Based on a relative geological time model resulting from global seismic interpretation and on synthetic seismograms, this technique intends to give a comprehensive view of the seismic-well tie and completes the standard workflow. Instead of correlating the synthetic log with the nearest seismic traces only in the vicinity of the well trajectory, a synthetic model is computed in real time by propagating the synthetic seismogram into the geological model. Minimizing the relative errors between the real seismic data and the synthetic model automatically enables the determination of the optimum time shift value to apply to the current time-depth relationship. Moreover, as stretching and squeezing the synthetic log is still controversial, the method allows to check and understand the global consequences of local change in the time-depth relationship. Such a technique can be used on a single well or on multi-well analysis. In the latter case, reference tied wells are used as hard constraints for the synthetic model. The method highlights any mismatches or polarity change and therefore is more sensitive to well-to-seismic mistie. Applied to the North Sea K05 block dataset, this approach has clearly shown successful results in improving the well calibration in complex geological areas. Using more advanced kriging techniques, the method also opens the path for future applications where rock properties or velocity models would be compared.

Introduction

Most of the seismic-well tie techniques are based on the comparison of synthetic seismograms and seismic traces in the neighbourhood of the well path. Even though this workflow is widely used, in highly deformed layers or in faulted media along the well, well calibration in the seismic two-way time (TWT) domain can be more challenging. To overcome this task, we propose a global method wherein the seismic-well tie involves comparing seismic data and real-time computed synthetic models obtained from seismic interpretation.

Standard seismic-well tie process

Seismic reflection data yields a 2D or 3D earth image based on large scale acoustic impedance contrasts and relatively low frequency content in time domain, whereas well logs analysis is performed at higher frequencies, in depth domain. Connecting those two types of information remains critical to understand the spatial extensions of rock physics properties and therefore to characterize reservoir geometries. The common method consists in defining the correct time-depth relationship at the well location by creating synthetic seismograms and then correlating them with real seismic traces. Several processes to perform a well-tie have already been proposed (Walden and White, 1984; White and Hu, 1997; White and Simm, 2003; Duchesne and Gaillot, 2011; Herrera and van der Baan, 2012).

Based on the recorded well logs, a synthetic seismogram intends to simulate seismic trace data acquired with reflection techniques at the well location. A synthetic trace is computed from the convolutional model below:

$$s(t) = w(t) * r(t) + n(t)$$

where s is the synthetic trace, w the wavelet convolved with the reflectivity log r corresponding to the earth's impulse response generally obtained from sonic and density logs, and n the random ambient noise which can be neglected.

The seismic-well tie process is used to correlate well log data to the seismic volume in the vicinity of the well. The synthetic seismogram is then compared to the nearest seismic traces of the well trajectory. The quality of the match depends mainly on i) the frequency content, ii) the correlation of high amplitudes and iii) transparent zones with low reflectivity (Newrick, 2012). An initial time-depth relationship, either based on the check shots and/or the sonic log calibration is assigned to the well. If some mismatches are observed, various processes are known. Sometimes a simple time shift can be sufficient. Otherwise a stretch and squeeze can be applied to the synthetic trace. That is however a controversial method (White, 1998; Newrick, 2012) and the geophysicist has to use it very carefully.

Method to create synthetic models

The proposed method consists in computing a real time synthetic seismic model from the synthetic logs and in comparing it with the seismic volume, directly during the seismic-well tie process. With such a global approach, the validation of the well calibration is not only performed locally but also at the scale of the seismic volume.

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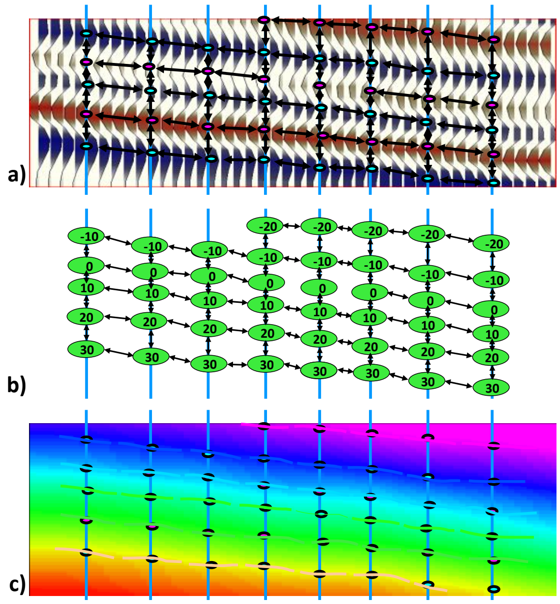

Figure 1: *Workflow of the relative geological time model method. a) Creation of a grid from seismic traces and automatic tracking of horizons. b) Relative geological times assignment. c) Resulted relative time model.*

The synthetic model is obtained from one or several synthetic seismograms along the well path and a Relative Geological Time (RGT) model (Pauget et al., 2009). The RGT model comes from a global seismic interpretation method, which can be summarized as a two-step workflow (Figure 1). During the first step, horizons are automatically tracked within the entire seismic volume to constrain a grid and a relative geological time is computed for each point. The seismic interpreter then checks the auto-picked horizons and refined them locally inside the grid until an optimum solution is obtained. Such a method has already been tested on various case studies with different geologies (Gupta et al., 2008; Lemaire et al., 2010; Beller et al., 2012; Vidalie et al., 2012; Schmidt et al., 2013).

In more details, the synthetic seismic volume is generated by interpolating the synthetic seismogram from one or several wells, within the RGT model (Figure 2). The interpolation follows the geological time values of the model and is calculated using the inverse distance weighting method:

$$u(x) = \frac{\sum_{i=0}^{n} w_i(x) u_k}{\sum_{i=0}^{n} w_i(x)},$$

$$\text{with} \quad w_i(x) = \frac{1}{d(x, x_i)^2}$$

where $u(x)$ corresponds to any interpolated point at position x, $w_i(x)$ the weighted values related to the seed i and $d(x,x_i)$ the distance between the two locations.

Applied during the well-tie process, such a method makes the synthetic model computed and updated in real time for any change made on the synthetic logs such as stretching and squeezing or the input wavelet. The comparison between the real and synthetic seismic data is then done globally and does not depend anymore on only a few traces located in the vicinity of the well.

The optimum time shift can automatically be calculated by minimizing the error between the synthetic model and the real seismic data, for each sample, as defined below:

$$\text{Mean error } = \frac{1}{n} \sum_{i=0}^{n} abs(\mathrm{N}_{ref,i} - \mathrm{N}_{syn,i})$$

$$\text{with} \quad \mathrm{N}_{image,i} = \frac{p_i - I_{min}}{I_{max} - I_{min}}$$

where n is the number of common pixels between the reference and the synthetic images, I_{min} and I_{max} their extreme values and p the current pixel amplitude value.

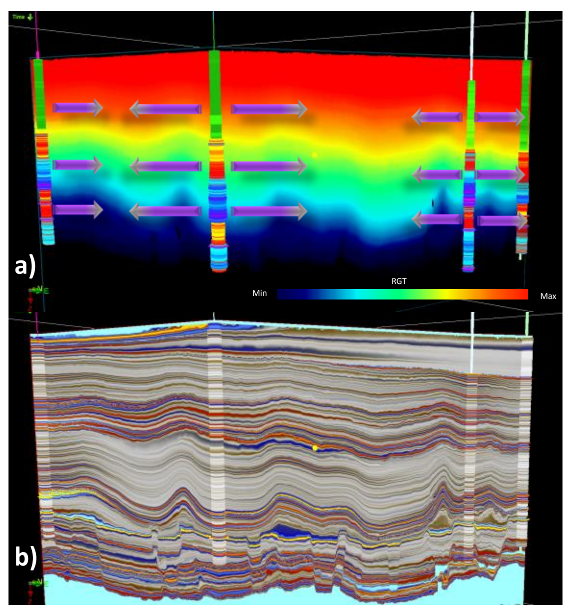

Figure 2: *Propagation of the well log data into the RGT model. a) Propagation of the well log data following the relative geological times of the RGT model. b) Example of a synthetic volume based on the RGT model and well logs.*

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Besides, this model can also take into account several synthetic logs from other wells and therefore allows a multi-well analysis. For example, if several calibrated wells are used to propagate the synthetic data, the synthetic model will be more sensitive to mismatches. For each change in the time-depth relationship, the value of the mean error is used as a confidence factor in the well calibration.

Application to North Sea data

The method was applied to a few wells belonging to the K05 block located in the North Sea, where a RGT model was obtained from Carboniferous to Paleogene (Daynac et al., 2014). The area is mainly characterized by a complex fault system at the base of salt, where the reservoir lies. The synthetic seismic logs were generated using a 25Hz-Ricker wavelet.

- Automatic time shift

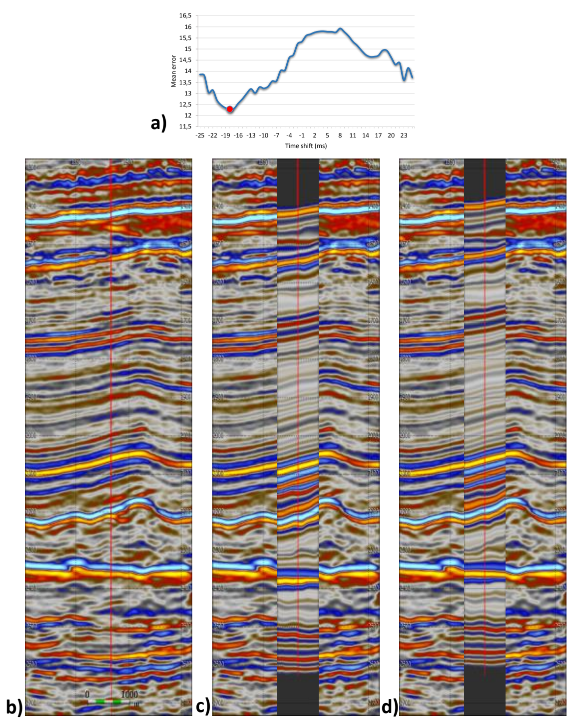

Figure 3: *Seismic-well tie for the K05-12 well. a) Mean errors between the seismic reference volume and the synthetic models with the time shifts applied to the initial time-depth relationship. The red point shows the minimum error at a time shift of -18ms. b) Reference seismic volume with the K05-12 well trajectory in red. c) Synthetic model computed from the initial time-depth relationship. d) Synthetic model with the optimum time shift value according to the a) curve.*

The first calibration was done on the K05-12 well. Automatic time shifts were applied to the current time-depth relationship, from -25 to +25 milliseconds with a 1-millisecond step. Along the arbitrary line crossing the well path, the difference was calculated between the real seismic and the synthetic model for each time shift. The presumed best time shift corresponds to the minimum error, as shown in Figure 3a.

By comparing the different views of the arbitrary line, the quality of the presumed best match can easily be verified (Figure 3d), even on traces located away from the well path. The main reflections of the synthetic log are perfectly correlated to the seismic ones. In the upper part, some misties are still present and were handled by adjusting the time-depth relationship with stretch and squeeze operations.

- Consequences of stretching and squeezing

In this case, a multi-well analysis was used. Although the seismic-well tie was applied to the K05-12 well, the synthetic model took into account the tied synthetic log of the K04-A-01 well. The error function was computed on the arbitrary line crossing those two wells, distant of about 14 kilometers (Figure 4a).

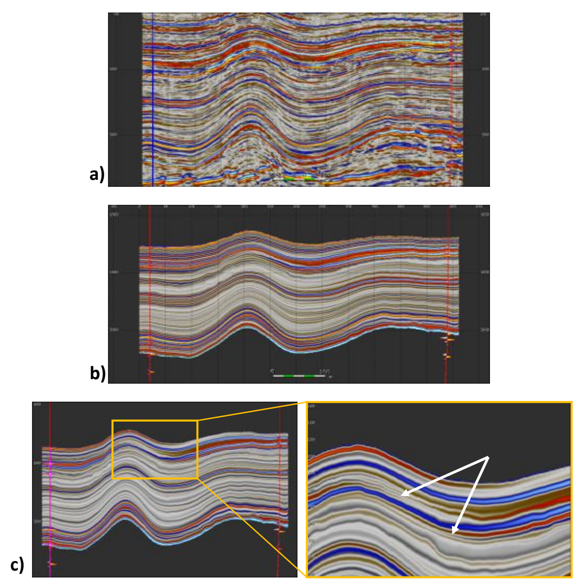

Figure 4: *Seismic-well tie for the K05-12 well with the K04-A-01 well as reference. a) Seismic arbitrary line along the K05-12 (blue) and K04-A-01 (red) wells. b) Synthetic model after stretching and squeezing the K05-12 synthetic log to match with the seismic data. c) Example of a synthetic model computed from a wrong stretching operation, the white arrows show polarity errors and non-continuous synthetic reflections.*

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In such a configuration, the K04-A-01 reference tied well is used as a constraint. Any change in the time-depth relationship of the K05-12 well, is reflected on the synthetic model (Figure 4c). Wrong polarities, misties or lateral non-continuities are clearly notable. The corrections of the time-depth relationship can then be applied with a global control of the data and therefore with more confidence (Figure 4b). Moreover, the mean error estimate allows getting quantitative information related to the best match, in addition to the correlation factor between single synthetic and seismic traces.

Conclusions

This paper introduced an original method for seismic-well tie using a 2D or a 3D synthetic seismic model derived from the seismic global interpretation. Based on a relative geological time model and well logging data, a synthetic model is computed in real time during the seismic-well tie process. By estimating the global error between the synthetic and the real seismic data, the optimum time shift and the best wavelet are automatically calculated and the most appropriate time-depth relationship is obtained. From either a single well or a multi-well analysis, the technique minimizes well-known incertitude of the seismic-well tie process and convolutional model (Yilmaz, 2001). Applied to a real dataset in the North Sea, the K05 block, it has shown relevant results to calibrate wells and estimate the error in a more robust way. In the future, the synthetic seismic model could also take into account kriging techniques. Other well log properties or interval velocities could also be used to better constrain the calibration process.

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Note: This reference list is a copyedited version of the reference list submitted by the author. Reference lists for the 2015 SEG Technical Program Expanded Abstracts have been copyedited so that references provided with the online metadata for each paper will achieve a high degree of linking to cited sources that appear on the Web.

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