Anisotropic stress field characterization for caprock integrity in the Athabasca Oil-Sands
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Summary
Caprock integrity is a critical safety issue oil-sands reservoirs, during thermal production with steam-assisted gravity drainage (SAGD). We present a method for in-situ anisotropic stress field characterization in the Clearwater Formation, which represents the caprock for the two Athabasca oil-sands reservoirs studied. The geomechanical parameters derived from seismic data are integrated with knowledge obtained from dipole sonic logs about formation’s anisotropy.

A key point in this method is the estimation of the normal fracture weakness parameter based on constraints on the compressional velocity of the intact rock, under the assumption of horizontal transverse isotropy. The constraints were necessary because not all the elastic moduli can be recovered using only density, compressional, and fast and slow shear wave data recorded in a borehole.

The minimum (σ₀n), and maximum (σ₀H), horizontal stress were then expressed as a combination of the normal fracture weakness, Lamé parameters (incompressibility λ and shear modulus μ), and the vertical stress. The two principal horizontal stresses were further used to evaluate the differential horizontal stress ratio.

Comparisons of minimum horizontal stress obtained from this method, with in-situ minimum horizontal stress estimated from injection testing at several wells, showed a very good consistency, with less than 0.3 MPa differences. Further away from the wells, the principal horizontal stresses (maximum and minimum) were predicted using Lamé parameters seismic volumes determined from PP-PS prestack inversion analysis. The differences between seismic and mini-frac estimations of minimum horizontal stress were within 0.05-0.6 MPa.

The estimated stress field compared well with results from the amplitude variations with azimuth (AVAZ) inversion analysis. For example, the large differential horizontal stress ratio areas show high fracture density, and the fractures that are locally confined to areas of high stress ratio are oriented parallel to the direction of the regional maximum horizontal stress.

Introduction
In the Athabasca oil-sands, the reservoir caprock consists of Cretaceous shale successions of the Clearwater Formation, which is overlain by the sand-dominated deposits of the Grand Rapids Formation. The quality of the caprock seal is very important, as it needs to block the vertical migration of the steam and to confine the stresses and the deformations induced during the oil recovery process through SAGD technology. Therefore, knowledge of existing fracture networks and the stress state of the caprock is critical for resource development.

Estimation of in-situ anisotropic stress
Rock elastic anisotropy can have a variety of causes, including unequal stresses and mechanical defects (Crampin, 1984). In general, it is believed that the fracture-induced anisotropy is the major cause of the observed anisotropy, but observations on stress-induced anisotropy suggest that initially isotropic materials become anisotropic when they are subjected to large stresses. The separation between the two is very difficult, but in general, anisotropy of less than 5-8% is attributed to stress, and anisotropy with higher values is attributed to discontinuities. However, this is not entirely true as it is known that fractures develop even at low stresses (Liu and Martinez, 2012).

Schoenberg and Sayers (1994) showed that, under the linear slip deformation assumption, the effective stiffness matrix for a horizontally transversely isotropic (HTI) fractured material have components from the unaltered rock (the background moduli λ and μ), and components of the fractured rock (the normal and tangential fracture weaknesses δₙ and δₜ). The fracture weaknesses are dimensionless parameters with values between 0 and 1, relating the normal and shear excess compliances, due to fractures to the total compliance of the fractured medium.

Thomsen (1986) estimated the horizontal stress in a medium with a vertical symmetry axis (VTI), based on: 1. the elastic stiffnesses and the vertical stress, and 2. the vertical P- and S-wave velocities along with a correction for anisotropy through the anisotropy parameter δ.

Schoenberg and Sayers (1994) elastic stiffness matrix for a fractured material with HTI symmetry was used by Gray et al. (2012) who formulated the two horizontal stresses as functions of Young’s modulus, Poisson ratio, vertical stress, and a fracture parameter called normal fracture compliance.

Geological indicators for the magnitude and orientation of minimum in-situ stress at wells are provided by mini-frac testing, in which a small volume of fluid is injected into the formation to create a fracture. Because the hydraulic fracture opens perpendicular to the lowest in-situ stress, its direction indicates how the minimum stress is oriented. The analysis of recorded injection rate, pressure and pressure falloff also permit the determination of minimum stress magnitude and formation pore pressure at the well.
Anisotropic stress field characterization for caprock integrity in the Athabasca Oil-Sands

Petrophysical analysis of the dipole sonic logs within the oil-sands area indicate that shear-wave splitting occurs within the Clearwater Formation, suggesting that the medium is azimuthally anisotropic. The simplest symmetry of such a medium is horizontal transverse isotropy, characterized by five independent parameters. This is why, in this paper, we adapted Thomsen’s (1986) approach for the calculation of stress in a VTI medium, to a medium with HTI symmetry. The assumption that crustal rocks behave linearly elastic under uniaxial strain (Hubbert and Willis, 1957) is part of the presented method. Expressions for minimum and maximum horizontal stresses ($\sigma_h$ in equation (1) and $\sigma_H$ in equation (2)), and their differential ratio (DHSR in equation (3)) were derived based on the stiffness coefficients, the Lamé constants and the normal fracture weakness (assuming that the symmetry axis is parallel to the $x_1$-direction).

\[
\sigma_h = \frac{C_{13} \sigma_v}{C_{33}} = \frac{\lambda_h(1-\delta_N)}{(\lambda_h+2\mu_h)(1-\lambda_h/\delta_N)(\lambda_h+2\mu_h)} \sigma_v 
\]

\[
\sigma_H = \frac{C_{13}-2C_{44}}{C_{33}} \sigma_v = \frac{\lambda_h(1-\delta_N)}{(\lambda_h+2\mu_h)(1-\lambda_h/\delta_N)(\lambda_h+2\mu_h)} \sigma_v 
\]

\[
\text{DHSR} = \frac{\sigma_H - \sigma_h}{\sigma_H} = 1 - \frac{(1-\delta_N)}{1-\lambda_h/\delta_N} 
\]

However, the stiffness coefficient $C_{13}$ and the normal fracture weakness $\delta_N$ in the stress expressions are usually unknown, or difficult to solve for. Only the $C_{33}$, $C_{44}$, and $C_{55}$ coefficients, which are related to the vertical P-wave and the two vertical S-wave modes can be obtained from dipole data. Measurements of the fast and slow S-wave velocity only allow the direct estimation of the tangential fracture weakness $\delta_T$. To obtain the rest of the parameters, a different approach is needed. In our method, sections of the well logs without shear-wave splitting were used to derive information about the velocity of the background rock. The practical implementation (Figure 1) consists of: 1. averaging the density, P-wave velocity, and fast and slow S-wave velocity logs, using isotropic Backus (1962) averaging technique for the entire Clearwater Formation interval; 2. determining the elastic stiffnesses $C_{33}$, $C_{44}$, and $C_{55}$, and the fracture weakness $\delta_T$; 3. inferring the background P-wave velocity from log sections where the fast and slow shear-wave velocities are similar; and 4. estimating the fracture weakness $\delta_N$ and the $C_{13}$ and $C_{11}$ stiffness coefficients.

Two methods were developed and tested to estimate the stresses (Figure 2): 1. the stiffness coefficients method (SCM), applicable for log data, and 2. the Lamé constants method (LCM), applicable for both log and seismic data. For seismic data, the density and Lamé constants volumes can be estimated through joint PP-PS prestack inversion analysis.

Figure 1: Workflow used to estimate the elastic stiffnesses and fracture weaknesses using density, P-wave and fast and slow S-wave sonic logs within the caprock.

Figure 2: Stress estimation workflow consisting in recovery of the stiffness matrix and calculation of vertical and horizontal stresses using either the elastic stiffness coefficients (SCM) or a combination of the elastic moduli and normal fracture weakness (LCM).

The dependence of horizontal stresses on the background moduli allow for 3D seismic stress field estimation in the
Clearwater Formation of the oil-sands reservoir. The vertical stress was estimated by multiplying the gravitational acceleration (g) with the integrated density over increasing depth.

Applications on the Clearwater Formation within the Athabasca Oil-Sands

The proposed method was applied for the caprock characterization within two Athabasca Oil-Sands areas. The density, P-wave and fast and slow S-wave velocities logs were averaged within the interval between the top of the Clearwater Formation and the Wabiskaw Marker, by using Backus isotropic averaging method.

Within the first area, 12 dipole logs were analysed, with two of the wells being outside of the seismic survey. At each well, the tangential fracture weakness was estimated from the averaged slow and fast S-wave velocity, and then the normal fracture weaknesses were determined using the previously described method. The effect of fracture δN on the minimum horizontal stress was investigated by calculating σh based on the SCM where δN is based on: 1. individual values, 2. regression estimates, and 3. averaging values. Results were compared with in-situ mini-fracture measurements of σh (Figure 3).

Figure 3: Estimation of σh with SCM, and comparison with mini-frac (MF) data. Results are at the top of Clearwater C Shale, in MPa.

Generally, σh results - based on regression estimates and average of fracture δN - were consistent with the results from injection tests. Well 5 shows underestimated σh when using the individual fracture δN calculated at the well, but comparable σh magnitudes when using the average or regression values, indicating that inconsistencies arising from well data analysis have an important effect on the accuracy of estimations. Significant differences between all four estimations remained at Well 3. The magnitudes obtained for all principal stresses (σv, σh, and σH) at ten wells using δN regression data are shown in Figure 4.

Figure 4: Magnitudes of principal stresses in MPa obtained at the top of Clearwater C Shale (vertical stress in blue, minimum horizontal stress in orange, and maximum horizontal stress in grey). The relative magnitude of principal stresses indicates a normal faulting regime (maximum principal stress is vertical).

For the second study area 7 dipole wells were available for analysis. Of these, only one well (Well 4) had mini-frac data but 3 more wells had stress tests available. The principal stresses were calculated at each of the seven wells using both stiffness coefficients and Lamé constants methods, and then within the 3D volume by using the density and Lamé constants seismic volumes obtained from PP-PS prestack inversion analysis, and an average fracture weakness δN. Figure 5 shows the spatial variation of the three principal stresses at the Clearwater C Shale surface.

Figure 5: Lateral variation of the vertical stress (top), the maximum horizontal stress (centre), and the minimum horizontal stress (bottom) (in kPa) indicate a normal faulting regime at the Clearwater C Shale surface. Dipole sonic wells and mini-frac data are indicated by D and MF, respectively.

Examples of σh obtained from various methods at wells are shown in Figure 6. Generally, the solutions obtained from seismic estimation of stress compared very well with mini-frac records. Particularly, Well 10 is very well resolved, with a minimum horizontal stress of 5.29 MPa estimated from seismic, and a value of 5.24 MPa recorded during the injection tests.
Anisotropic stress field characterization for caprock integrity in the Athabasca Oil-Sands

Figure 6: Comparative analysis of the minimum horizontal stress magnitudes at the Clearwater C Shale surface, calculated using log estimation based on stiffness coefficients and Lamé constants methods (SCM and LCM), seismic estimation using Lamé constants method, and mini-frac tests (MF). D indicates dipole wells. Seismic estimations of $\sigma_h$ show a good agreement with estimations from mini-frac tests.

The anisotropic stress estimation at Well 4 is illustrated in Figure 7.

Figure 7: Stress logs and seismic at Well 4. $\sigma_h$ and $\sigma_H$ logs were calculated using stiffness coefficients method (red), and Lamé constants method (blue). Black curves are exported traces from the seismic stress cubes, and red dot is the mini-frac discrete value. Vertical seismic sections through the stress fields at Well 4 are shown on the right, with red line indicating well location.

In parallel, an amplitude variation with azimuth (AVAZ) inversion analysis was performed using the Fourier coefficients method (Downton et al., 2011). The composite image in Figure 8 shows a remarkable similarity between the magnitude and orientation of anisotropy, represented by the size and direction of plates, and the differential horizontal stress ratio at the Clearwater B surface. A linear, almost continuous high anisotropy anomaly characterized by clustered fractures striking perpendicular to its longitudinal axis, seems to be dividing into two branches in the south-east corner of the study area. These fractures are also aligned parallel to the average NE-SW orientation consistent with the present-day regional maximum horizontal stress. Interestingly, along this trajectory are located three wells with the highest tangential fracture weakness or the highest fracture density. The DHSR shows a significant resemblance with the anisotropy anomalies, with values above 8% coinciding with high anisotropy.

Figure 8: Composite image showing the anisotropy and horizontal stress ratio anomalies at Clearwater B surface. The size and orientation of plates are related to the fracture density and direction, and the background surface is the differential horizontal stress ratio for which values less than 8% are represented in blue, and higher than 8% in red.

Conclusions

A new method to characterize the anisotropic stress field at well locations and within a 3D seismic survey, based on seismic data and velocity anisotropy observed in well logs was presented. Horizontal stresses were derived as functions of normal fracture weakness, vertical stress, and Lamé constants of the unfractured matrix, under the assumption of HTI symmetry.

Material complexity within the Clearwater Formation and limited measurements make caprock characterization very difficult when only dipole sonic wells are available. Therefore, the elastic stiffness matrix was recovered by inferring the background P-wave velocity from log sections without shear-wave splitting.

Regression estimates of $\delta_N$ provided the highest accuracy predicting the magnitudes of minimum horizontal stresses, when compared with stress tests.

Principal stresses were estimated within the 3D volume using density and Lamé seismic volumes from PP-PS prestack inversion analysis. High similarities were observed between anisotropy derived from amplitude variation with azimuth inversion analysis and stress ratio anomalies, with the largest anisotropy magnitude occurring in areas of high differential stress ratio, and smaller magnitudes being tied to smaller ratios.

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EDITED REFERENCES
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REFERENCES