ON THE CALIBRATION OF SEISMIC ATTRIBUTES FOR RESERVOIR CHARACTERIZATION AND MONITORING

A brief review, based on an abstract for AAPG, 2003

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In the DOE-sponsored project, “Calibration of Seismic Attributes for Reservoir Characterization,” we have applied conventional and new methods of analysis and interpretation to four main data sets, including one time-lapse data set, and tested some specific technologies on additional data. Our goal was to use case studies to determine the physical basis for a number of seismic attributes, to identify pitfalls in the use of seismic attributes, and to develop new attributes as required for specific studies using a sound physical basis.

The main results of the project can be classified along these lines:

- Pitfalls (how to use ‘phantom’ horizons carefully)
- Unconventional attributes
  - Lateral extent of incoherence
  - Cross-correlation with ‘type’ seismograms
  - Impedance variation within specific layers
  - Detection techniques for pressure compartments and fluid migration
- Upscaling from sonic to seismic
- Methodology
- Recommendations for routine implementation
- Pressure-dependence of elastic properties
  - New relations based on dry-frame laboratory measurements
  - Importance of inclusion in time-lapse studies
- Reservoir behavior detected from time-lapse seismic observations

The public-domain Stratton data provided a challenge in thin-bed reservoir characterization in the absence of sonic-log calibration data. In general, the seismic character of potential productive zones is obscure in this data set, and horizons containing the pay zones are typically discontinuous. Previous work by other authors (Hardage et al., 1994) has demonstrated the apparent usefulness of simple attributes mapped along ‘phantom’ horizons which were tied at one well through a VSP and controlled by a

constant offset from a nearby continuously tracked horizon (Figure 1). We have demonstrated in this project that this apparent correlation is often an artifact of isopach changes, which dominate the interpretations based on simple attributes and on seismic facies analysis (Figure 2). However, if the interpreter understands that the interpretation is based on this correlation with bed thickening or thinning, reliable interpretations of channel horizons and facies can be made.

Figure 1: Tracked horizons and Phantom horizon used for comparison.

Figure 2: Comparison of (a) isopach map between the phantom and tracked horizons and (b) facies map constructed on the phantom horizon. The similarity strongly suggests that the facies classification (or any other attribute) is a product of the isopach differences between the phantom horizon and the actual (tracked) horizon.

The public-domain Boonsville data set (Hardage et al., 1996) provided another challenge in thin-bed reservoir characterization, in which the seismic character of a productive sand zone appears to be indistinguishable from that of a non-productive limestone. In this case, the interplay of impedance and thickness conspire with tuning to produce the similarity in most attributes. This problem was attacked with two methods. In the first method, a technique was developed that made use of the well-log interpretations to divide the area into a number of facies, following a reasonable geological model; then the seismic attributes, including seismic facies generated under various neural network procedures, were used to further subdivide those regional facies into productive and non-productive subfacies (Figure 3a). In the other method, a new technique involving cross-correlation of seismic waveforms was developed to provide a reliable map of various facies present in the area (Figure 3b); we think this technique holds great promise for other data sets as well, and it appears to be extremely robust.
The Teal South time-lapse seismic data set has provided a surprising set of data, extremely rich in interpretation possibilities. We (Pennington et al., 2001) used the limited log data and excellent seismic data of this classical bright-spot reservoir in the Gulf of Mexico to develop a robust seismic petrophysics model through waveform (stratigraphic) inversion for acoustic impedance. We then used this model, together with a pressure-dependent elastic modulus relationship, to predict the future seismic response of the reservoir, as it was being produced. Our predictions agreed with the observations. But observations of nearby, unproduced reservoirs also indicated a similar response, one that was not predicted with classical reservoir models or simulations (Figure 4). We concluded that these nearby reservoirs are undergoing a pressure drop in response to the production of the main reservoir, and that oil is being lost through their spill points (as gas comes out of solution), never to be produced. This set of observations has serious ramifications for engineering and exploitation techniques throughout the Gulf of Mexico.
The Wamsutter data set provided our most-challenging opportunities. This thin bedded low-porosity sand within the Almond formation of the western US has demonstrated to other studies that conventional seismic attributes are not typically useful in identifying depositional facies or productive zones. We sought unconventional attributes that were designed to identify those features which we concluded should be present in the seismic data as a result of knowing the rock physics associated with production. We found that a measure of lateral incoherence applied along a phantom horizon, designed to track a sand bar and its distal marine equivalent, provided extraordinary correlation with productivity from that sand bar (Figure 5). We also found that a technique we developed to identify high pressure from impedance variations along layers (Figure 6) correlates strongly with results from the DFM technique of TransSeismic International and may indicate pressure compartmentalization not associated with the sand bar; our interpretation is that these techniques are indicating zones of high fluid pressure and/or microfracturing. We also tested a variety of techniques of upscaling sonic and density logs to the seismic scale using a thin-layer effective medium model (Backus, 1962), and have significantly improved the tie between synthetic seismograms and real seismic data in this data set (Figure 7).

Figure 5: Wamsutter field area. The colored area defines the limits of our seismic coverage; the bright colors correspond to areas that have higher incoherence or variance within the uppermost Almond formation. The filled circles correspond in size to first-year production; in the western half of the figure, the production is from the uppermost Almond; in the eastern half of the figure, production is from the lowermost Almond.

Figure 6: The lowest-impedance volumes from within thin stratigraphic intervals were collected (some of these were in high-impedance sand layers, some others were in low-impedance coal layers). These were collected to describe overall volumes that may exhibit higher than average pore pressure and/or microfracturing.
Figure 7: A comparison of synthetic seismograms and their tie with actual seismic data. The best fit is found with a synthetic seismogram that was generated from a sonic using a depth-to-time conversion from a Backus average, together with sonic-log values that were calibrated by the ratio of the Backus- and time-averaged values.

As part of this project, seismic data from four areas was provided to a private company, TransSeismic International, for their proprietary processing. The Stratton, Boonsville, Waha (Woresham-Bayer, West Texas), and Wamsutter data sets were used; the first three of these are public-domain data sets, so others can investigate the results independently.

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