Seismic Attributes for Fracture Delineation

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Abstract

Open natural fractures can enhance permeability in reservoirs and so result in improved productivity and recovery efficiency. For this reason, the location and characterization of more intensely fractured zones within a reservoir represent an important goal for many seismic investigations. Typically, individual fractures fall well below seismic resolution. Nevertheless, fracture sweet spots (and/or the coupled stress regime that opens micro-fractures or control hydraulically-induced fractures) can be detected using pre-stack attributes such as velocity versus azimuth and amplitude versus azimuth attributes. Alternatively, we can use post-stack seismic attributes to map faults, folds, and flexures, develop a tectonic deformation hypothesis, and test this hypothesis against image logs, tracer data, or other well control, allowing us to infer spatial locations where fracture density is high. In this talk, I will focus on this latter work flow, illustrating the information content available in properly analyzed surface seismic poststack attribute volumes.

Introduction

Fractures have always been important components of reservoir characterization, but the description and characterization of fractures in reservoirs has attracted increased interest in the last 15 years with the increased exploitation of tight sandstone and limestone reservoirs as well as resource plays such as shale gas and coal bed methane. Many, if not most of these reservoirs are now produced using horizontal wells. In addition to predicting sweet spots, or zones of greater fracture intensity, we also wish to predict fracture azimuths, thereby guiding our horizontal well to intersect as many natural fractures as possible.

Fractures are a direct result of stresses on the rocks. In nature, we observe that fractures may be related to tectonic deformation or to loading and unloading of the earth's surface. Since there are many different types of deformation styles and many different rock types there are many different types of fractures. Nelson (2001) notes that rocks can bend, fold, fracture, or fault. The fractures themselves may be classified according to morphological descriptions such as open, deformed, mineral-filled, or vuggy. The effect that fractures may have on completion and production behaviour is a function on the fracture morphology, such that an understanding of what kind of fractures may be present is critical. Whether the fracture morphology is going to be open, mineralized, deformed, or vuggy depends heavily on the rock brittleness, formation thickness, the history of burial, the type and rate of tectonic deformation, and diagenetic alteration. Which fracture subsets are open is a function of present day pore pressure and stress orientations. The word fracture defines a broad spectrum of discontinuities including faults that have displacement across them, joints, which have no displacement, and stylolites which may involve some dissolution or remineralization (Figure 1). Although we may encounter any general type of fracture, for our Western Canadian Sedimentary Basin, we commonly encounter fractures caused by compressional stresses, particularly shear fractures.

The shear fracture planes are at acute angles to the maximum compressive stress ($\sigma 1$) direction. We may also encounter joints, also called extension fractures, which will be oriented parallel to the maximum compressive stress. If the maximum compressive stress is vertical into the earth (due to the weight of the overburden), the extension fractures will be vertical, and the shear fractures will be at an acute angle to vertical. Deep, mildly folded targets will often be dominated by these types of fractures, although the direction of maximum stress may change depending where on the fold we are looking. Shear fractures will also commonly occur in a halo about faults, in orientations at acute angles to the fault plane.

Seismic attributes and fracture prediction

While the formal definition of fractures include faults, most practicing petroleum geoscientists (including the author of this paper) differentiate between faults with finite displacement (which they call "faults"), and faults that have offsets below the level of seismic resolution and are undifferentiable from joints, "fractures". Detection and evaluation of fractured reservoirs requires careful and planned efforts for such an objective as it entails significant time and cost implications. In their desire to keep the interpretation of seismic data simple and short, many geoscientists simply ignore the presence of these fractures in reservoirs.

Recent advances in 3D seismic data acquisition, processing and interpretation coupled with the application of new seismic attributes to good wide-azimuth, high-resolution P-wave and improved efficiencies in generating and recording multicomponent seismic data have greatly advanced our ability to map fractures from Earth's surface.

While fractures with little to no vertical offset are difficult to map on vertical seismic sections. They do cause changes in seismic wave propagation. Fractures may cause scattering of the incident seismic energy thereby attenuating the amplitude of higher frequencies. By measuring the frequency spectra of a time-window above and below the fractured zone, one can infer the presence of fractures.

When an arbitrarily polarized shear wave enters an anisotropic media such as a fracture zone, it splits into polarized shear waves – with the faster one travelling parallel to the fluid-filled fractures and the slower one travelling perpendicular to the fractures. This shear-wave splitting or birefringence phenomenon can be measuring the time-difference between the fast and slow shear waves within a layer, thereby yielding information on the density and orientation of fractures. Such applications require multicomponent data. Case studies have been published where the variation in oil production in horizontal wells can be correlated with variations in shear wave delays and amplitudes. Similarly, dim spots in amplitude variations can be correlated with local fracture swarms encountered by horizontal wells (Li, 1997).

Fractures also modify P-wave propagation giving rise to P-wave anisotropy. Fractures can thus be detected by measuring the change in P-wave interval velocity as a function of azimuth (VVAz) or by the change in the P-wave reflectivity or amplitude as a function of azimuth (AVAz). Both techniques offer a means of studying fracture intensity and orientation. Both techniques also require wide azimuth prestack data and entails considerable time and care in data conditioning and subsequent analysis.

Finally, seismic attributes generated from poststack seismic data help us in characterizing stratigraphic features that may comprise reservoirs. Coherence and curvature attributes are invaluable for such an analysis, and will form the basis of this talk on fracture detection.

Depending on the lithology and type of deformation, one technique may work better than another; however, in general, multiple techniques are evaluated and combined and then calibrated to well control to provide a more reliable prediction.

In this talk, I generalize the term seismic "attributes" to the full suite of seismic interpretation products including such prestack measurements as P-wave velocity anisotropy, Amplitude vs. Azimuth, and $\lambda\rho$-$\mu\rho$ inversion. Hunt et al. (2010a, 2010b) presented what I believe to be one of the first quantitative calibrations of seismic attributes to fractures, where the presence of fractures have measured by image logs through a horizontal borehole. In related work, Hunt et al. (2010a, 2010b), and Refunjol et al. (2010) have also used microseismic measures to correlate surface seismic measurements to induced fracture events created during reservoir stimulation. I attempt to summarize part of this work by modifying Nelson's table of parameters that lead to variations in fracture density (Table 1). Note that I have left out attributes that directly measure the presence of fractures such as AVAz, velocity anisotropy, and shear wave splitting.

Mapping structural deformation using volumetric curvature

Volumetric curvature is now a well-accepted tool in fracture mapping and is readily available in some form in most commercial interpretation software packages and through technical service providers. Curvature attributes do just that – they measure curvature, or the structural deformation associated with faulting, folding, slumping, erosion, karsting, and differential compaction. It is important to remember that curvature does not directly measure fractures. However, there is such a tight correlation between fracture intensity and the degree of structural deformation that many workers use the word fracture and curvature interchangeably.

Volumetric curvature allows to easily visualize and map structural features that are easily seen on the vertical seismic data, but may be difficult to map on all but those few continuous horizons having a high signal-to-noise ratio.

Figure 2 shows stratal slices through coherence, most-positive principal curvature, and most negative principal curvature volumes. Note that some but not much of the structural complexity is seen on the coherence image. In contrast, there is a direct correlation between what appear as anticlinal features on the vertical amplitude data and positive (red) curvature lineaments on the most-positive principal curvature volume and between synclinal features and negative (blue) lineaments seen on the most-negative principal curvature volume. The greater detail seen on the two curvature images does not imply that they are better than coherence; rather they are simply different. The differences are usually geological in nature. Rocks that deform by folding rather than faulting will have a curvature anomaly but no coherence anomaly. Furthermore, it is very common to have a fault zone represented by a major fault that gives rise to a suite of antithetic faultsÂ resulting in the fault offset being distributed more smoothly over a fault zone, giving rise to more continuous, but curved, reflectors (Ferrill and Morris 2008). Finally, fault systems are often joined by a network of relay ramps, which in turn can be associated with a curvature anomaly. However, it is important to recognize that the increased lateral delineation of faults by curvature over coherence may be a function of seismic data quality. Faults with throw less than a quarter wavelength may appear to be a continuous flexure such that they are seen by curvature but not by coherence. Likewise, faults imaged by seismic data that have less than optimal velocities and statics applied will be smeared, such that they will be seen by curvature and not by coherence.

Whether the cause be one of geology or of seismic data quality, I recommend using all structurally sensitive attributes in our interpretation.

3D multiattribute visualization

3D volume rendering is one form of visualization that involves opacity control to view the features of interest 'inside' the 3D volume. A judicious choice of opacity applied to edge-sensitive attribute sub-volumes such as curvature or coherence co-rendered with the seismic amplitude volume can both accelerate and lend confidence to the interpretation of complex structure and stratigraphy. In Figure 3, I show such a workflow at a different level from the survey shown in Figure 2. At this level, coherence does an excellent job of delineating the major faults. However, co-rendering coherence with the two curvature volumes provides a means of mapping horst, grabens, and relay-ramps. We can also use opacity to highlight anomalously strong lineaments in a 3D sense to better correlate structure seen on the attribute volume to the attribute images (Figure 4). With the proper tectonic deformation model, such images can be linked to hypothesize a fracture network.

Crossplotting

In addition to co-rendering, I evaluate an interpretation workflow that cross-plots pairs of edge-sensitive attributes. By crossploting coherence and an appropriate curvature attribute, we can define a polygon that highlights "clusters" that exhibit low coherence (indicating a discontinuity) and high curvature (indicating folding, flexing, fault drag, or differential compaction). Modern volume interpretation software allows us to link and display these interpreter-defined clusters in the seismic volume for further examination.

Once identified interactively, such visual 'clustering' can be used to supervise geobody delineation using neural networks and other classification algorithms. Such graphically-driven 'exploratory data analysis' saves the seismic interpreters considerable time and effort (Figure 5). Multiattribute co-rendering and crossplotting are powerful tools that lead to a better understanding of the spatial relationships between seismic attributes and the geologic objectives being pursued.

The need for calibration data

In an excellent case study, Narhari et al. (2009) have shown an excellent correlation between rose diagrams computed from surface seismic attributes and rose diagrams measured using image logs acquired in vertical wells. However, a serious challenge in the calibration of seismic attributes to fracture density is acquiring a sufficient sample statistic of control data. Fracture density has an unusual requirement of a large sample statistic because we must measure changes in the density of fractures, and thus simple point measurements will be insufficient. Although fractures may be observed in vertical or mildly deviated wells, the lateral size of the data being sampled in such wells remains very small, particularly for an attributes such as curvature which requires formation by formation calibration by thickness and rock type. Single vertical wells may miss nearby swarms of fractures simply by chance and give misleading calibration information.

I feel the solution to this problem is greater calibration with image logs and microseismic data acquired using horizontal wells. Although such wells are now routine, problems of temperature (e.g. in the Eagleford of the U.S.A.) or the use of oil-based drilling mud (e.g. in the Woodford shale of the Arkoma Basin of the U.S.A.) preclude the use of image logs. Nevertheless these critical calibration examples are slowly being pursued in other fractured target formations.

Conclusions

Through prediction of strain caused by an appropriate structural deformation model, coherence and curvature are valid methods of inferring fracture densities from surface seismic data. The advantages of such tools is that they are easily computed from the post-stack seismic data already in the hands of the interpreter. The wider use of image logs in horizontal wells, and emerging technology such as temperature logs that are sensitive to temperature differences in fluid flow through fractures will provide us with the necessary calibration to construct a suite of case studies that will better qunatify the correlation of open fractures to paleo deformation and the present day stress regime. I anticipate the use of fracture predicting techniques with curvature, as well as acquire what control data we can to move further from "inferring" and get closer to "predicting".

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Biography

Satinder Chopra received M.Sc. and M.Phil. degrees in physics from Himachal Pradesh University, Shimla, India. He joined the Oil and Natural Gas Corporation Limited (ONGC) of India in 1984 and served there till 1997. In 1998 he joined CTC Pulsonic at Calgary, which later became Scott Pickford and Core Laboratories Reservoir Technologies. Currently, he is working as Chief Geophysicist (Reservoir), at Arcis Corporation, Calgary. In the last 26 years Satinder has worked in regular seismic processing and interactive interpretation, but has spent more time in special processing of seismic data involving seismic attributes including coherence, curvature and texture attributes, seismic inversion, AVO, VSP processing and frequency enhancement of seismic data. His research interests focus on techniques that are aimed at characterization of reservoirs. He has published 7 books and more than 200 papers and abstracts and likes to make presentations at any beckoning opportunity. He is the Chief Editor of the CSEG RECORDER, the past member of the SEG 'The Leading Edge' Editorial Board, and the Ex-Chairman of the SEG Publications Committee.

He received several awards at ONGC, and more recently has received the **AAPG George C. Matson Award** for his paper entitled *'Delineating stratigraphic features via cross-plotting of seismic discontinuity attributes and their volume visualization'*, being adjudged as the best oral presentation at the 2010 AAPG Annual Convention held at New Orleans, the **'Top 10 Paper'** Award for his poster entitled *'Extracting meaningful information from seismic attributes'*, presented at the 2009 AAPG Annual Convention held at Denver, the **'Best Poster'** Award for his paper entitled *'Seismic attributes for fault/fracture characterization'*, presented at the 2008 SEG Convention held at Las Vegas, the '**Best Paper**' Award for his paper entitled *'Curvature and iconic Coherence–Attributes adding value to 3D Seismic Data Interpretation'* presented at the CSEG Technical Luncheon, Calgary, in January 2007 and the 2005 **CSEG Meritorious Services** Award. He and his colleagues have received the CSEG Best Poster Awards in successive years from 2002 to 2005.

He is a member of SEG, CSEG, CSPG, CHOA (Canadian Heavy Oil Association), EAGE, AAPG, APEGGA (Association of Professional Engineers, Geologists and Geophysicists of Alberta) and TBPG (Texas Board of Professional Geoscientists).