Joint AVO inversion for time-lapse elastic reservoir properties: Hangingstone heavy oilfield, Alberta

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Summary

We developed a time-lapse AVO inversion method, based on Bayesian method, in which all available seismic data can be used to obtain elastic properties (V_P, V_S, and ρ) and the changes between baseline and monitor surveys. The inverted elastic properties and the changes are consistent with the seismic data and prior information. Furthermore, the method is applicable to incomplete time-lapse multicomponent data sets. Preliminary tests on synthetic data based on log information from the Hangingstone heavy oilfiled, Alberta, shows promising results.

Introduction

For time-lapse seismic inversion, it is common that baseline and monitor survey data are separately inverted to elastic properties. The changes of the elastic properties due to production are obtained from difference in the two inversion results with time misalignment correction. Buland and Ouair (2006) proposed time-lapse inversion based on the Bayesian theorem. In the Bayesian framework, they regard elastic property changes as model parameters and obtain the posterior distribution, which are consistent with both prior information and the seismic data in statistical sense. We take a similar approach as Buland and Ouair (2006). But, we use both baseline and monitor survey data, instead of using only the differences, and simultaneously obtain elastic properties at baseline survey and the changes at monitor survey with the uncertainties. Although Buland and Ouair (2006) assume the same wavelet for both baseline and monitor surveys, it is not unusual that time-lapse seismic data have different frequency bands. Our method allows us to use individual wavelets for each seismic data. Furthermore, it can be extended to multicomponent seismic data.

Study Area

The study area is located in the Hangingstone heavy oil field, approximately 50 km south-southwest of Fort McMurray, Alberta, Canada (Figure 1). A SAGD operation was started there in 1997 and heavy oil of 8.5º API gravity has been produced since 1999. The oil sand reservoirs occur in the Lower Cretaceous McMurray formation and are about 300 m in depth (Takahashi et al., 2006). The sedimentary environment is interpreted to consist of fluvial to upper estuarine channel fill deposits. The reservoirs correspond to vertically stacked, incised valley fill sands with very complex vertical and horizontal distributions. For efficient production and field development, it is extremely important to estimate the reservoir distributions and monitor steam movement within reservoirs. For these purposes, a time-lapse seismic survey was conducted (Nakayama et al., 2008); baseline survey (5.4 km2) in February 2002 and monitor survey (4.3 km2) in March 2006 (Figure 2). The field acquisition parameters are almost same between them. The only major difference is the receiver type; three-component digital sensors were used in the monitor survey while analog geophone arrays were used in the baseline survey. Thus, both PP and PS data are available as monitor survey (Figure 3) while only PP data is available as baseline survey. Furthermore, it is noted that frequency band is different between the baseline PP data and the monitor PP data.

Figure 1. The study area (arrow) and oil sand reservoirs in Alberta, Canada.

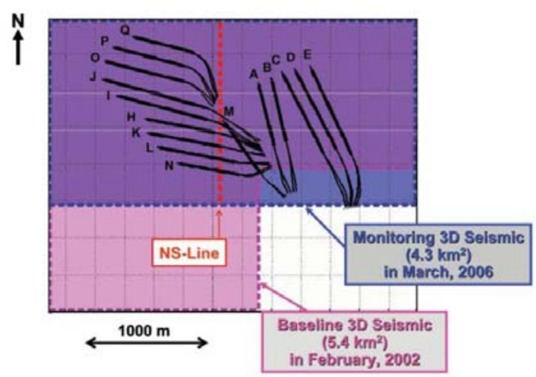

Figure 2. Map of the study area with time-lapse 3D seismic survey and SAGD well locations. Black solid lines represent the SAGD well paths (from Nakayama et al., 2008).

Time-Lapse Inversion Method

For simplicity, we first consider a single-interface P-wave reflection coefficient for time-lapse analysis. The linear Aki and Richards (1980) approximation to Zoeppritz equations for the P-wave reflection coefficient, *d,* is expressed with respect to reflectivities as:

$$
\begin{aligned}
d_1 &= A_\alpha(\theta_1,\gamma_1)L_{\alpha 1} + A_\beta(\theta_1,\gamma_1)L_{\beta 1} + A_\rho(\theta_1,\gamma_1)L_{\rho 1} \\
d_2 &= A_\alpha(\theta_2,\gamma_2)L_{\alpha 2} + A_\beta(\theta_2,\gamma_2)L_{\beta 2} + A_\rho(\theta_2,\gamma_2)L_{\rho 2} \quad ,
\end{aligned}
\tag{1}
$$

where the coefficient A_α, A_β and A_ρ are functions of the P-wave incident angle, θ, and $\gamma=\beta/\alpha$. L_α, L_β and L_ρ are reflectivity of P- & S-wave velocities, and density, respectively. The subscripts 1 and 2 represent baseline and monitor surveys.

The reflectivity at monitor survey is decomposed to two terms: the corresponding reflectivity from the baseline survey (L_1) and the change between baseline and monitor surveys (ΔL):

$$
L_{\alpha 2} = L_{\alpha 1} + \Delta L_\alpha \quad L_{\beta 2} = L_{\beta 1} + \Delta L_\beta \quad L_\rho = L_{\rho 1} + \Delta L_\rho \ , \tag{2}
$$

By substituting (2) into (1),

$$
\begin{aligned}
d_1 &= A_{\alpha 1}L_{\alpha 1} + A_{\beta 1}L_{\beta 1} + A_{\rho 1}L_{\rho 1} \\
d_2 &= A_{\alpha 2}L_{\alpha 1} + A_{\beta 2}L_{\beta 1} + A_{\rho 2}L_{\rho 1} + A_{\alpha 2}\Delta L_\alpha + A_{\beta 2}\Delta L_\beta + A_{\rho 2}\Delta L_\rho \ ,
\end{aligned}
\tag{3}
$$

Assuming that we have *m* different source-receiver offsets for both the baseline and monitor surveys, a linear system of *2m* linear equations with 6 unknown parameters can be expressed as:

$$
\begin{bmatrix} d_1(\theta_1) \\ \vdots \\ d_1(\theta_m) \\ d_2(\theta_1) \\ \vdots \\ d_2(\theta_m) \end{bmatrix}_{2m\times 1}
=
\begin{bmatrix}
A_{\alpha 1}(\theta_1) & A_{\beta 1}(\theta_1) & A_{\rho 1}(\theta_1) & 0 & 0 & 0 \\
\vdots & \vdots & \vdots & \vdots & \vdots & \vdots \\
A_{\alpha 1}(\theta_m) & A_{\beta 1}(\theta_m) & A_{\rho 1}(\theta_m) & 0 & 0 & 0 \\
A_{\alpha 2}(\theta_1) & A_{\beta 2}(\theta_1) & A_{\rho 2}(\theta_1) & A_{\alpha 2}(\theta_1) & A_{\beta 2}(\theta_1) & A_{\rho 2}(\theta_1) \\
\vdots & \vdots & \vdots & \vdots & \vdots & \vdots \\
A_{\alpha 2}(\theta_m) & A_{\beta 2}(\theta_m) & A_{\rho 2}(\theta_m) & A_{\alpha 2}(\theta_m) & A_{\beta 2}(\theta_m) & A_{\rho 2}(\theta_m)
\end{bmatrix}_{2m\times 6}
\begin{bmatrix} L_\alpha \\ L_\beta \\ L_\rho \\ \Delta L_\alpha \\ \Delta L_\beta \\ \Delta L_\rho \end{bmatrix}_{6\times 1} ,
$$

The rows from first to m^{th} correspond to baseline data while the remaining rows correspond to monitor data. Because the above equation has a well-known linear matrix form, $d = Gm$, the unknown parameters can be solved in least-square fashion. Here, we prefer stochastic method based on the Bayesian theorem (e.g., Buland and Ouair, 2006). The posterior distribution, $\hat{m}$, can be expressed

$$
\hat{\mathbf{m}} = \left(\mathbf{G}^T\mathbf{C}_\mathbf{n}^{-1}\mathbf{G} + \mathbf{C}_\mathbf{m}^{-1}\right)^{-1}\left(\mathbf{G}^T\mathbf{C}_\mathbf{n}^{-1}\mathbf{d} + \mathbf{C}_\mathbf{m}^{-1}\mathbf{m_0}\right) , \tag{4}
$$

where C_n and C_m is covariance matrix of seismic data and model parameters, respectively. m_0 is a prior mean value that corresponds to low-frequency model of unknown parameters in our problem.

The method for single-interface reflection coefficient can be applied to time-continuous amplitude data by some modifications, including taking natural logarithm of model parameters (e.g., Buland and More, 2003). Furthermore, with help of the Bayesian theorem, the method can be extended to multicomponent data set (e.g., Lortzer and Berkhout, 1993), assuming that the seismic data employed are corrected for vertical time misalignment.

Synthetic Tests

Because acoustic and density well logs from the repeat survey are not available in this field, we use an empirical rock physics model (Kato et al., 2008), which was established based on laboratory measurements on heavy oil sands, to create synthetic well log data at monitor survey. Using the actual and synthetic well logs, we construct synthetic seismic data based on the convolution model, where a zero-phase Ricker wavelet is used. The dominant frequency is set individually for each data type; 75 Hz for PP-base, 100 Hz for PP-monitor, and 85 Hz for PS-monitor, respectively. The maximum P-wave incident angle assumed to be 45º for all seismic data. Next, we add random noise to the synthetic seismic data so that we obtain the data with S/N ratio being 2. By applying our method, the seismic data in reservoir layer are inverted to six parameters (α, β, ρ, Δα, Δβ, and Δρ), while only three parameters (α, β, and ρ) are obtained in the layers above and below reservoirs because the elastic properties are assumed to be time-invariant. For the covariance matrix of the seismic data and wavelet, we use actual values computed from the data. The covariance matrix of the model parameters is determined from the well log with the rock physics model. A prior mean values (m0) are obtained by applying a low-pass filter to the well log.

Figure 4 shows a crossplot between the inversion result and well log for PP alone inversion (PP at baseline and PP at monitor surveys with S/N ratio being 2). The circle and triangular represent reservoir layer and layer above it. The inversion result shows good agreement with well log for P-wave at baseline. Figure 5 shows the same crossplot as Figure 4 except for joint inversion (PP at baseline and PP & PS at monitor survey with same S/N ratio). Compared to the PP alone inversion, the joint inversion result shows better agreement with well log for all parameters, particularly for S-wave velocity at baseline and density change at monitor survey significant improvement can be observed.

Joint AVO inversion

Summary

We have developed time-lapse AVO inversion method based on the Bayesian theorem, in which all available seismic data can be used to obtain elastic properties, as well as the changes between baseline and monitor surveys. The inverted elastic properties and the changes are consistent with the seismic data and prior information. Furthermore, the method can be applied to incomplete time-lapse multicomponent seismic data sets, like our study area, in which PP data at baseline and PP & PS at monitor surveys are available. Preliminary tests on synthetic data show promising results. Currently we are applying the method to the Hangingstone field data.

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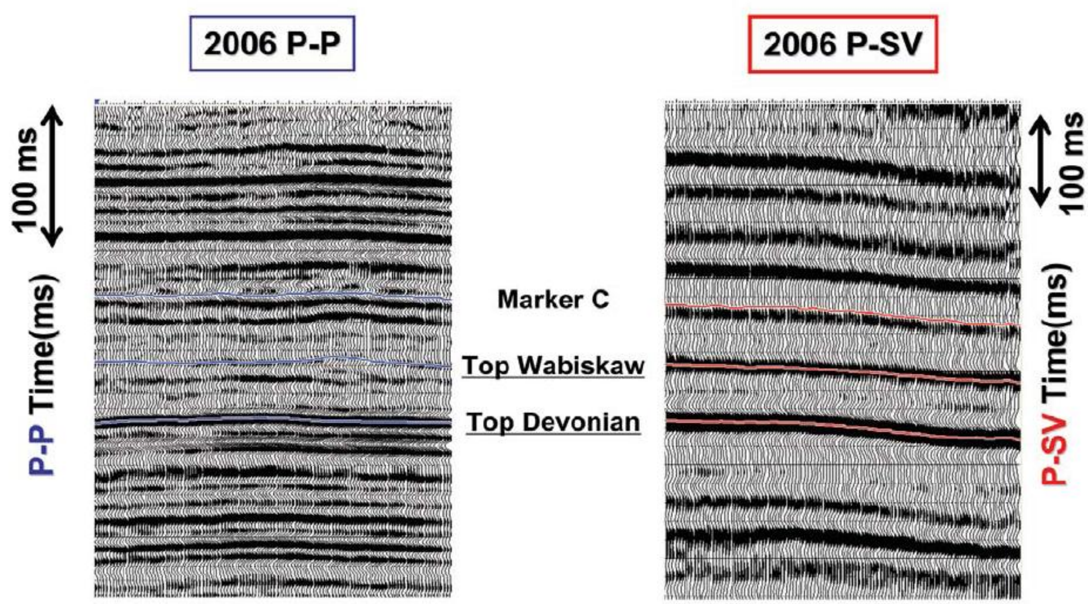

Figure 3. Example of the PP and PS time sections in the study area (from Nakayama et al., 2008).

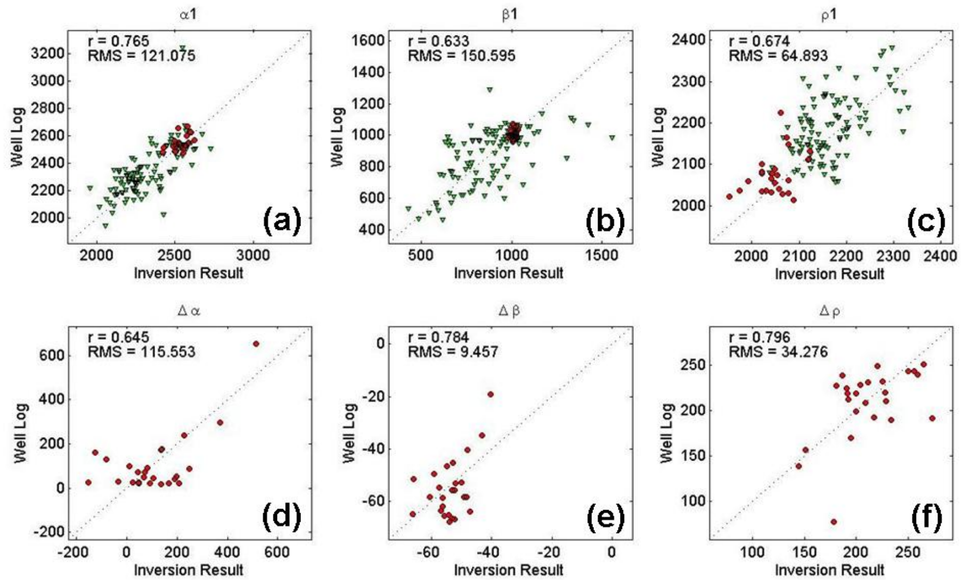

Figure 4. Comparison between inversion result and well log for PP alone inversion with S/N ratio being 2. X- and Y-axis is inversion result and well log, respectively. (a),(b), (c),(d),(e), and (f) are for α, β, ρ, Δα, Δβ, and Δρ, respectively. All units are in MKS system. The circle and triangular represents for reservoir layer and layer above it, respectively.

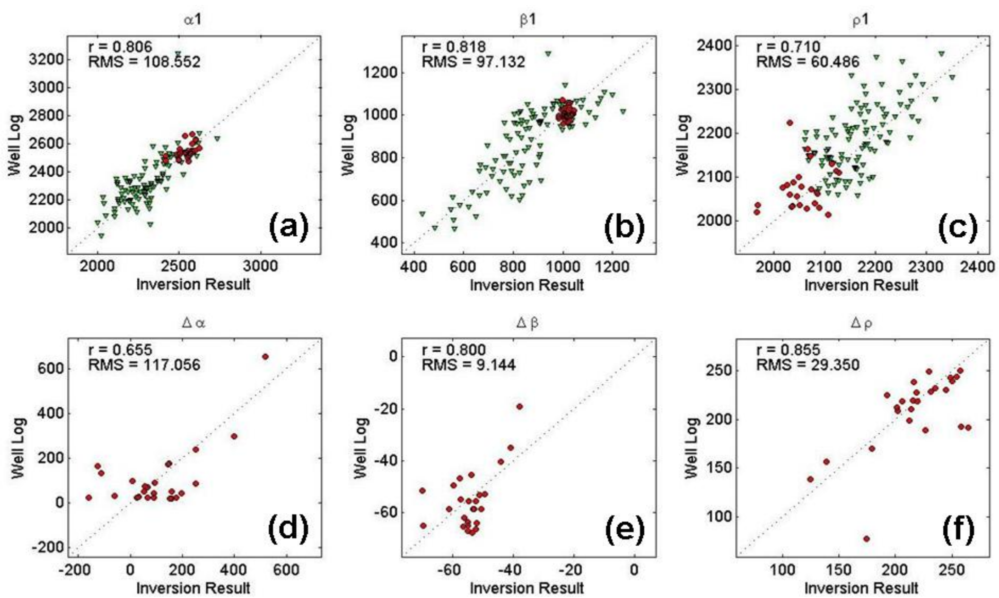

Figure 5. Same as Figure 4 except for joint inversion of PP at baseline and PP & PS at monitor survey.

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