

Interpretation of 3D multicomponent seismic data for investigating natural fractures in the Horn River Basin, northeast British Columbia

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ABSTRACT

A 3D multicomponent seismic dataset from the Horn River Basin was assessed for mapping fractures. The data had good fold, offset and azimuth distributions and several approaches were used to interpret the distribution of natural fractures. In addition to amplitude mapping, PP and PS curvature maps enhanced the structural interpretation of the data and enabled the lateral continuity of faults and fractures to be mapped across the area of the seismic survey. Both horizon and volume based most negative curvature were effective in mapping fault and fracture trends within both Exshaw and Muskwa shale gas targets. At the Exshaw level, the curvature shows two main fault trends: northwest-southeast trending normal faults that dip toward the southwest, as well as northeast-southwest strike-slip faults. At the Muskwa level, the curvature image shows different major fault trends, namely north, northeast-south, southwest (normal and reverse faults), and northwest-southeast faults. Fractures interpreted using curvature attributes are close to the major faults and their dominant trends are generally parallel to the major faults in the area.

INTRODUCTION

Shale gas is one of the three types of unconventional gas plays that are growing rapidly in North America (Kuuskraa and Stevens, 2009). What make this play attractive to the oil companies compared with conventional resources is that the shale gas formations are continuous over large areas, with giant reserves, and the gas is enclosed within microporosity of the shales, and the rocks, in this case act as source, reservoir and trap at the same time (Kuuskraa and Stevens, 2009). The challenge in this play is how to flow the gas from these tiny pores. One of the current solutions to this problem is the use of the new drilling technology such as multi-pad horizontal wells and multi-stage hydraulic fracturing (Figure 1). For example, this technology helped to double the gas productivity of the Barnett shale field in Texas and make it the largest gas field in that state (Beaudoin and Shaw, 2009). However this technology alone is not enough for optimum exploration and development. More advanced multi-disciplinary specialized techniques such as spectrographic, petrophysical, geochemical and geophysical analysis are needed in order to get a detailed picture of the shale gas complexity and heterogeneity. Data integration of all these methods will help to minimize the cost of these horizontal wells by locating them in the optimum location (Beaudoin and Shaw, 2009).

The geophysical data investigated in this study was a 3D multicomponent survey which provided optimal fold, offset, and azimuth distribution with the goal to map natural fracture orientations and density within these shale units. Acquiring converted-wave P-S data can provide lithological information and possibly detect fracture networks, whereas conventional P-wave data can reflect matrix and fluid characteristics (Stewart et al.,

2003). Wide-azimuth multicomponent data can provide several methods to detect fracture network. These are seismic attributes (e.g. coherency and curvature), P-wave azimuthal anisotropy, and shear-wave splitting (Jianming et al., 2009). Each method has its own limitations, however the integration of all these methods with well data will lead to better fracture prediction (Jianming et al., 2009).

This report is focused on the interpretation part of a recently acquired wide-azimuth 3C-3D dataset within the Horn River Basin, to map the shale gas reservoirs and predict its nature fracture orientation, and possibly density using seismic attributes.

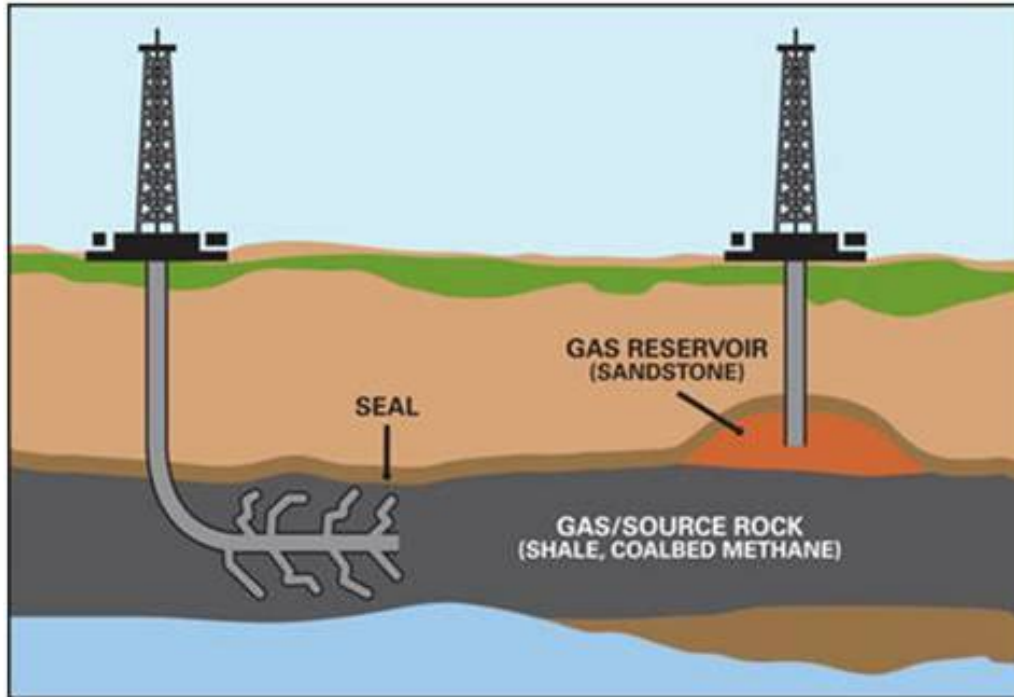


Figure 1: Multipad-horizontal drilling through the shale gas. Source: http://www.intragaz.com/en/geophysics_drilling.html

STUDY AREA

In Canada, the Horn River Basin, which is located in northeast of British Columbia (Figure 2), is the area where this shale gas play is being explored. The areal extent of this basin is about 1.28 million hectares and the estimated total gas-in-place is 500 trillion cubic feet (Beaudoin and Shaw, 2009). Intensive core analysis was carried out by CBM Solutions Ltd., for the British Columbia Ministry of Energy and Mines, Oil and Gas Division, Resource Development and Geoscience Branch to highlight the gas shale potential in the area (British Columbia Ministry of Energy and Mines and CBM Solutions, 2005). The analysis was focused on four properties that are important characteristics in each shale gas play. These are the total organic carbonate content, the thermal maturity, sorption capacity, and the mineralogy. The result of this study is shown on Table 1, and it designates the potential shale gas reservoirs (British Columbia Ministry of Energy and Mines and CBM Solutions, 2005). These targets are the Upper

Devonian/Lower Mississippian Exshaw shale and the Muskwa shale member of the Middle Devonian Horn River Basin Formation (Figure 3).

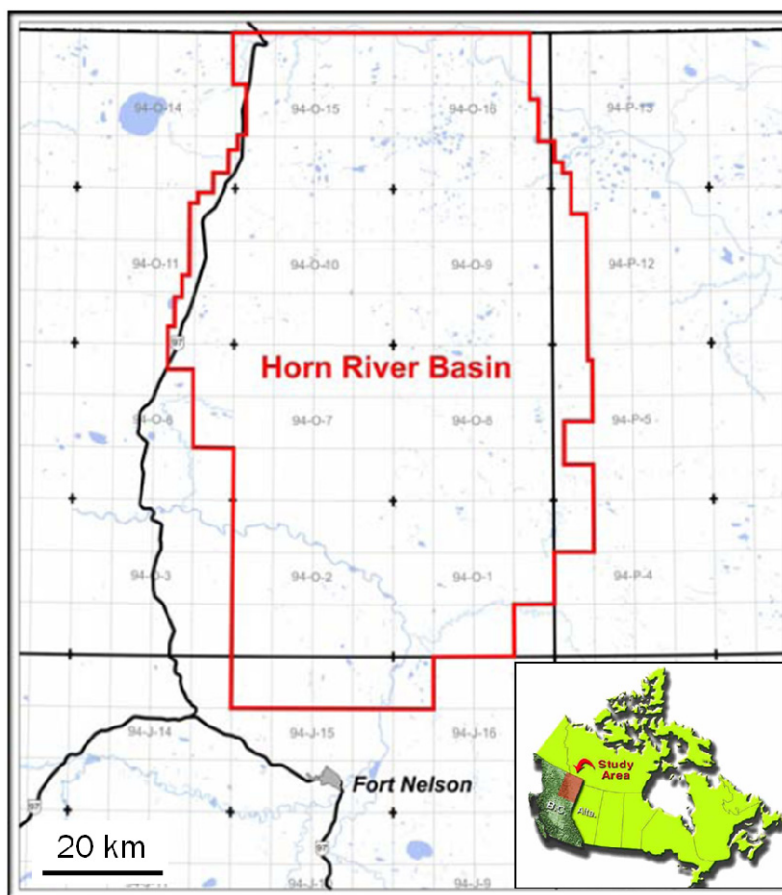


Figure 2: Location and limits of the Horn River Basin (highlighted in red), which is located in northeast British Columbia.

Source: http://www.northernrockies.org/Departments/Leg_Admin/Bulletin_Board/HRB%20Symposium/HRB%20FAQ2.pdf

Geologic setting

A stratigraphic column of northeast British Columbia is presented in Figure 3. The Devonian-Mississippian strata of northeast of British Columbia is interpreted to be deposited in ramp and basin settings (Richards, 1989). The shaly units represent the basinal deposits (e.g. Besa River, Exshaw, and Muskwa shales), while the carbonate units represent the ramp deposits (e.g. Slave Point, Trout River, and Kotcho carbonates) (Figure 2). The Exshaw and Muskwa shales are thin and present throughout the basin. They are characterized by high gamma ray reading on the logs due to their high organic content (British Columbia Ministry of Energy and Mines and CBM Solutions, 2005). The vertical thickness of the Exshaw Formation is from 5 to 15 meters and the Muskwa Formation is around 25 to 50 meters based on the wells that penetrated these formations on the study area. The Exshaw Formation can be found over a depth range between 1105-1120 m and the Muskwa can be found at a depth of around 2175-2250 m. Structurally, the area was subject to north-south extension followed by a compressional period at the

pre-Proterozoic sediments time which resulted in erosion of these sediments towards the southeast (Ross and Stephenson, 1989). At late Paleozoic time, two main fault trends were documented in the area: northwest-southeast trending normal faults that dip toward the southwest and linked in depth with a detachment fault (McClay et al., 1989), and northeast-southwest transverse faults that are associated with compression (Churcher and Majid, 1989) (Figure 4).

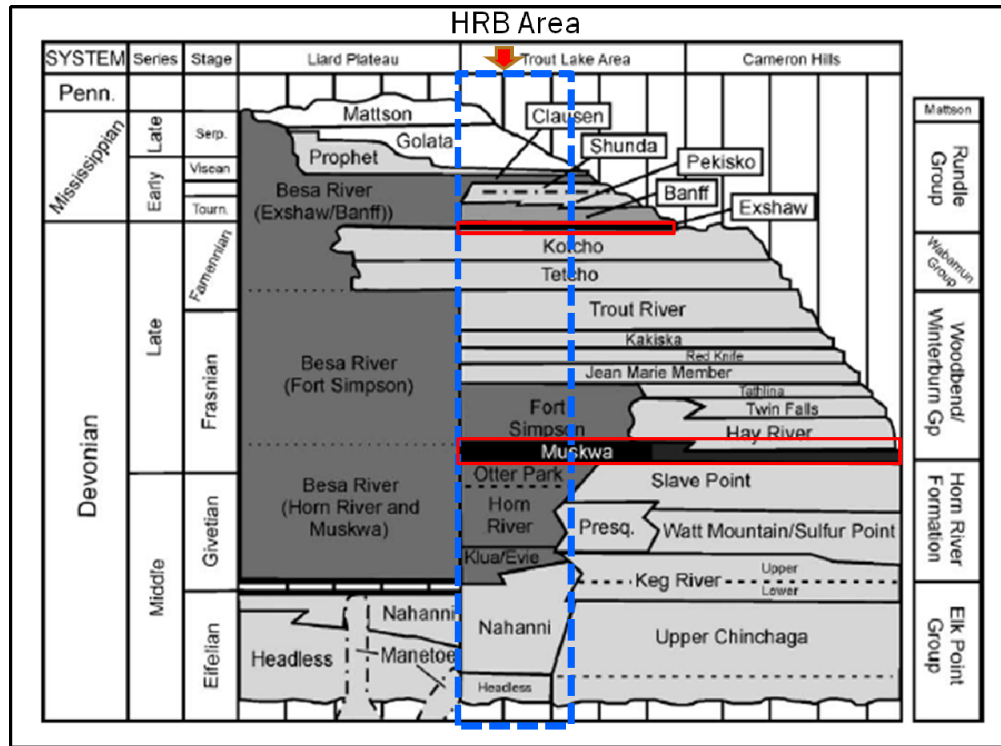


Figure 3: Stratigraphic section of Devonian-Mississippian strata in northern British Columbia. Dashed blue lines show Horn River Basin stratigraphy and the red solid boxes highlight the Exshaw and Muskwa shale reservoirs (Ross and Bustin, 2008).

Formation	# of Core Wells	Average Thickness (m)	Average TOC (wt%)	Average Porosity (%)	Mineralogy	Average Gas Capacity at 11 MPa (cc/g)
Exshaw	4	5-10	5.0	4.4	Quartz, Kolinite, Illite	1.3
Besa River	2	450-500	4.3	4.6	Quartz, Kolinite, Illite	0.8
Fort Simpson	3	475-525	0.4	3.3	Quartz, Kolinite, Illite	0.3
Muskwa	8	15-25	3.1	3.2	Quartz, Kolinite, Illite	0.7

Table 1: Summary data for each formation analyzed. The solid red rectangles indicate the main shale gas reservoir on the HRB (British Columbia Ministry of Energy and Mines, 2006).

During Cretaceous-Eocene time, the area was subject to a compressional regime that reactivated old normal faults above a deep detachment in the Upper Devonian-Carboniferous section, forming thrust faults, related fault-bend fold and detachment folds (Eaton et al., 1999).

DATA AND SOFTWARE

Olympic Seismic Ltd acquired the 3D3C dataset that is used in this study. It was obtained as a multicomponent survey and was processed by Sensor Geophysical Ltd. The data were imported into the Kingdom Suite software and a synthetic seismogram was computed to tie the PP seismic volume to the formation tops at this stage. Seismic reflections were correlated to well formation tops first by applying the seismic datum, and then matching the P-wave and density logs. After that, a 35 Hz Ricker wavelet was convolved with the reflectivity log calculated from the density and P-wave logs to create a PP synthetic seismogram. Figure 5 shows the seismic-to-well tie and the correlation between synthetic seismogram and the PP seismic stack is quite good for shallow target (Exshaw shale, 0.82 seconds) and good at the deep target (Muskwa shale, 1.52 seconds). The Exshaw Fm. in this well is only 5 m thick and is characterized seismically by a strong peak that is tuned with the event from the top of Kotcho Formation below it (Figure 5). In comparison, the Muskwa shale is about 51 m thick, and is characterized seismically by a weak trough due to the low impedance contrast between the overlying Fort Simpson shale and the underlying Muskwa shale (Figure 5). Figure 6 shows the seismic-to-well tie for PS data. The correlation between synthetic seismogram and the PS seismic stack is good for Exshaw shale (1.128 seconds) and fair to good at the top of Muskwa shale (2.178 seconds). Seismically, the top of both Muskwa and Exshaw shales are characterized by relatively moderate peak.

INTERPRETATION

The PP and PS seismic data were interpreted on a workstation using Kingdom Suite software version (8.5). Seismic interpretations started after performing the well-to-seismic tie (Figure 5 and Figure 6). Figure 7 shows the ten key seismic horizons picked (from top to bottom). These are the tops of the Debolt Formation, the Banff Formation, the Exshaw Formation, the Tetcho Formation, the Trout River Formation, the Kakisa Formation, the Fort Simpson Formation, the Otter Park Formation (the Base of Muskwa Formation), the Evie, and the Lower Keg River Formation. All these seismic horizons were picked at every 40 inline and cross line spacing. After that, a 3D interpolation were performed for these picks for each seismic horizon using the 3D hunt feature that provided by Kingdom Suite. Figure 8 shows the two-way time structure maps for both top Exshaw Formation and the base of Muskwa Formation with interpreted faults intersecting them. Three normal faults dip southwest and their strike direction is northwest-southeast. Two probable strike-slip faults intersecting at 90° are interpreted at the top of Exshaw Formation in the middle of the survey (Figure 8). The interpretation is quite different in the deeper Muskwa Formation. One normal fault and one reverse fault have been interpreted at this level. The reverse fault dips northwest direction and trends northeast-southwest, forming a small four way anticline closure. The anticline axis is parallel to the strike direction of the fault (Figure 8). The normal fault has small throw and its direction is running north-south (Figure 8).

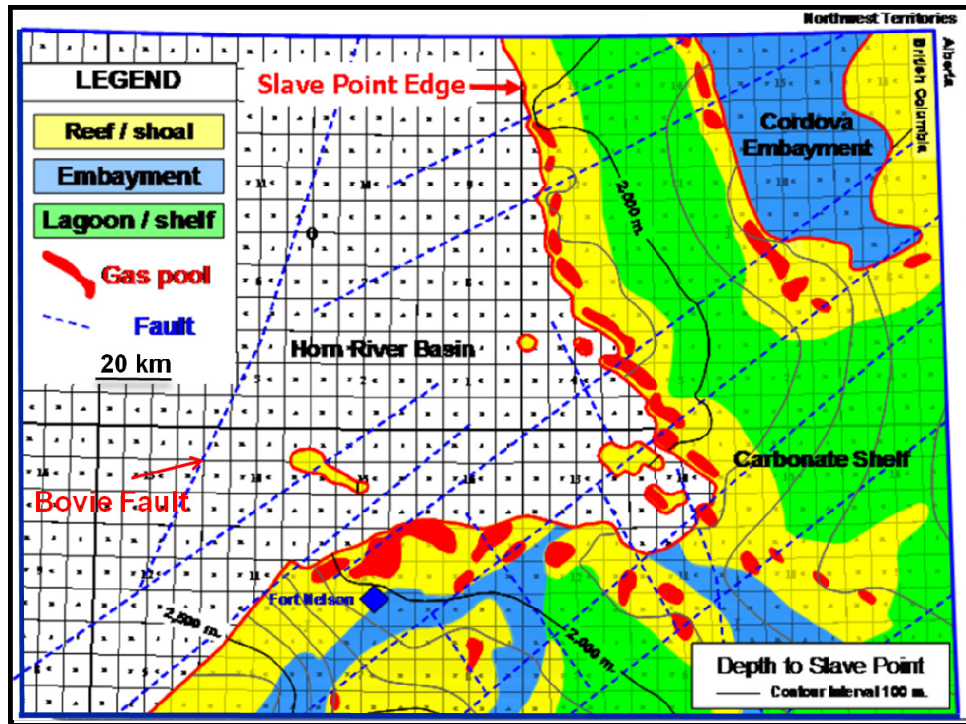


Figure 4: Map of the Slave Point Formation which is the base of the Muskwa Formation in the area of Horn River Basin. This map, shows the Bovie Fault and several other dominant faults that trend in the area (SW-NE and NW-SE) indicated by the blue dashed lines. Source: http://www.wcsbgroup.org/meetings/pdf/2009/Jurisdiction%20Updates/BC_Update%20and%20Shale%20Gas_Levson.pdf

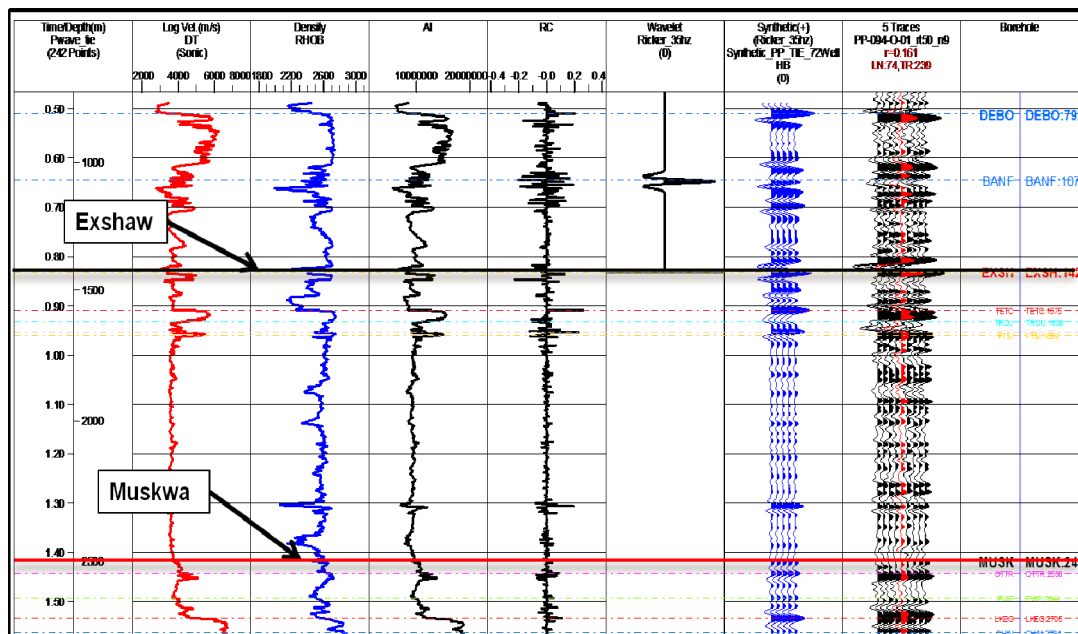


Figure 5: Seismic-well tie for PP data showing from left to right: Interval velocity (black), Sonic log (red), density log (blue), calculated impedance log (black), reflectivity (black), the 35 Hz Ricker wavelet, the synthetic seismogram with five traces (blue) and nine traces that have been extracted from the 3D dataset near the wellbore (black).

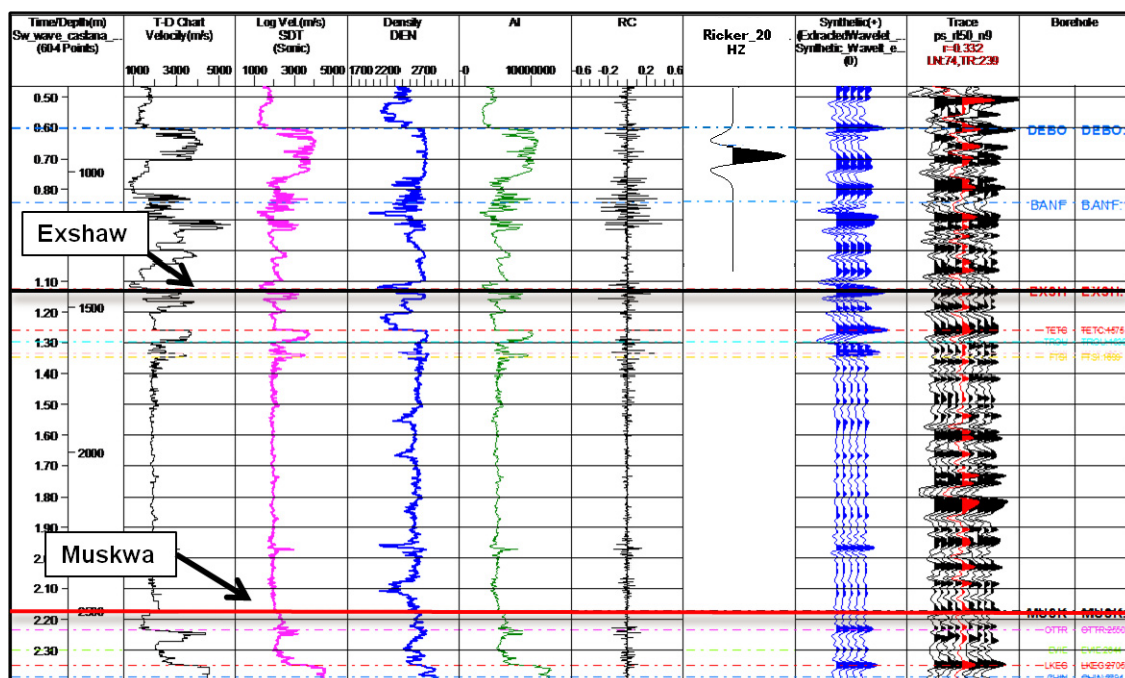


Figure 6: Seismic-well tie for PS data showing from left to right: Interval velocity (black), Sonic log (pink), density log (blue), calculated impedance log (green), reflectivity (black), the 20 Hz Ricker wavelet, the synthetic seismogram with five traces (blue) and nine traces that have been extracted from the 3D dataset near the wellbore (black).

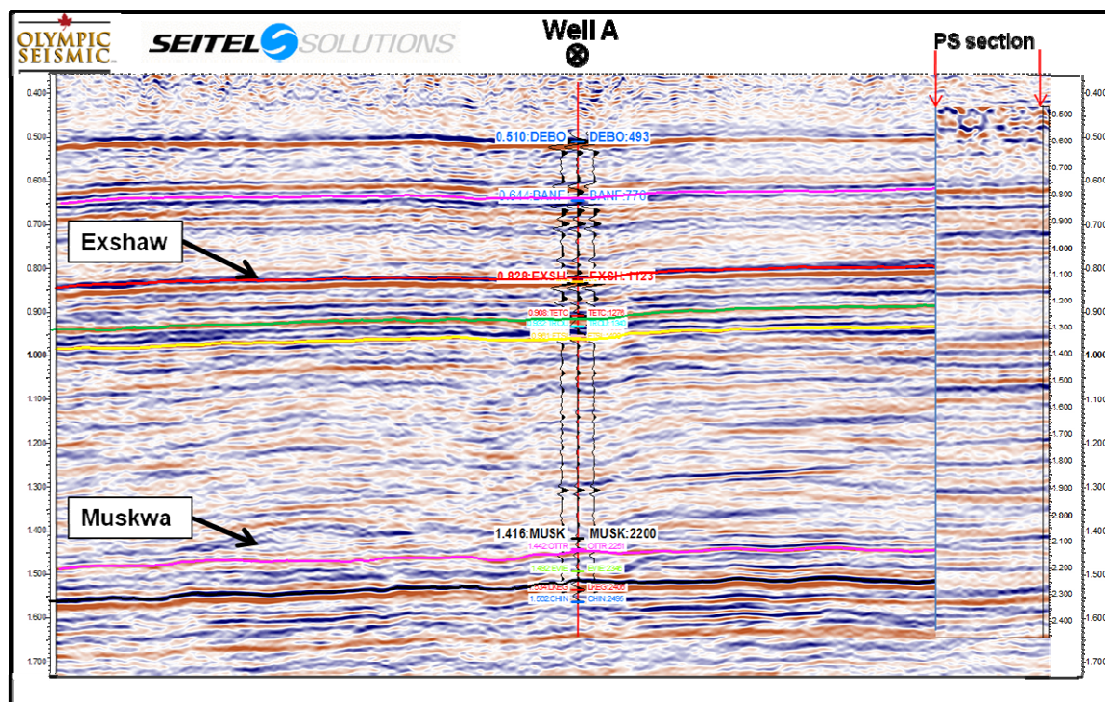


Figure 7: Inline from PP data showing the seismic-well tie for well A and the ten key interpreted seismic horizons. The two red arrows on the top right corner show the PS section correlated approximately with the PP data.

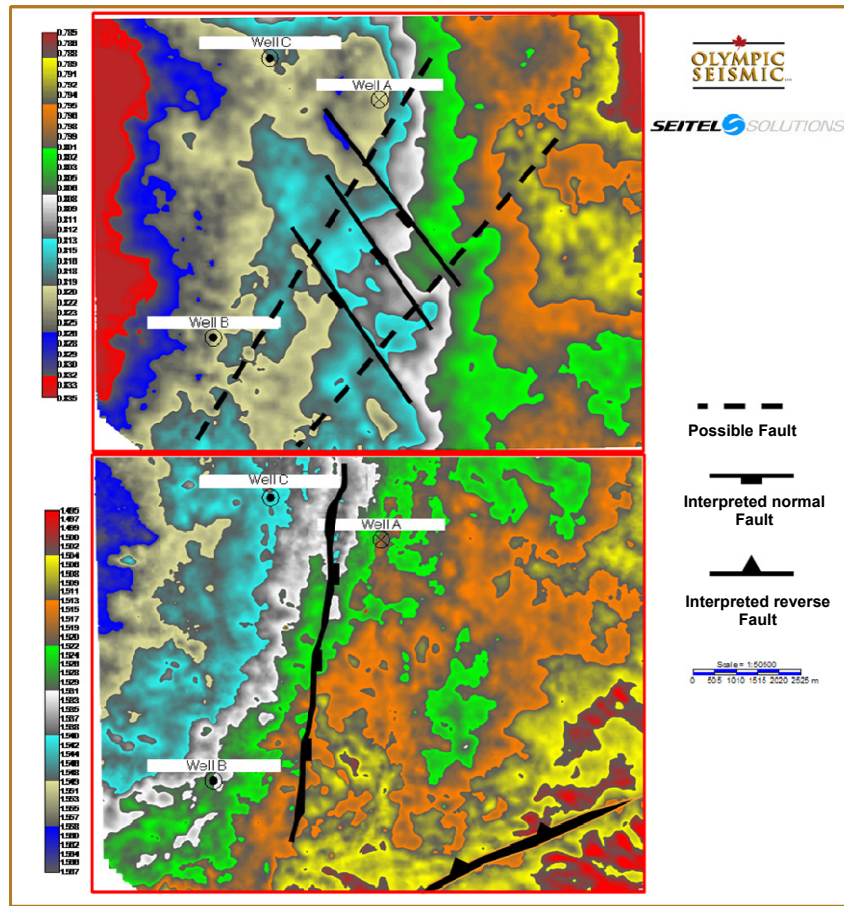


Figure 8: Exshaw shale two-way time structure map (upper) and base of Muskwa shale two-way time structure map (lower) showing the interpreted faults (black solid lines) that cut these surfaces in the area.

CURVATURE ANALYSIS

Recently, the curvature attribute have been used to recognize subsurface geological features such as faults/fractures and channels (Chopra et al., 2006). Mathematically, it is the computation of the second order derivative of the curve (Chopra et al., 2006). In 2-D curve, it is the reciprocal of the radius of a circle that is tangent to the curve at any point on it (Figure 9a) (Chopra et al., 2006). While in 3-D, the curvature analysis can be computed by applying the same curvature in 2D analysis on the intersections of two orthogonal planes with the 3D surface (Figure 9b) (Chopra and Marfurt, 2007). This computation can be made on two scenarios:

- 1- Horizon based
- 2- Volumetric based

Since the volume-based curvature is computed from a time window of seismic data, the results are statistically less sensitive to backscattered noise and has a higher signal-to-noise ratio than horizon-based curvature (Chopra and Marfurt, 2007). Horizon based computations require high quality seismic data and a strong impedance contrast on the

horizon of interest, whereas volume-based curvature do not need a picked horizon to do the analysis (Chopra and Marfurt, 2007).

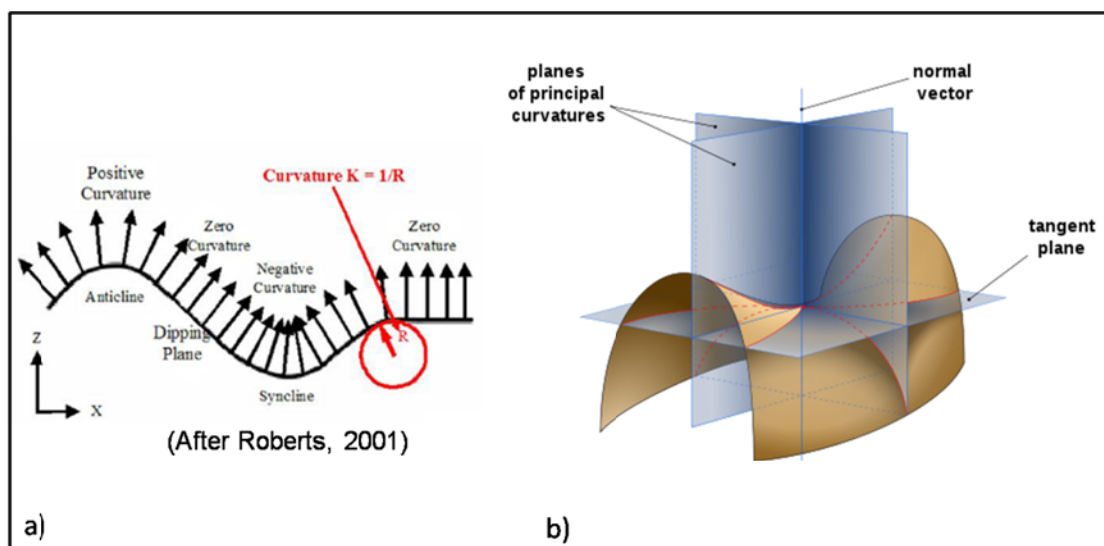


Figure 9: (a) 2D curvature of a line. Sign convention for curvature attributes: Positive for anticline shape, negative for syncline shape, and zero for horizontal shape. (b) Showing the two orthogonal set that intersect with the 3D surface. Source: <http://en.wikipedia.org/wiki/Curvature>

Both analyses were calculated on the 3D data and the results are shown in Figures 10, 11, 12 and 13. Figure 10a shows the horizon-based most negative curvature for the top of the Exshaw horizon which shows the three normal faults, indicated by the blue arrows, the two possible strike-slip faults indicated by the white arrows as well as interpreted acquisition footprint throughout the survey area highlighted by the red ellipses. Figure 10b shows the 0.894 second time slice of the volume-based most negative curvature computed on the PP volume, which shows the three normal faults indicated by blue arrows, as well as the two possible strike-slip faults indicated by white arrows. Figure 11a shows the 1.208 second (Exshaw Formation) volume-based most negative curvature computed on the PS volume, which shows the three normal faults indicated by blue arrows. It also shows two features that are believed to be artifacts generated by a significant channel system within the near surface indicated by white arrows. These subsurface channels are shown in refraction bedrock map (Figure 11b).

Figure 12a shows the computed horizon-based most negative curvature for the base of Muskwa horizon which shows the two major faults at this level, indicated by the black arrows. The computed volume-based most negative curvature at the level of the base Muskwa shale, represented by the 1.52 second time slice is, shown in figure 12b. It shows clearly the two major faults cutting this section indicated by black arrows and circular features which possibly interpreted to be mounds or karsting, indicated by white arrows. These featured is not mapped by the horizon-based attribute Figure 12a.

Fracture detection using seismic amplitude data is a very challenging task due to the limitation in the frequency bandwidth which reduces seismic resolution. Despite the fact

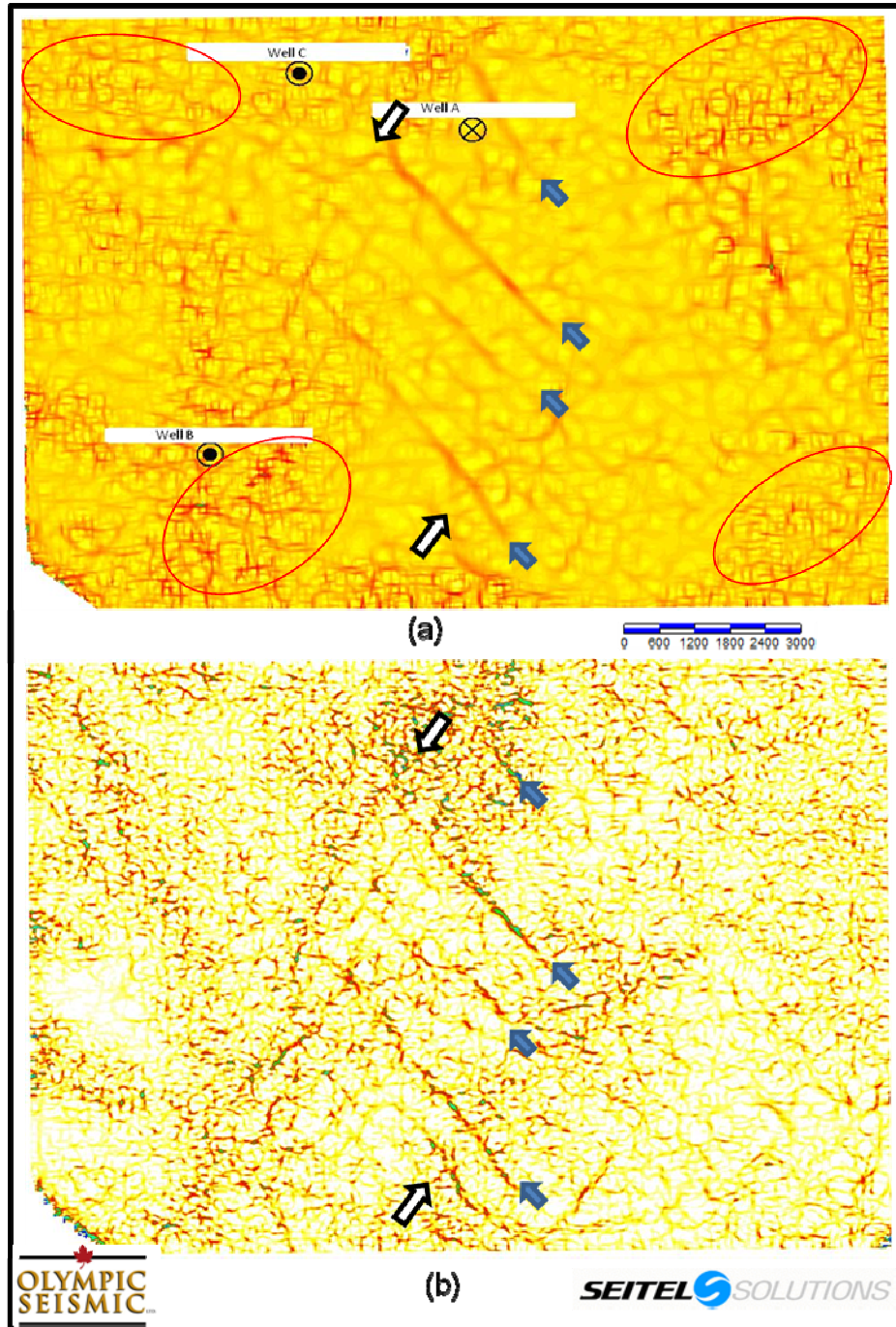


Figure 10: (a) Horizon-based most negative curvature for the top of Exshaw horizon (b) 0.894 second time slice of the volume-based most negative curvature computed on PP volume. Red ellipses indicate acquisition footprint. The blue arrows show the three normal faults and the white arrows show the two possible strike-slip faults.

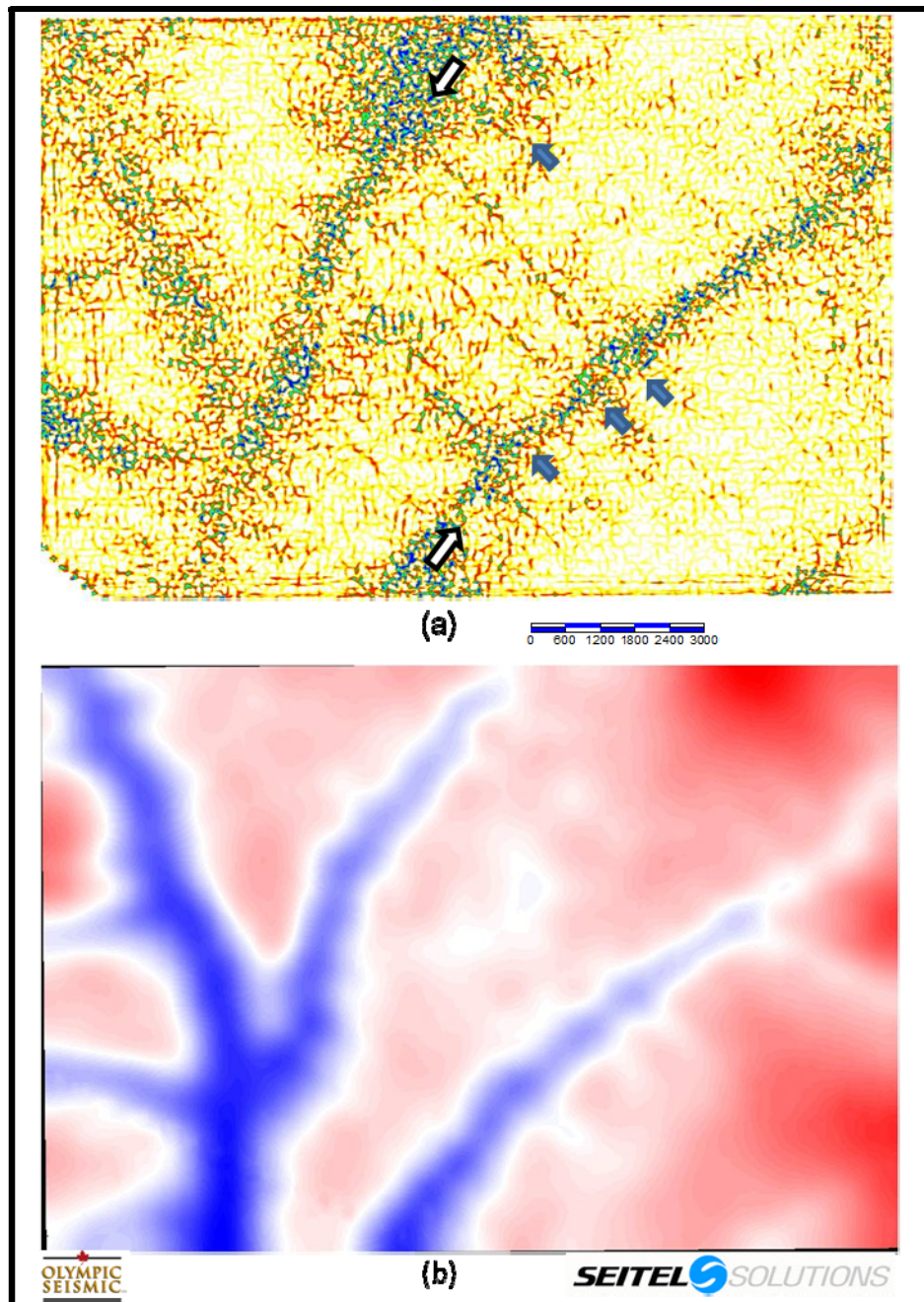


Figure 11: (a) 1.208 second volume-based most negative curvature computed on PS volume (b) base of weathering map.

that fracture is a sub-seismic geological feature, curvature, particularly the computed volume-based most negative curvature, is interpreted to delineate fracture systems. Their signature appear in this attribute analysis as a relatively medium to high negative curvature value. In this case study, zones of natural fractures are mainly detected close to the major faults (Figure 10b, 12b and 13). The dominant trends of these fractures are generally parallel to the major faults in the area (Figure 13).

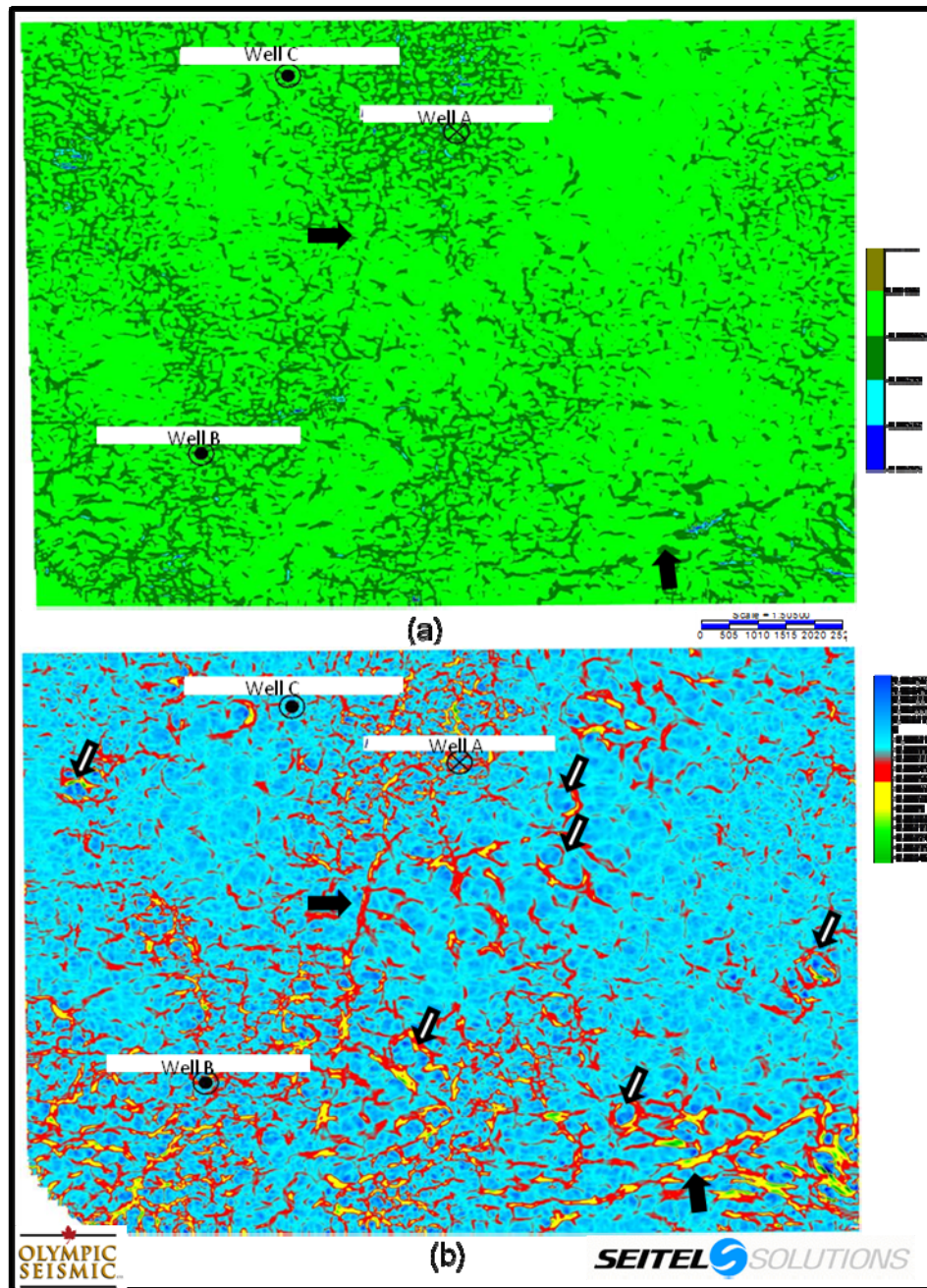


Figure 12: (a) Horizon-based most negative curvature for the base of Muskwa horizon (b) 1.52 second time slice of the volume-based most negative curvature computed on PP volume. The black arrows indicate the two major faults and the white arrows show circular features which possibly interpreted to be mounds or karsting.

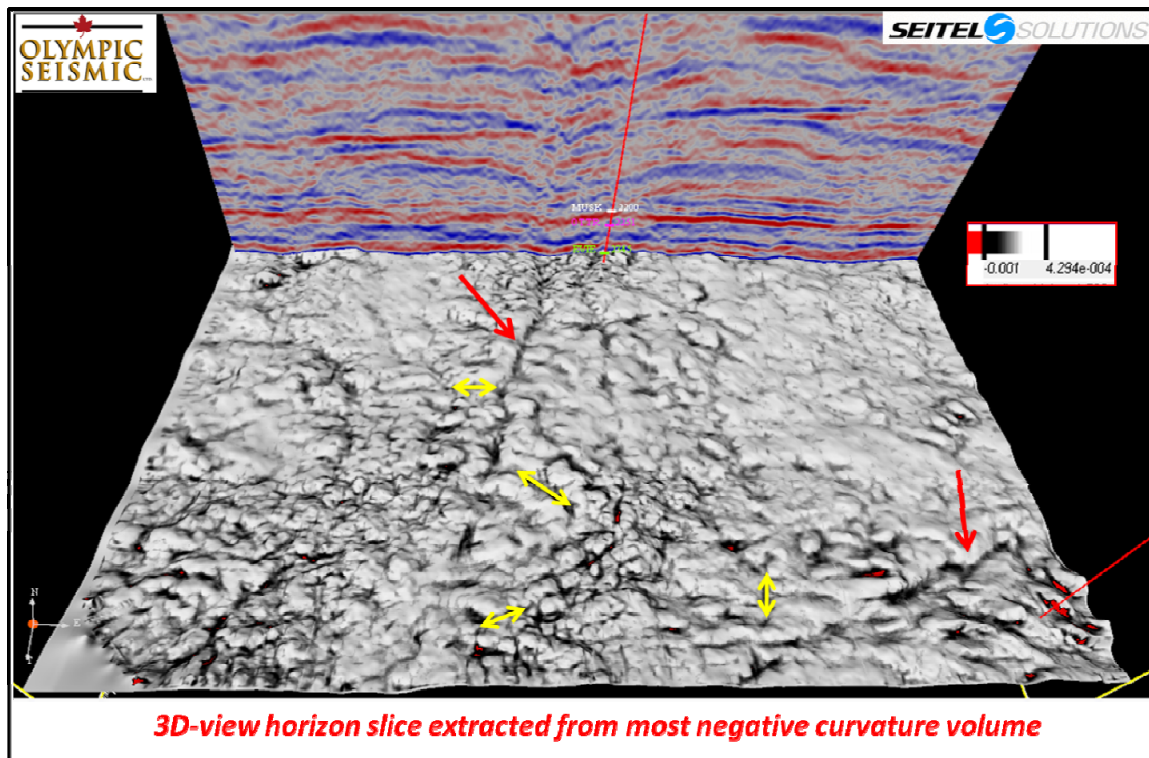


Figure 13: Horizon-slice through most negative curvature volume at the base of the Muskwa horizon shows the two major faults indicated by red arrows and the four fracture trends in the area highlighted in yellow arrows.

CONCLUSIONS

Curvature attribute analyses enhance the structural interpretations, such as faults and fractures and map their lateral continuity throughout the seismic volume. Both horizon and volume computed based most negative curvature have been used to map faults and fractures trends at both Exshaw and Muskwa shale gas targets. At the Exshaw level, the curvature shows two main fault trends: northwest-southeast trending normal faults that dip toward the southwest and northeast-southwest strike-slip faults. At the Muskwa level, the curvature image shows different major fault trends: north, northeast-south, southwest (normal and reverse faults), and northwest-southeast faults. The interpreted fractures using curvature attribute are those fractures that are close to the major faults and their trends are generally parallel to the faults.

FUTURE WORK

Future work includes calibration of P-wave and S-wave volumes with well information and to do analysis of full seismic attributes particularly interval V_p/V_s . Fracture detection using P-wave azimuthal anisotropy, and S-wave splitting will also be undertaken to integrate with curvature results.

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